Energy consumption and greenhouse gas emissions in the recovery and extraction of crude bitumen from Canada's oil sands

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ABSTRACT:

A model- FUNNEL-GHG-OS (**FUN**damental E**N**gineering Principl**E**s- based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in the **O**il **S**ands) was developed to estimate project-specific energy consumption and greenhouse gas emissions (GHGs) in major recovery and extraction processes in the oil sands, namely surface mining and in situ production. This model estimates consumption of diesel (4.4-7.1 MJ/GJ of bitumen), natural gas (52.7-86.4 MJ/GJ of bitumen) and electricity (1.8- 2.1 kWh/GJ of bitumen) as fuels in surface mining. The model also estimates the consumption of natural gas (123-462.7 MJ/GJ of bitumen) and electricity (1.2-3.5 kWh/GJ of bitumen) in steam assisted gravity drainage (SAGD), based on fundamental engineering principles. Cogeneration in the oil sands, with excess electricity exported to Alberta's grid, was also explored. Natural gas consumption forms a major portion of the total energy consumption in surface mining and SAGD and thus is a main contributor to GHG emissions. Emissions in surface mining and SAGD range from 4.4 to 7.4 gCO_2eq/MJ of bitumen and 8.0 to 34.0

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gCO_2eq/MJ of bitumen, respectively, representing a wide range of variability in oil sands projects. Depending upon the cogeneration technology and the efficiency of the process, emissions in oil sands recovery and extraction can be reduced by 16-25% in surface mining and 33-48% in SAGD. Further, a sensitivity analysis was performed to determine the effects of key parameters on the GHG emissions in surface mining and SAGD. Temperature and the consumption of warm water in surface mining and the steam-to-oil ratio (SOR) in SAGD are major parameters affecting GHG emissions. The developed model can predict the energy consumption and emissions for surface mining and SAGD for oil sands.

Keywords:

Life cycle assessment, energy consumption, GHG emissions, oil sands, surface mining, SAGD

1. Introduction

With the increase in global energy demand and limited conventional oil resources, focus has shifted towards unconventional oil resources, such as the oil sands in western Canada. The oil sands in Alberta, with 170.2 billion barrels, are the third largest proven oil reserves in world after Saudi Arabia and Venezuela [1]. As of 2012, Alberta produced 1.9 million barrels per day of raw bitumen; this figure is projected to increase to 3.8 million barrels per day by 2022 [2]. Bitumen from the oil sands is highly viscous at reservoir conditions and deficient in hydrogen [3] and therefore requires more energy for recovery, extraction, and processing into refined products than do conventional oil resources [4].

In contrast to this increased production from unconventional oil resources, regulations such as the Low Carbon Fuel Standard (LCFS) and the European Fuel Quality Directive have demanded a 10% reduction in life cycle greenhouse gas (GHG) emissions from transportation fuels by 2020 [5, 6]. The regulations call for appropriate quantification and assessment of life cycle GHG emissions from these oil resources. Moreover, technology in the oil sands is still in the development stage and focuses on improving profitability and reducing the carbon footprint of oil sands-derived fuels. So it is necessary to benchmark life cycle GHG emissions from oil sands technologies to see if the desired targets are being met.

With the technologies available today, bitumen from the oil sands is produced through surface mining and in situ recovery. Surface mining is possible for shallow mines within a 0.4-1.4 stripping ratio (ratio of overburden thickness, which is 30 m or less, to oil sands ore thickness), with a typical ore thickness of 90 m [7]. Oil sands ore is mined using shovels and trucks and then transported to extraction facilities where bitumen is separated from the ore with warm water. Deeper oil sands ores are recovered using in situ techniques, which comprise a single wellbore for steam injection and oil production, called Cyclic Steam Stimulation (CSS), and two wellbores for continuous steam injection and bitumen production, called Steam Assisted Gravity Drainage (SAGD). In 2012, total in situ production accounted for 52% of the total crude bitumen production remaining from surface mining [8]. The bitumen produced from surface mining and SAGD is mixed with a diluent (naphtha or natural gas based condensate)for transportation to an upgrader (to produce synthetic crude oil [SCO], a refinery feedstock) or to the refinery directly. In 2012, all crude bitumen produced from mining and a small portion (about 7%) of bitumen produced from in situ was upgraded to SCO and yielded 329 million barrels of upgraded bitumen [2]. Upgraded bitumen formed 52% of the total crude bitumen in 2012 [2].

There are a few life cycle assessments (LCAs) of oil sands-derived fuels. Contributions in this field have been made from both academics and consultants. Two studies [9, 10], contracted by the Alberta government, present recovery, extraction, and transportation emissions from conventional and non-conventional crudes and perform a comparative analysis of the production of transportation fuels in the U.S. However, these studies do not calculate project-specific emissions based on technical parameters such as reservoir and product properties. Ordorica-Garcia et al. [11] and Betancourt-Torcat et al. [12] focus on optimizing the costs for energy demands in oil sand industry. Similarly [13-15] and [16] study the carbon reduction technologies from economic aspect but do not detail the estimation of GHG emissions from specific oil sand projects. Other studies [17-19] answer different questions and do not suffice for calculating project-specific energy consumption and emissions. None of these studies give access to the operating parameters. The default parameters cannot be modified to evaluate emissions for a different project.

