

# Assessment of energy demand-based greenhouse gas mitigation options for Canada's oil sands

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## ARTICLE INFO

### Article history:

Received 28 February 2019

Received in revised form

28 August 2019

Accepted 5 September 2019

Available online 5 September 2019

Handling editor: Prof. Jiri Jaromir Klemes

### Keywords:

LEAP model

GHG emissions

Abatement cost

Mining

Oil sands

Scenario analysis

## ABSTRACT

The main objective of this study is to assess energy-use reduction strategies in extraction and upgrading of oil sands for greenhouse gas mitigation in Canada's oil sands sector. A bottom-up integrated resource-planning model for oil sands extraction and upgrading processes was developed. The model is a novel application of an energy accounting-based framework and accurately simulates energy demand and supply in the oil sands from 2007 to 2050. Thirty energy-use reduction scenarios were evaluated covering in situ extraction, surface mining, and bitumen upgrading processes. The energy savings, greenhouse gas emission mitigation, and costs associated with each scenario were determined with the model. Implementing in situ energy-use reduction measures resulted in the highest single measure greenhouse gas mitigation potential of 86 million tonnes CO<sub>2</sub>e at a marginal greenhouse gas abatement cost of -\$91/tonne of CO<sub>2</sub>e by 2050. For the scenarios in surface mining and bitumen upgrading, the highest single measure greenhouse gas mitigation potentials are 17 and 16 million tonnes CO<sub>2</sub>e by 2050 at marginal greenhouse gas abatement costs of -\$65/tonne of CO<sub>2</sub>e and -\$21/tonne of CO<sub>2</sub>e, respectively. All strategies result in a negative \$/tonne of CO<sub>2</sub>e cost, indicating a net benefit for investing in the strategies. If the strategies are implemented together, there is an ultimate potential to reduce sector-wide cumulative energy consumption and greenhouse gas emissions in the oil sands by 8% and 7%, respectively, by 2050. Decision-makers at company or government levels can use these results to support both environmental and cost-saving initiatives.

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## 1. Introduction

Globally, the impacts of climate change are becoming evident and are driven by greenhouse gas (GHG) emissions from human activities (Edenhofer, 2015). The reduction of GHG emissions has become a shared challenge for all countries and economic sectors. The energy supply sector (energy resource extraction, conversion, storage, transport, and distribution) is the largest contributor to anthropogenic GHG emissions and is responsible for 35% of global GHG emissions (Edenhofer, 2015). About 5–10% of fossil-fuel-related GHG emissions can be attributed to the extraction and distribution of oil and gas and result primarily from heat generation via natural gas, electricity, and diesel-powered equipment, and fugitive emissions (Edenhofer, 2015). Oil extraction is a key contributor to these emissions, and the continuing depletion of

conventional oil sources, coupled with growing global fuel demands, is shifting the global focus toward extracting unconventional sources of oil. As a result, unconventional oil production is predicted to grow continuously until 2080 (Mohr et al., 2015). This poses a challenge to GHG emission mitigation since unconventional oil is typically more energy- and emission-intensive to extract and convert. Thus, it is imperative to evaluate methods of reducing GHG emissions from unconventional oil extraction processes if we are to reduce GHG emissions in the long term.

The Canadian oil sands (located in the province of Alberta, Canada) hold vast unconventional crude oil resources, and exploitation has grown quickly. Canada's oil reserves ranked third globally in 2014; 97% of these are Alberta's oil sands (NRCan, 2018). Cumulative oil sands production was 1.66 billion cubic meters as of 2014, or approximately 3.3% of the estimated ultimate potential (AER, 2015). Oil sands production in Alberta is anticipated to increase 62% by 2030 from 2015 levels (NEB, 2018). Besides this anticipated growth, the GHG emission intensity of the oil sands

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Abbreviations		List of variables	
bb1	Barrel	x	Process
CAD	Canadian dollar	y	Device
CHOPS	Cold heavy oil production with sand	n	Year
CSE	Cost of saved energy	D	Energy demand
CSS	Cyclic steam simulation	P	Bitumen production volume
GHG	Greenhouse gas	El	Energy intensity
GJ	Gigajoule	j	Energy form
IPCC	Intergovernmental Panel on Climate Change	k	Number of energy forms
IRPM	Integrated resource planning model	i	Discount rate
kWh	Kilowatt-hour	l	Life time of the technology
LEAP	Long-range Energy Alternatives Planning	CC	Capital cost
Mt	Million tonne	EP	Energy price
NEB	National Energy Board	Cc	Carbon price
NPV	Net present value	$\Delta C_E$	Difference between the scenario CO <sub>2</sub> e and the reference CO <sub>2</sub> e emissions
PJ	Petajoule		
SAGD	Steam-assisted gravity drainage		

extraction processes is significantly more than from conventional oil production (Charpentier et al., 2009). So, the oil sands are a key sector for both GHG emission concerns and clean technology development (Government of Canada, 2016).

Oil sands are composed of a viscous mixture of oil, sand, and water known as bitumen. Oil sands extraction relies on more energy- and emission-intensive processes than conventional oil extraction and requires upgrading prior to refining. There are two methods of producing bitumen – surface mining and in situ recovery. Surface mining involves digging bitumen from an open pit mine and transported by truck. Surface mining is feasible if the bitumen reservoir is found near the surface. If the reservoir is deep, in situ recovery is employed to produce the bitumen through wellbore pumping. There are currently three methods used for in situ recovery: cold heavy oil production with sand (CHOPS) (similar to conventional heavy oil), steam-assisted gravity drainage (SAGD), and cyclic steam stimulation (CSS). SAGD and CSS involve injecting the reservoir with steam to reduce the viscosity of the bitumen so it can be more easily pumped. SAGD typically has higher production rates than CHOPS and CSS and is usually the preferred extraction method. Approximately 20% of the remaining oil sands reserves are recoverable with surface mining; the rest require in situ recovery (AER, 2018b).

Some emissions mitigation pathways for the oil sands have been studied previously. Process-based models have been developed and used to evaluate energy use, GHG emissions, and GHG reduction strategies. These models have established baseline energy use and GHG emission data, as well as GHG mitigation potentials for technology implementation in specific processes. Nimana et al. (2015a, 2015b) developed a fundamental engineering principles-based model to estimate energy consumption and GHG emissions from oil sands extraction and upgrading. This model quantified energy and GHG emissions intensities of oil sands operations. Nduagu and Gates (2015, 2016) used process analysis to evaluate the decarbonization of natural gas prior to its use in oil sands operations and performed an economic assessment on the technology. Lazzaroni et al. (2016) simulated integrated SAGD and upgrading plant configurations using process modelling. The study produced a range of energy and emission intensities for the configurations.

While the process models generate valuable energy use and GHG emissions data, the evaluation of long-term strategies for reducing sector-wide emissions is well suited to integrated resource planning models (IRPMs). An IRPM can be used in a

long-term assessment of GHG mitigation strategies as it assesses changes that occur in both the energy demand (end-use energy-using equipment, resource requirements) and the supply (energy generation, installed capacity, fuel mix, technology mixes, resource adequacy, etc.) sides of an energy system (Shrestha and Marpaung, 2006). Thus, an IRPM allows for the sector-wide analysis of carbon prices, demand-side management programs, energy efficiency (Yáñez et al., 2018), emissions (Sun et al., 2018), and others (Shrestha and Marpaung, 1999).

IRPMs have been applied to the oil sands in a limited capacity and there is room for development in this area. They have been previously used to study energy supply and infrastructure changes for GHG mitigation strategies in the oil sands. Elsholkami et al. (2016) used an energy optimization model to assess the impacts on GHG emissions from incorporating renewable energy technologies into oil sands operations. The study concluded that renewables such as geothermal and biomass can satisfy meaningful amounts of oil sands energy requirements and be key contributors to GHG emission reductions. Ouellette et al. (2014) used an IRPM to conduct scenario analysis and evaluate the role of cogeneration in reducing GHG emissions. They found that 13–26% of Alberta's emissions could be mitigated by 2030 by using cogeneration for electricity generation. Charry-Sanchez et al. (2014) developed an optimization model to study optimal upgrading processes. They identified optimal upgrading configurations under different natural gas prices, CO<sub>2</sub> constraints, and naphtha yields. Ordorica-Garcia et al. (2008) conducted a case study with an energy optimization model on CO<sub>2</sub> reduction scenarios for the oil sands. Their work investigated optimal energy infrastructure for oil sands mining and found the potential to reduce CO<sub>2</sub> emissions by up to 30% of the 2003 level.

Only a few studies relate specifically to reducing energy demands as a GHG mitigation strategy. Austin-Adigio and Gates (2019) investigated the benefits of outfitting automated control devices in SAGD operations. The study shows the efficacy of the proposed technology. Carreon et al. (2015) evaluated energy efficiency options using pinch analysis. The study focused on process-level in situ analysis.

The above-mentioned oil sands studies assess energy supply, infrastructure, or single energy-use reduction strategies as GHG mitigation strategies. There is no comparative assessment of a range of energy-use reduction strategies for GHG emissions mitigation in the literature. This information is needed to gain insights

into the ultimate GHG mitigation potential in the oil sands via energy-reduction strategies, as well as to evaluate and compare the marginal cost effectiveness of each option. We shrink this knowledge gap by assessing a range of oil sands energy-demand reduction strategies for sector-wide GHG mitigation potential and marginal cost effectiveness (\$/tonne of CO<sub>2</sub>e mitigation) over the long term. A key novelty of this work is the development and application of an accounting-based sector-wide IRPM to the oil sands sector for the analysis. To the best of our knowledge, only optimization-based IRPMs have been applied to GHG mitigation studies for the oil sands mining sector.

The overall aim of this study is to techno-economically assess a range of energy-use reduction strategies for reducing oil sands GHG emissions between 2018 and 2050. The results are intended as decision support for planners and policy-makers developing strategies related to energy, climate, and environment. The specific objectives are to develop an IRPM for the oil sands sector, identify energy-demand reduction options, use the model to determine the GHG emission mitigation potential and associated marginal costs of these options, and conduct a sensitivity analysis of the results.

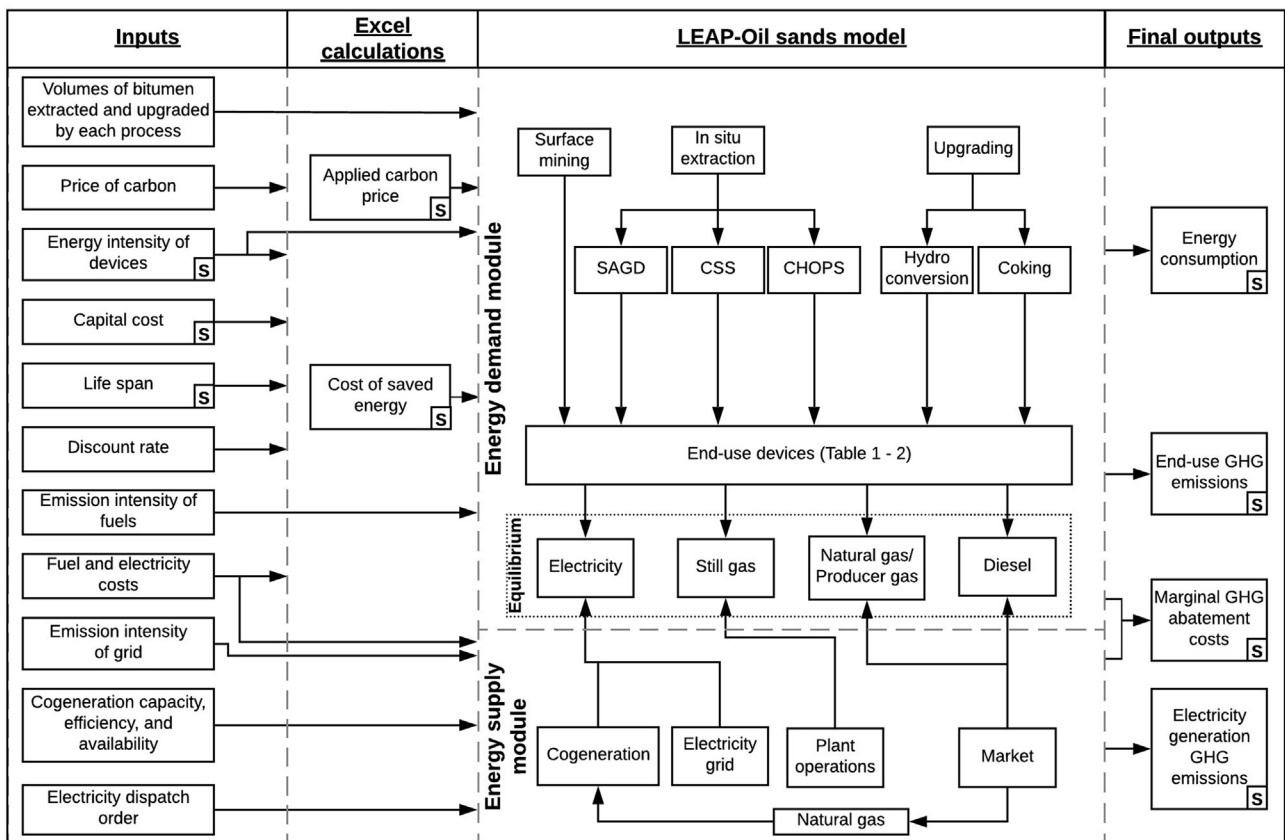
**2. Methods**

This study was conducted in three main stages. The first was to develop a bottom-up energy-accounting model of the oil sands sector. This model covers end-use energy using processes in the oil sands and estimates GHG emissions based on the energy consumption. The second stage is to use the model to project a reference scenario to 2050 considering expected changes in crude

bitumen production. The third stage is to perform scenario analysis by changing some variables in the reference scenario to reflect an energy-demand reduction strategy, such as cost and energy intensity of a process, and to determine the corresponding change in GHG emissions and costs compared to the reference case. The results for a range of scenarios are then compared. Section 2.1 gives an overview of the modelling framework. Section 2.2 describes the development of the oil sands energy model. Section 2.3 explains how the scenario analysis was conducted.

**2.1. Framework**

Fig. 1 is a representation of the model developed for this study. The model covers the years 2007–2050 and was developed using various input data, Excel, and the Long-range Energy Alternatives Planning (LEAP) software (Heaps, 2016). The input data variables were either statistically sourced, assumed, or gathered from literature sources; all input data are defined in the subsequent subsections corresponding to where their arrow terminates in Fig. 1. LEAP provides a calculation framework to model energy systems. An oil sands-specific energy model was developed in LEAP (which we call LEAP-Oil sands) by defining energy demand and energy supply modules. The energy demand module was developed with oil sands production activity (further defined in Section 2.2.1.1), the technologies and processes that produce oil, and their energy requirements (further defined in Section 2.2.1.2). The energy supply module supplies electricity through cogeneration and grid processes (further defined in Section 2.2.2). The LEAP-Oil sands model calculates fuel-specific end-use energy consumption and GHG



Data in annual time steps from 2007-2050

[S] Indicates data that are unique to each scenario

Fig. 1. Oil sands mining sector model framework.

emissions using the oil production activity in each process (surface mining, in situ extraction, upgrading) and corresponding end-use energy intensities (Tables 1 and 2).

The input data in Fig. 1 with arrows terminating at the Excel calculation boundary was used to develop an Excel-based techno-economic model to determine the costs of saved energy (CSE) associated with energy reduction options. The outputs from this CSE model were used in the LEAP-Oil sands to perform the scenario analysis (further described in Section 2.3).

The developed model was used to simulate annual energy demand and supply of the oil sands reference and energy reduction scenarios. Annual energy consumption, GHG emissions, and marginal GHG abatement costs are the final outputs for each scenario. The calculation of the costs is explained in Section 2.3.2. The outputs were used to develop marginal GHG abatement cost curves to comparatively assess the GHG emission mitigation potential and marginal GHG abatement costs (\$/tonne of CO<sub>2</sub>e) for each scenario. Marginal abatement cost curves have been shown to be a useful tool to convey marginal GHG abatement cost results (Huang et al., 2016).

## 2.2. Development of the LEAP-Oil sands model

The LEAP software platform was chosen to model the oil sands sector because of its bottom-up nature, ability to integrate energy supply with demand, and scenario analysis capabilities. LEAP's bottom-up calculation methods are also preferred for the evaluation of GHG mitigation options. Bottom-up models give a closer approximation to the costs of mitigating carbon emissions compared to top-down approaches (Krause, 1996). Top-down methods typically calculate energy consumption as a function of macro-economic variables such as GDP, capital investment, or labor and materials using historical time-series data to formulate correlations (Nyboer, 1997). Such an approach limits the model's ability to analyze technological improvements since estimates from historical data may fail to respond to innovations. On the other hand, a bottom-up approach (toward end-use analysis) can be used to assess the economic and technical potential for energy efficiency and operational improvements from different technologies (Nyboer, 1997). LEAP was developed by the Stockholm

Environment Institute and has been used for energy modeling and GHG emission mitigation assessment by the United Nations Framework Convention on Climate Change (UNFCCC), Asia Pacific Economic Cooperation (APEC), and many other organizations (LEAP applications, 2017). LEAP was used to conduct long-term energy demand and GHG emissions forecasting of transport (Fan et al., 2017) as well as environmental assessments in the iron and steel (Tan et al., 2019), chemical (Talaie et al., 2018), and electricity generation (Cai et al., 2007) sectors.

### 2.2.1. Energy demand module

The demand module of the LEAP-Oil sands model was structured using the end-use devices, energy intensities, and production volumes. Calculations in the model were completed in yearly time steps from the bottom up. Annual energy demand was calculated at the device level with Equation (1). The energy intensity, defined as gigajoule/barrel (GJ/bbl) or kilowatt-hour/barrel (kWh/bbl) for each end-use device, is multiplied by the bitumen production associated with that end-use device. Summing the energy demand across devices gives the overall energy demand for a particular process or sector. GHG emissions are also accounted for at the device level. Tier 1 Intergovernmental Panel on Climate Change (IPCC) emission factors for natural gas and diesel were applied to the amount of energy consumed for each fuel for each end-use device (Eggleston et al., 2006). The heating value and emission factor for still gas were obtained from a Canadian Energy Research Institute study (CERI, 2015) and the United States Environment Protection Agency (US EPA) (EPA, 2015), respectively. The summation of GHG emissions across devices gives the overall GHG emissions for a particular process or for the oil sands sector as a whole.

$$D_{x,y,n} = P_{x,n} * EI_{x,y,n} \quad 1$$

In the equation,  $D$  is the energy demand,  $P$  is the bitumen production volume,  $EI$  is the device energy intensity,  $x$  is the process (surface mining, SAGD, etc.),  $y$  is the device (steam generator, diesel truck, etc.), and  $n$  is the year.

2.2.1.1. Production. The production data for different oil sands production processes for the years 2007–2050 are presented in

**Table 1**  
Surface mining, SAGD, CSS, and CHOPS end-use devices and energy intensities.

Subsector	End-use device	Fuel Intensity			Source
		Natural gas/Produced gas (GJ/bbl)	Electricity (kWh/bbl)	Diesel (GJ/bbl)	
Surface mining	Trucks (front-end loaders)	–	–	0.14	Ordorica-Garcia et al. (2007)
Surface mining	Conveyor belts for slurry transport	–	0.17	–	Cannon et al. (2007)
Surface mining	Drilling equipment/Power shovels for ore excavation	0.002	8.00	–	Cannon et al. (2007)
Surface mining	Crushers	–	0.50	–	Cannon et al. (2007)
Surface mining	Rotary tumblers for mixing	–	0.50	–	Cannon et al. (2007)
Surface mining	Air compressors	–	0.01	–	Cannon et al. (2007)
Surface mining	Motors for floatation	–	0.10	–	Cannon et al. (2007)
Surface mining	Steam generation units	0.25	–	–	Cannon et al. (2007)
Surface mining	Pumps for the transport of steam, slurry, bitumen and tailings	–	4.00	–	Cannon et al. (2007)
SAGD	Steam pumps	–	14.51	–	CERI (2015)
SAGD	Compressors	–	2.00	–	CERI (2015)
SAGD	Mixers	–	0.17	–	CERI (2015)
SAGD	Process heat	1.01/0.17	–	–	CERI (2015)
CSS	Steam pumps	–	16.95	–	CERI (2015)
CSS	Compressors	–	2.34	–	CERI (2015)
CSS	Mixers	–	0.19	–	CERI (2015)
CSS	Process heat	1.14/0.29	–	–	CERI (2015)
CHOPS	Water pumps	–	3.00	–	Cannon et al. (2007)
CHOPS	Compressors	–	2.34	–	Cannon et al. (2007)
CHOPS	Mixers	–	0.19	–	Cannon et al. (2007)
CHOPS	Process heat	0.50	–	–	Cannon et al. (2007)

**Table 2**  
Coking-based and hydroconversion-based upgrading end-use devices and energy intensities (CERI, 2015).

Subsector/End-use device	Fuel Intensity		
	Natural gas (GJ/bbl)	Still gas (GJ/bbl)	Electricity (kWh/bbl)
<b>Coking-based upgrading</b>			
Steam generation unit	0.06	0.06	–
Crude distillation unit	0.01	0.05	0.84
Vacuum distillation unit	0.01	0.05	0.42
Gasoil hydrotreater	0.002	0.01	2.42
Other HT units	0.002	0.02	4.41
SMR plant	0.05	0.39	0.42
Coking unit	0.01	0.07	0.84
Sulphur plant	–	–	0.84
Other utilities	–	–	0.32
<b>Hydroconversion-based upgrading</b>			
Steam generation units	0.04	0.15	–
Residue hydroconversion with integrated hydrotreater	0.02	0.09	12.09
Sulphur recovery facilities	0.01	0.05	1.32
Solvent deasphalting	0.007	0.03	–
Distillation unit	0.07	0.27	1.99
Hydrogen plant	0.07	0.25	0.66
Other utilities	–	–	0.49

[Table A1 in the supplementary file](#). Data for 2007–2017 are historical while the 2018–2040 data are projections from Canada's National Energy Board (NEB) (NEB, 2018). Production values for the years 2041–2050 were extrapolated for the in situ mining and upgrading subsectors based on 2030–2040 growth. For surface mining, the projected production volume remained constant from 2022 to 2040 and is considered the same up to 2050. The historical annual production shares of CSS, SAGD, CHOPS, hydroconversion-based, and coking-based upgrading were obtained from the Energy Resources Conservation Board (ERCB) and the Alberta Energy Regulator (AER) to 2017 (AER, 2018b). The share of CSS and CHOPS fell from 66% in 2007 to 30% in 2017. Hence, any increase in in situ production from 2018 is assumed to result in an increase in production by SAGD recovery type only. The production volumes of CSS and CHOPS are held constant (2017 value) until 2050. For upgrading, the share of production between hydroconversion-based and coking-based methods did not follow any apparent trend between 2007 and 2017, so the average production share for the last 5 years of available data (2012–2017) is assumed for 2018–2050.

**2.2.1.2. End-use devices.** An inventory of energy-using devices and their fuel-use energy intensities for each oil sands extraction and upgrading process was compiled from publicly available data (Jeff et al., 2009), pilot-scale plants and industrial best practice guides (Cannon et al., 2007; CERI, 2015), research by Nimana et al. (2015a, 2015b), and the theoretical engineering model results of Ordorica-Garcia et al. (2007). This information was used to develop the energy demand portion of the LEAP-Oil sands model and inputs into Equation (1).

In surface mining, ore is excavated by removing the layers of overburden using power shovels and moved out of the mining site using loaders and trucks. The extracted ore is crushed, mixed with warm water, and pipelined to extraction facilities. The slurry then undergoes separation and flotation processes to extract bitumen (Nimana et al., 2015a). The device-level energy intensities are shown in Table 1.

In situ production was modelled for SAGD, CSS, and CHOPS. In SAGD, steam is injected into the reservoir and the bitumen, water, and associated gas flow into the lower well by gravity and are pumped to surface treatment facilities for processing. Bitumen is separated and the associated gas and water are reused in the boilers for steam generation (Bohm et al., 2012; Jeff et al., 2009). CSS is a

batch process in which the injected steam soaks in the reservoir and the bitumen is then pumped to the surface for processing (Jeff et al., 2009). In CHOPS, sand is influxed into a perforated oil well and progressive cavity pumps pump the bitumen, sand, clay, and water from the reservoir. The energy intensities for SAGD, CSS, and CHOPS are shown in Table 1.

Bitumen is converted to synthetic crude oil (SCO) through upgrading. Generally, the upgrading process consists of a primary upgrading step to increase the hydrogen-to-carbon ratio and a secondary upgrading step to reduce sulphur content in the products to below 0.5%. The hydrogen-to-carbon ratio can be increased through either the carbon rejection process (coking) or the hydrogen addition process (hydroconversion (LC-finishing)) (Nimana et al., 2015b). The end-use energy intensities for coking-based and hydroconversion-based upgrading are shown in Table 2.

### 2.2.2. Energy supply module

The energy supply module responds to energy demands and supplies the fuels and electricity needed to meet the demands of the end-use devices (energy supply-demand equilibrium). Fuel, electricity costs, and upstream electricity emissions are accounted for here. Still gas is considered the produced and consumed associated gas from the extraction and upgrading processes. Natural gas and diesel are supplied by the market. Energy consumption and emissions (IPCC Tier 1) occur at the cogeneration stage, as natural gas is combusted for on-site electricity generation. Electricity is also supplied from a grid source and a grid emission factor is applied (g CO<sub>2</sub>e/megawatt-hour [MWh]) to account for upstream grid electricity generation emissions.

Canadian oil sands industry electricity requirements are supplied by both the Alberta power grid and on-site natural gas cogeneration. The natural gas cogeneration and electricity grid supply parameters are given in Table 3. Cogeneration capacity is based on projections from the Alberta Electric System Operator (AESO, 2016). Cogeneration efficiency is for the electricity generation portion of the plant but takes into account the savings attributed to cogeneration of steam. The maximum availability variable represents the amount of electricity produced that is consumed by oil sands operations. This value is lower than the total cogeneration electricity produced, as a portion of electricity produced on site from oil sands cogeneration has historically been exported to the Alberta grid (OSCA, 2014). It is expected that the amount of electricity exported to the grid will decrease because on-site electricity

**Table 3**  
Electricity supply parameters.

Supply source	Dispatch order	Capacity (GW) AESO (2016)	Efficiency	Maximum availability for oil sands operations	Emission factor (tonne CO <sub>2</sub> e/MWh)
Oil sands natural gas cogeneration	1	2009: 2.39 2020: 3.08 2030: 3.49 2040: 3.69 2050: 3.91	60% (U.S. EPA CHP, 2017)	2009–2015: 53% 2020: 60% 2030–2050: 70%	IPCC Tier 1 for electricity generation from natural gas
Electricity grid	2	N/A	N/A	N/A	2018: 0.8 2020: 0.7 2030: 0.3 2040: 0.3 2050: 0.3 (Davis et al., 2019)

demand increases at a faster rate than cogeneration capacity growth (OSCA, 2014). It is assumed that the available power from on-site cogeneration will be consumed at an increasing rate throughout the study period and reach 70% by 2030. The time-wise distribution of electricity demand (base-intermediate-peak loads) is based on an electricity load curve from AESO (2016). Oil sands cogeneration is first dispatched to meet the demand up to the maximum availability, and then the grid is used to fill the remaining demand. The electricity grid supply emission factors were derived from earlier work by one of the authors (Davis et al., 2019) and considers recent announcements put forth by the Alberta Climate Leadership Plan (Government of Alberta, 2015) including a coal power phase-out by 2030 and renewable generation capacity increases (AESO, 2016).

### 2.3. Scenario analysis

#### 2.3.1. Energy-demand reduction scenarios

The energy savings potential and different scenario categories were developed from strategies reported by Bohm et al. (2012) and are shown in Table 4. Table 5 gives the calculated fuel savings for each scenario. The energy intensities for the end-use devices were considered to remain constant for the reference scenario over the study period. To evaluate each scenario, the fuel savings (from Table 5) and cost data (explained in Section 2.3.2) were applied in the model and the results were compared to the reference scenario.

Energy-demand reduction scenarios evaluated in this study are limited to investments that have a capital and operational improvement payback period of less than 5 years. Since the

scenarios do not include major technological advancements (which are slow to penetrate) and focus more on operational improvements that can be implemented over a short-term period, it is assumed that the implementation is 100% sector-wide from 2018 for each scenario.

The total energy demand savings for each scenario by energy type are calculated using Equation (2). The corresponding GHG emissions savings are calculated similarly.

$$E_{j,n} = D_{RefSce,j,n} - D_{EESce,j,n} \quad 2$$

In the equation,  $E$  is the energy saved,  $n$  is the year,  $j$  is the energy form,  $D_{RefSce}$  is the energy demand in reference scenario, and  $D_{EESce}$  is the energy demand in energy efficiency scenario. The summation of the energy savings across all years gives the cumulative energy consumption.

#### 2.3.2. Cost of saved energy and abatement cost

Techno-economic assessments of the scenarios were carried out by calculating the CSE in each year. The CSE is expressed in dollars per gigajoule (\$/GJ) and is the cost per unit energy saved relative to the reference scenario. Equation (3) was used to calculate the CSE for each scenario. The scenario-specific capital cost and lifetime of the technology are shown in Table 6. The numerator denotes the sum of the annualized capital cost (\$/bbl) of the energy efficient technology and the annual energy cost savings (\$/bbl) achievable from different energy forms in a year. The denominator represents the energy reduction (GJ/bbl) achievable from an efficient technology as explained in the previous section. Billingsley et al. (2014)

**Table 4**  
Description of scenarios (Bohm et al., 2012).

Scenario category	Applicable processes	Description
Reference	Surface mining, in situ, upgrading	Existing energy intensities
Energy management and monitoring	Surface mining, upgrading	Improved energy monitoring and management for activities related to the day-to-day stewardship of energy use
Use efficiency	Surface mining	Improved energy efficiency of the operating plant due to reduction in unplanned outages, idling time and operating it reliably
Heat exchange/integration & fired heater efficiency	Surface mining, in situ, upgrading	Improved heat exchanger networks in the plant facility. Improvement to the waste heat recovery and the operation of heaters and boilers
Utilities	Surface mining, in situ	Required utilities are produced more efficiently by improving boiler efficiencies and using power-recovery turbines
Process/technology changes	Surface mining, in situ, upgrading	Existing process operating parameters are optimized (for example, operating pressure, flue gas temperature)
Control system	Surface mining, upgrading	Efficiency improved in using advanced process control systems and online analyzers. These control systems maintain the optimal operation of processes (for example, adding controllers to maintain steady flow on the tailings lines)
Heat loss to earth and water	In situ	Efficiency improved in in situ mining processes to reduce heat losses to the earth and water. Opportunities related to efficient development of the well and capturing waste heat lost through tailings disposal
Fuel type and use	Upgrading	Assesses efficiency improvements in fuel type and use changes (switching from a more to a less carbon-intensive fuel)

**Table 5**  
Process energy savings by scenario.

Scenario Name	Scenario	NG savings (%)	Electricity savings (%)
SM-EM	Surface mining – Energy monitoring and management	2.14	2.14
SM-UE	Surface mining – Use efficiency	0.63	0.05
SM-HE	Surface mining – Heat exchanger/integration and fired heater efficiency	1.91	–
SM-UT	Surface mining – Utilities	1.25	0.11
SM-P&T	Surface mining – Process and technology changes	0.63	0.06
SM-CS	Surface mining – Control system	5.91	2.35
IS-HL	In situ – Heat loss to earth and water	0.12	0.10
IS-HE	In situ – Heat exchanger/integration and fired heater efficiency	3.95	–
IS-UT	In situ – Utilities	3.95	3.95
IS-P&T	In situ – Process and technological changes	0.12	–
UP-Fuel	Upgrading – Fuel type and use	1.22	–
UP-HE	Upgrading – Heat exchanger/integration and fired heater efficiency	1.83	–
UP-EM	Upgrading – Energy monitoring and management	0.58	0.58
UP-P&T	Upgrading – Process and technology changes	0.82	0.82
UP-CS	Upgrading – Control system	1.02	1.02

**Table 6**  
Input data for the development of the CSE (Bohm et al., 2012).

Scenario	Life time, n (years)	Capital cost (\$/bbl of bitumen production)
SM-EM	35	0.02
SM-UE	35	0.01
SM-HE	35	0.03
SM-UT	35	0.03
SM-P&T	35	0.01
SM-CS	35	0.02
IS-HL	35	0.02
IS-HE	35	0.24
IS-UT	35	0.54
IS-P&T	35	0.02
UP-Fuel	15	0.02
UP-HE	15	0.17
UP-EM	15	0.01
UP-P&T	15	0.01
UP-CS	15	0.01

used a similar method to calculate the cost of saved energy of electricity efficiency programs.

$$CSE_n = \frac{(CC_{eff}) * \frac{i(1+i)^l}{(1+i)^l - 1} + \sum_{j=1}^k [(El_{eff,j} - El_{exist,j}) * EP_{j,n}]}{\sum_{j=1}^k (El_{eff,j} - El_{exist,j})} \quad 3$$

In the equation,  $CSE$  is the cost of saved energy,  $n$  is the year,  $CC_{eff}$  is the capital cost of the energy reduction technology (\$/bbl),  $i$  is the discount rate,  $l$  is the lifetime of the technology,  $j$  is the energy form,  $k$  is the number of energy forms,  $El_{eff,j}$  is the energy intensity of energy form  $j$  of the energy reduction technology,  $El_{exist,j}$  is the energy intensity of energy form  $j$  of the existing technology, and  $EP$  is the energy price.

Because energy price varies from one year to the next, the CSE is different for each year during the forecast period. The end-use price of electricity for the industrial sector was obtained from the NEB to the year 2040 and extrapolated to 2050 based on the 2015–2040 growth trend (NEB, 2018). The end-use price of natural gas from the AER was used to 2026, projected to 2040 assuming the same year-on-year percentage change as the Henry Hub benchmark price and extrapolated to 2050 based on the 2015–2040 growth trend (AER, 2018a; NEB, 2018). Historically, the Henry Hub natural gas price follows the same trend as that of the end-use natural gas prices. The electricity and natural gas prices are shown in Table A2 in the supplementary file.

The carbon price in Alberta was included in the model as an externality cost. Subsector-specific benchmarked emission allocations were derived from the 2018 Carbon Cost Incentive Regulation

(CCIR) and the Standard for Establishing and Assigning Benchmarks (Government of Alberta, 2017, 2018b). For each scenario, the emissions for which a carbon price was charged was calculated by taking the difference between the LEAP-oil sands output of total GHG emissions and the CCIR benchmark emission allocations. The nominal carbon prices (\$30/tonne of CO<sub>2</sub>e in 2018, \$40/tonne of CO<sub>2</sub>e in 2021, and \$50/tonne of CO<sub>2</sub>e from 2022 onwards) established in the Climate Leadership Plan and the CCIR compliance phase-out obligations (50% in 2018, 75% in 2019, and 100% in 2020) were then applied to this difference (Government of Alberta, 2017, 2018a, 2018b). All the costs and prices were adjusted to 2016 Canadian dollars (CAD) (Bank of Canada, 2017) and all future costs are considered in real terms.

The CSE, energy savings (calculated using Equation (2)), GHG emissions savings, and carbon price were used in the model to calculate the total net present value (NPV) and marginal abatement costs (MAC) through Equation (4) and Equation (5), respectively, for each scenario:

$$NPV_x = \sum_{n=2018}^{2050} \frac{\sum_{j=1}^k (CSE * E)_{j,n} + (C_C * \Delta C_E)_n}{(1+i)^{n-2018}} \quad 4$$

$$MAC_x = \frac{\Delta NPV_x}{\Delta C_{E,x}} \quad 5$$

In these equations,  $E$  is the energy saved annually,  $n$  is the year,  $j$  is the energy form,  $k$  is the number of energy forms,  $CSE$  is the cost of saved energy,  $C_C$  is the carbon price,  $\Delta C_E$  is the difference between the energy-reduction scenario CO<sub>2</sub>e and the reference scenario CO<sub>2</sub>e,  $i$  is the discount rate,  $MAC$  is the marginal abatement cost,  $x$  is the process being considered in the scenario,  $\Delta NPV$  is the difference between the scenario NPV and the reference NPV.

### 3. Results and discussion

#### 3.1. Reference scenario and model validation

Energy demand and GHG emissions are projected to increase approximately 3 and 4 times, respectively, by 2050 when compared to 2007. The reference scenario results were compared to other publicly available oil sands energy (CERI, 2015) and GHG emission data sources (ECCC, 2017). Fig. 2 illustrates the differences between the LEAP-Oil Sands model's calculated energy demand and GHG emissions from the other sources. The average difference is approximately 1% for energy demand and 2% for GHG emissions for the years 2007–2015, and less than 5% for the 2020 and 2030 GHG

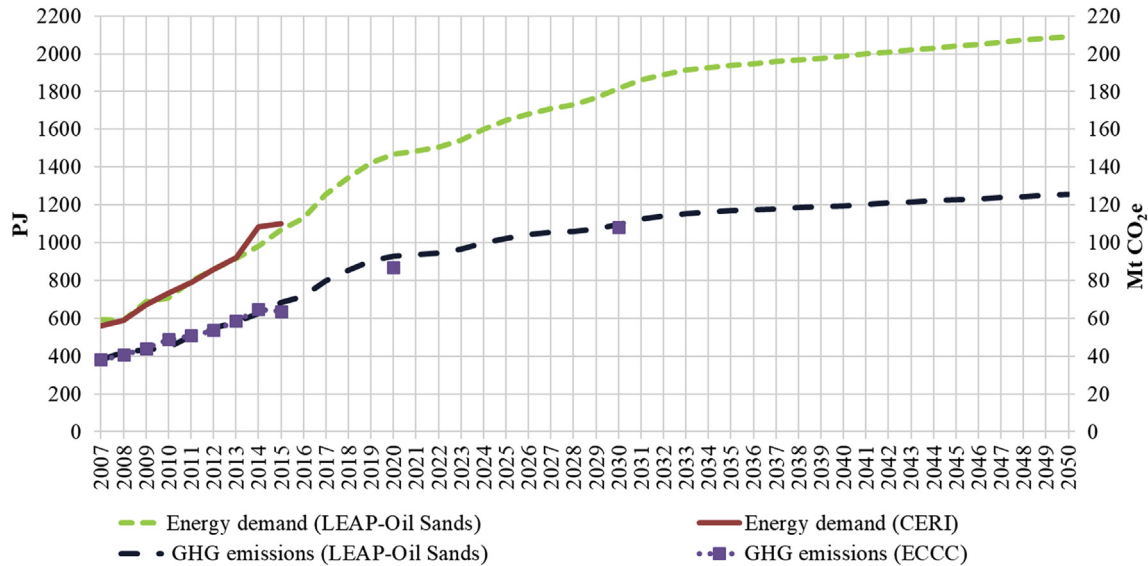


Fig. 2. Energy demand and GHG emissions comparisons (2007–2015) and reference scenario projections to 2050 (excludes venting and flaring emissions).

emission data points. The projected energy demand and GHG emissions for the oil sands reference scenario in the oil sands mining subsectors are given in Table A3 and Table A4 in the supplementary file.

### 3.2. Scenario analysis

#### 3.2.1. Cost of saved energy

The CSE is calculated for each of the scenarios as discussed in section 2.3.2. The calculated CSEs are shown in Table 7. All the scenarios have cost savings after considering the incremental increases in investment and savings due to energy reduction. The cost savings increased every year because of increases in electricity and natural gas prices. It should be noted that a higher CSE may not result in a higher marginal GHG abatement cost as the marginal GHG abatement cost depends also on the GHG emission intensity of the fuels used.

#### 3.2.2. Marginal GHG abatement

The energy demand savings, costs, and GHG mitigation results for all the scenarios discussed above are summarized in Table 8. Fig. 3 and Fig. 4 show the marginal GHG abatement cost curves for

Table 7  
Cost of saved energy for the scenarios.

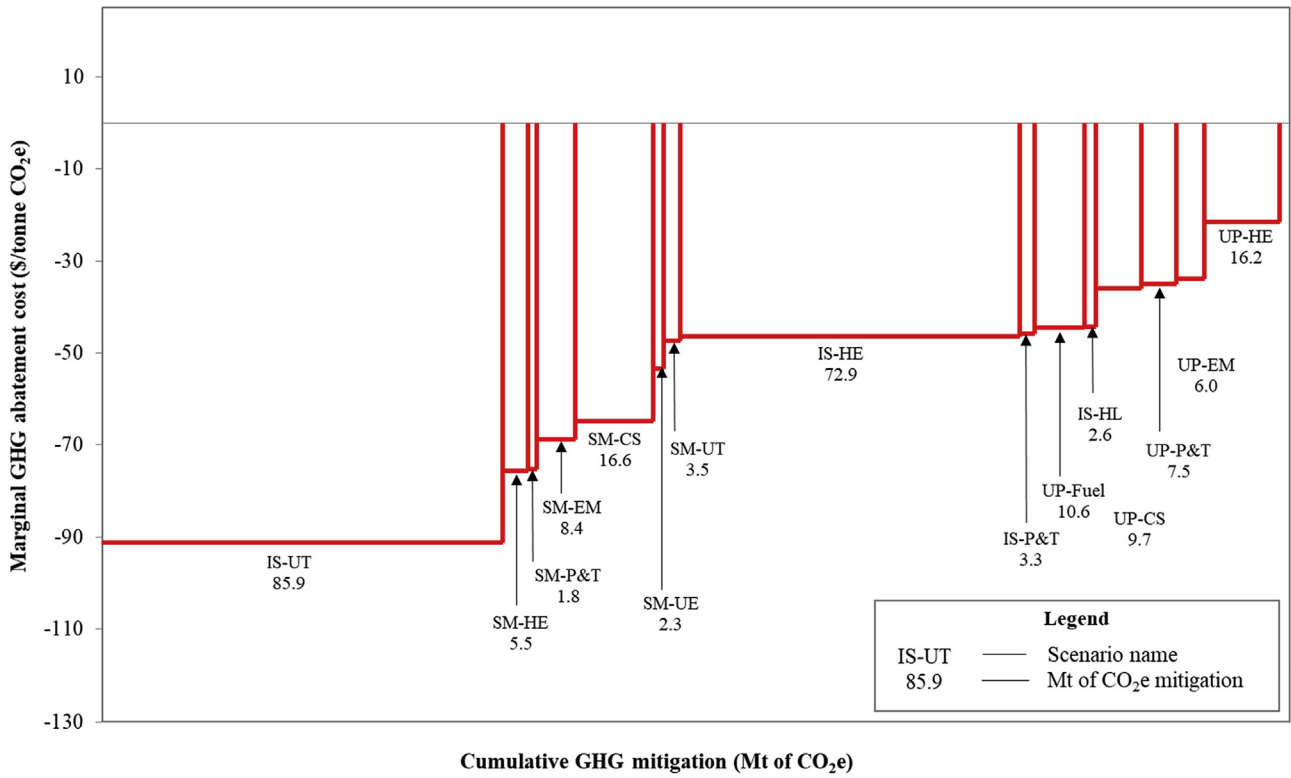
Scenario	CSE (2016 CAD/GJ)			
	2020	2030	2040	2050
SM-EM	-4.6	-6.9	-7.5	-6.2
SM-UE	-2.2	-3.9	-4.3	-6.0
SM-HE	-1.8	-3.5	-3.8	-5.4
SM-UT	-1.6	-3.4	-3.7	-5.5
SM-P&T	-4.2	-6.4	-7.0	-9.2
SM-CS	-3.5	-5.6	-6.3	-8.3
IS-HL	-1.9	-3.8	-4.2	-6.0
IS-HE	-2.0	-3.7	-4.0	-5.7
IS-UT	-2.2	-4.0	-4.4	-6.3
IS-P&T	-1.9	-3.7	-4.0	-5.6
UP-Fuel	-2.3	-4.0	-4.3	-6.0
UP-HE	-0.9	-2.6	-2.9	-4.6
UP-EM	-3.0	-4.8	-5.2	-7.1
UP-P&T	-3.0	-4.9	-5.3	-7.1
UP-CS	-3.1	-4.9	-5.3	-7.2

Table 8  
Summarized scenario results.

Scenario	Cumulative energy savings (PJ)		Cumulative GHGs mitigated (Mt)		Marginal GHG abatement cost (2016 CAD/tonne of CO <sub>2</sub> e)	
	2030	2050	2030	2050	2030	2050
SM-EM	50	127	3.7	8.4	-82	-69
SM-UE	16	40	0.9	2.3	-66	-53
SM-HE	39	99	2.2	5.5	-99	-76
SM-UT	24	62	1.4	3.5	-61	-47
SM-P&T	12	31	0.7	1.8	-89	-75
SM-CS	115	294	6.6	16.6	-84	-65
IS-HL	14	44	0.8	2.6	-56	-44
IS-HE	400	1303	22.4	72.9	-64	-46
IS-UT	461	1463	28.1	85.9	-139	-91
IS-P&T	18	58	1.0	3.3	-65	-46
UP-Fuel	65	170	4.0	10.6	-56	-45
UP-HE	99	260	6.1	16.2	-25	-21
UP-EM	36	94	2.4	6.1	-43	-34
UP-P&T	43	113	3.0	7.5	-44	-35
UP-CS	56	149	3.8	9.7	-45	-36

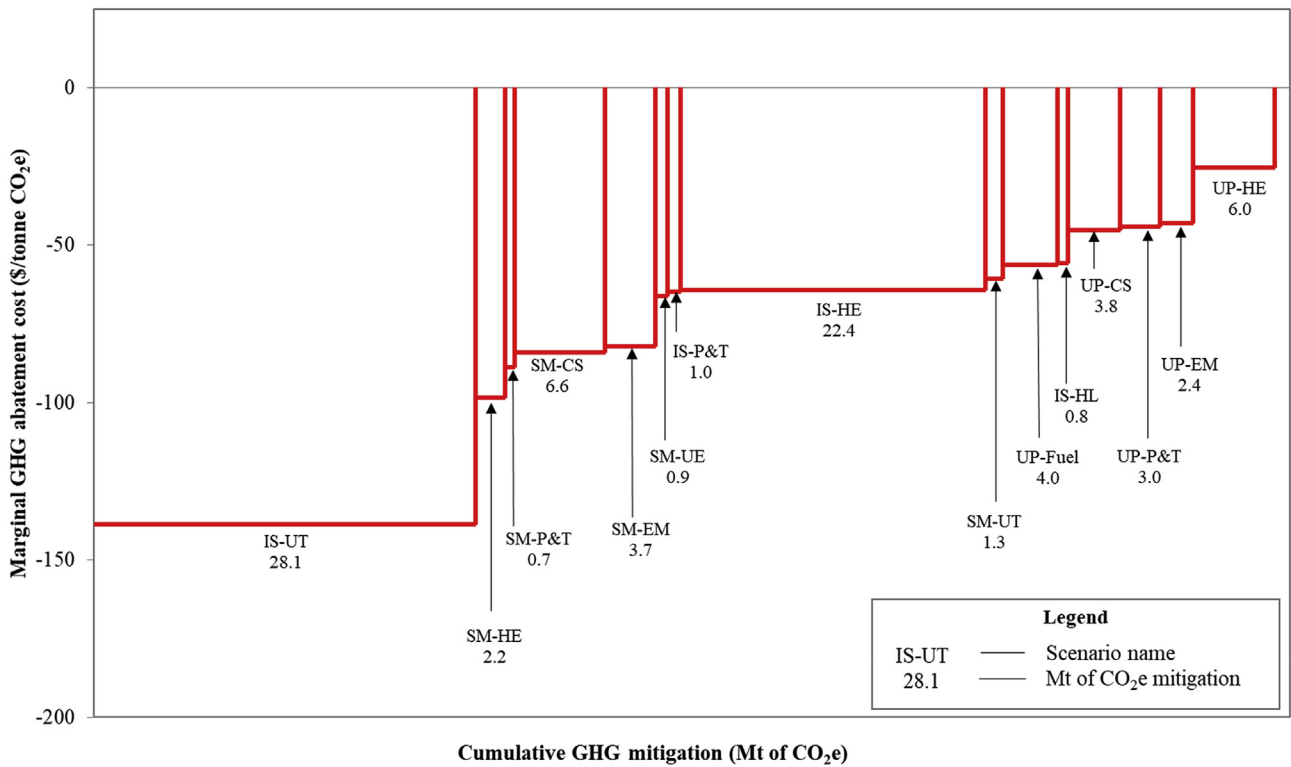
the 2050 (the years 2018–2050) and the 2030 (the years 2018–2030) scenarios, respectively. The horizontal axes show the GHG emissions reductions achievable and the vertical axes represent the marginal costs associated with each energy improvement option. The negative marginal GHG abatement costs indicate that the scenarios evaluated in this work have net cost savings.

In the surface mining sector, the best scenario in terms of reducing GHGs is the control systems scenario, SM-CS, with a marginal GHG abatement cost of -\$65/tonne of CO<sub>2</sub>e and a maximum GHG mitigation potential of 16.6 million tonnes (Mt) of CO<sub>2</sub>e for the study period ending in 2050. In in situ oil sands mining, the best scenario options for GHG mitigation potential are the heat exchange and integration scenario (IS-HE) and the utilities scenario (IS-UT) with possible GHG reductions of 72.9 Mt and 85.9 Mt, respectively, by 2050. The marginal GHG abatement costs are -\$46/tonne of CO<sub>2</sub>e and -\$91/tonne of CO<sub>2</sub>e, respectively. In the upgrading sector, fuel type and use (UP-Fuel) and heat exchanger/integration and fired heater efficiency (UP-HE) are the best scenario options in terms of GHG mitigation potential. The mitigation



Based on NPV of Costs in 2016 CAD\$

Fig. 3. Canadian oil sands marginal GHG emission abatement cost curve for the study period 2018–2050.



Based on NPV of Costs in 2016 CAD\$

Fig. 4. Canadian oil sands marginal GHG emission abatement cost curve for the study period 2018–2030.

potential and marginal GHG abatement costs for the UP-Fuel and UP-HE scenarios are 10.6 Mt and 16.2 Mt, respectively, and  $-\$45/\text{tonne}$  of  $\text{CO}_2\text{e}$  and  $-\$21/\text{tonne}$  of  $\text{CO}_2\text{e}$ , respectively, by the year 2050.

Overall, the cumulative GHG mitigation potential for all scenarios was in the range of 1.8–85.9 Mt by the year 2050, and implementing the in situ – utilities and in situ – heat exchanger/integration and fired heater efficiency options will have the best GHG mitigation potential. The amount of emissions charged the carbon price ranged from 0% to 26%, 19%–46%, and 19%–20% for the scenarios in surface mining, in situ mining, and upgrading, respectively between 2018 and 2050. It should be noted that it is feasible for all scenarios to be carried out concurrently. Implementing all the scenarios could reduce both the cumulative energy use and GHG emissions of the oil sands sector by 8% and 7%, respectively, at an average marginal cost of  $-\$62/\text{tonne}$  of  $\text{CO}_2\text{e}$  by the year 2050. The 2018–2030 marginal GHG abatement cost curve shows similar comparative results to the 2050 curve and so the same conclusions can be drawn. The only differences are that marginal mitigation potential and costs savings are lower because there is less time for the energy reductions to accrue benefit.

In the reference scenario, the oil sands GHG emissions in 2050 are expected to be 4 times the 2007 level. Given the environmental pressure on this sector to reduce its GHG emissions, strategies that can reduce both costs and GHG emissions should be adopted. The results of this study show that implementing the assessed energy-reduction measures increase the environmental performance at no additional cost in the short term (after 5 years) and have a significant impact on emissions – up to 7% reduction in emissions by 2050 was found to be possible if these strategies have not yet been implemented. The marginal GHG abatement cost curves presented can be used by decision-makers to formulate strategies to both save costs and reduce emissions. The results suggest that in situ oil sands energy-use reduction operations should consider improvements that can produce utilities more efficiently and improve their heat exchange networks and heater efficiencies to achieve maximum mitigation and return on investment. The surface mining control system and upgrading heat exchange scenarios have similar mitigation potential, but the former has higher marginal GHG abatement cost savings and should be considered initially.

### 3.3. Sensitivity analysis

Capital cost and discount rate vary with the facility. In addition, industrial end-use energy prices of natural gas and electricity are volatile. The production forecast considered for the reference scenario and the energy savings potential (energy intensities) can change. Therefore, a sensitivity analysis was done for a range of variables – capital cost, discount rate, energy intensity, natural gas price, electricity price, reference production growth, and electricity grid emission intensity factors – to understand how they impact the marginal GHG abatement cost. Figs. 1–21 in the supplementary file show the sensitivity of the marginal GHG abatement cost/savings to these variables for each scenario. The discount rate, energy intensity, and grid emission intensity factors were varied from 3.5% to 6.5%,  $-3\%$  to  $+3\%$ , and  $-50\%$  to  $+50\%$ , respectively. All the other variables are changed from  $-30\%$  to  $+30\%$  of the reference scenario value.

The discount rate, natural gas price, and energy intensity have a greater impact on marginal GHG abatement cost/savings than do other variables. The marginal GHG abatement cost/savings were  $-17\%$  to  $+28\%$  and  $-39\%$  to  $+44\%$  for the range of discount rates and natural gas prices, respectively. The electricity price change changed the results from  $-12\%$  to  $11\%$ . Some scenarios are not sensitive to the electricity price change as the energy savings

are only due to natural gas and produced gas. When capital cost is reduced by 30%, the UP-HE scenario shows the highest change in abatement savings (19%); the savings in the SM-EM, SM-HE, SM-CS, UP-Fuel, UP-EM, UP-P&T, and UP-CS scenarios increased by less than 2%. A change in reference scenario growth by  $-30\%$  resulted in marginal GHG abatement cost/savings change of only  $-1\%$ – $2\%$ . This small savings occurs because a change in production growth will change both the costs and the emissions, which nullify each other, keeping the marginal GHG abatement cost/savings almost constant. Given that the energy saving potential of the scenarios is from 0.05% to 5.91%, as shown in Table 5, the abatement savings do not exist for certain scenarios with low energy savings potential if there is an increase in energy intensity. For a 3% reduction in energy intensity, the marginal GHG abatement cost varied by  $-25\%$  to  $-10\%$ ,  $-27\%$  to  $-12\%$ , and  $-4\%$ – $2\%$  for the scenarios in surface mining, in situ mining, and upgrading, respectively. We have limited the sensitivity plots for the energy intensity variable to show only increases in energy intensity that will achieve a GHG reduction. The sensitivity analysis of GHG mitigation to changing reference scenario growth is shown in Figs. 22–24 in the supplementary data file. The mitigation potential of each scenario varied in proportion to the amount of growth change. The marginal GHG abatement cost and GHG mitigation varied from  $-4\%$  to  $+5\%$  and  $-6\%$  to  $+5\%$ , respectively, with a grid emission intensity factor change of  $-50\%$  to  $+50\%$  for all the scenarios (see Figs. 19–21 and 25–27 in the supplementary file).

### 3.4. Limitations

This study assumes constant energy intensities and thus an implied consistent future reservoir quality. If reservoir quality significantly decreases, more GHG emissions mitigation and marginal costs savings would be possible with the energy-demand reduction options than what is presented.

The extent to which some of the energy reductions might be implemented is not known. Therefore, the total GHG emissions mitigation results represent the ultimate potential if none were implemented currently. Nonetheless, decision-makers can use this information to select appropriate options knowing what has been implemented and what has not.

The GHG mitigation strategies covered here are limited to energy-demand reduction options. Alternative energy supply and production methods should also be investigated with this framework to give a more comprehensive assessment of GHG mitigation potential and marginal abatement costs over the long term. Further, the energy demand-reduction scenarios evaluated in this study do not cover all possible options, only those limited to investments that have a capital and operational improvement payback period of less than 5 years.

Oil sands extraction methods may be applied to unconventional oil extraction in other parts of the world (Jeff et al., 2009; Matthew, 2018). The modelling approach used in this study can be applied to other jurisdictions by varying the production volumes and shares of processes used. However, the efficacy of the model may vary depending on the reservoir characteristics and the associated energy intensities. The energy intensities presented here are based on current average conditions in the oil sands of Alberta, Canada. As reservoir quality changes, energy-use intensities may decrease or increase correspondingly. This will have an impact on the GHG mitigation potential of each scenario and so the energy intensities should be adjusted accordingly if these methods are applied to other locations.

Lastly, there may be barriers to technology implementation. The analysis does not consider barriers or penetration rates under different policy assumptions. Rather, the analysis shows the

comparative effectiveness of the options analyzed.

#### 4. Conclusion

This study evaluated energy demand-based greenhouse gas mitigation options for Canada's oil sands. A novel bottom-up energy demand-supply model of the oil sands was developed to perform a techno-economic-environmental evaluation of energy demand-reduction scenarios. Thirty different greenhouse gas mitigation scenarios were assessed to find greenhouse gas mitigation potential, marginal mitigation costs, and energy savings potential.

We have identified the energy-demand reduction strategies that offer the most cost-effective GHG mitigation in the oil sands sector. In situ extraction was found to have 65% of the evaluated cumulative greenhouse gas mitigation potential; upgrading and surface mining have 20% and 15%, respectively. In situ heat exchanger and utility-based improvements in particular have the highest greenhouse gas emission mitigation potentials of 72.9 and 85.9 million tonnes at cost savings of 46 and 91 \$/tonne of CO<sub>2e</sub>, respectively, by 2050. This indicates that if these improvements have not been made, doing so will be highly effective both in reducing the greenhouse gas footprint of in situ extraction and in lowering the production costs. The other improvement options also offer cost savings; however, they have less GHG mitigation potential.

We found that cumulative energy consumption and greenhouse gas emissions in the oil sands could be reduced by 8% and 7%, respectively, by 2050, an average annual greenhouse gas mitigation of 7.6 million tonnes. These are important findings since the oil sands sector is under international scrutiny for employing highly emission intensive processes and is expected to experience significant growth in the long term, thus compromising the effectiveness of climate change action. Since these improvements yield net cost savings, implementing them would be both environmentally and economically beneficial. It was found that varying key inputs, such as natural gas price, did not cause any scenarios to have net cost above zero, indicating that the cost savings are robust in each subsector. Decision-makers in both industry and government can use this study to support cost-saving and environmental initiatives simultaneously.

#### Acknowledgements

We thank the NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair in Energy and Environmental Systems Engineering and the Cenovus Energy Endowed Chair in Environmental Engineering for providing financial support and feedback for this project. As a part of the University of Alberta's Future Energy Systems research initiative, this research was made possible in part thanks to funding from the Canada First Research Excellence Fund. The authors are thankful to Alberta Innovates (earlier called as Alberta Innovates - Energy and Environmental Solutions) for the financial assistance for this project and to members of the Alberta Department of Energy and Alberta Environment and Parks for providing valuable input during the research. A report based on this research was submitted to Alberta Innovates. The authors are also grateful to Mrs. Astrid Blodgett for editing this paper.

#### Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.jclepro.2019.118306>.

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