A few LCA models do incorporate the oil sands' recovery and extraction pathways. The most well-known are GHGenius [20] and GREET [21], maintained by Natural Resources Canada and Argonne National Laboratory, respectively. The user can construct oil sands pathways within these models by either using default values or user-input data. However, there is no method in these models to estimate the specific energy consumption in any of the unit operations. Moreover, GHGenius and GREET present different LCA results due to differences in default input energy assumptions and different methodologies. Due to these variations and unavailability of specific data for energy consumption, the authors felt the need to develop a model that would estimate energy consumption based on various technical parameters.

Charpentier et al. [22] reviewed 13 reports and studies, including the models mentioned above, and found inconsistencies in the results reported due to variations in system boundaries, data quality, methods, and documentation. The authors proposed depicting life cycle emissions as ranges rather than point estimates, depending on actual performance data. The authors also called for additional research for better characterization of oil sands technologies and pathways. Brandt [23] performed a comparative analysis of GHG emissions in each unit operation in the oil sands as reported by GREET, GHGenius, and industrial consultancy reports. Charpentier et al. [22] and Brandt [23] recommended the use of GHGenius for the life cycle assessment of fuel derived from the oil sands. The authors infer that GHGenius has most comprehensive oil sand pathways and better representation of average industry values for energy consumption in oil sands. Brandt suggested further research towards modeling the emissions of process-specific configurations. Bergerson et al. [24] documents the development of GHOST, a life cycle assessment model for oil sands-derived pathways. GHOST is based on confidential data from industry on energy consumption from a set of operating projects. GHOST calculates GHG emissions based on these confidential data from a particular set of projects; the results are therefore specific to those projects. GHOST does not have any method to calculate project-specific energy consumption and GHG emissions in the recovery and extraction processes of oil sands.   There is scarcity of research in estimation of the life cycle emissions and energy consumption for surface mining and

SAGD operations for oil sands through development of theoretical engineering models. The developed models in this paper are aimed at addressing these gaps.

The objective of this research is to estimate the life cycle GHG emissions and net energy consumption from surface mining and SAGD operations of oil sands through development of fundamental engineering based models. In addition to this, the aim of this paper is also to address the gaps in the knowledge in this area through a comparative analysis of few studies done in GHG emissions from surface mining and SAGD operations.

This paper presents a detailed and data-intensive technical model named FUNNEL-GHG-OS (**FUN**damental E**N**gineering Principl**E**s- based Mode**L** for Estimation of **G**reen**H**ouse **G**ases in the **O**il **S**ands) based on basic engineering equations that calculate the energy consumption and related life cycle GHG emissions for process- and project-specific operations. This user-friendly spreadsheet model allows the user either to use the default parameters or input user data. In this research a technical model is developed to estimate the carbon dioxide equivalent gas emitted per m^3 of bitumen mined and extracted. Further, this model was used to estimate the energy consumption and GHG emissions in recovery and extraction processes used in the oil sands, namely surface mining and steam assisted gravity drainage (SAGD), while other operations such as CSS and CHOPS (cold heavy oil production with sand) are outside the scope of this research. The GHG emissions reported for the unit operations include 1) direct emissions from the combustion of fuel on site and 2) upstream emissions associated with recovery, processing, and transportation of these fuels. The paper also includes the emissions from crude bitumen batteries and those from flaring of produced gas in SAGD projects but does not include the equipment, and land-use emissions. Land-use emissions range from 0.8- 10.2 gCO_2eq/MJ of refinery feedstock in surface mining and less than 0.4 gCO_2eq/MJ in in-situ production of oil sands [25].

The functional unit used for a life cycle assessment of oil sands-derived fuels is one MJ (along with one m^3) of bitumen produced in surface mining or SAGD. The metric used for presenting the life cycle GHG emissions is gCO_2eq/MJ of bitumen. The emissions also include the effects of other GHGs such as CH_4 and N_2O. However, the results are also presented in gCO_2eq per m^3 of bitumen produced from surface mining or SAGD unit operation. The lower heating value (LHV) of bitumen (to be consistent with the California GREET model) has been used to define the energy content of bitumen (API- 8). LHV of the fuels is used for reporting the energy consumption and associated GHG emissions. Necessary unit conversions are made to present and compare the results with other studies.

2. Methodology

2.1 Surface Mining

The surface mining operation commences with the removal of layers of overburden (rock, sand, and clay) with shovels and trucks. The main energy input in this stage is the diesel fuel used by the shovels and trucks. Step-by-step basic engineering calculations are performed to estimate the diesel consumption per m^3 of bitumen mined.

The first step in FUNNEL-GHG-OS model development is to identify the fleet of shovels and trucks used in oil sands projects. The parameters for this fleet can either be user defined or defaults in the model. The fleet considered in this study and its specific fuel consumption per hour was taken from an earlier study [26]. The next step is the calculation of the productivity of the shovels and trucks. The methodology followed in this model (shown in Figure 1) is the standard calculation methodology for general surface mining operations [27]. Oil sands ores are characterized by many parameters. Those most useful here in the calculation of shovel productivity are oil sands ore grade (that is, bitumen saturation, with ranges from 6.8 to 12.2% [28-31]), oil sands density, and swell factor. The model's oil sands ore grade default is 11.24% , which is an production weighted average from various surface mining projects undertaken by six major surface mining companies from 2009- 2012 [32].

Parameters such as rated payload and cycle time, which are specific to the type and model of the shovel used in the oil sands, are taken from the individual company brochure for that particular type of shovel. The shovel's bucket capacity is based on the material density of the oil sands ore. Further, previously gathered data are used to estimate diesel consumption in shovels per m^3 of bitumen mined.

Truck productivity is based on the calculation of total cycle time. Total cycle time for trucks is the sum of spot and load, haul loaded, turn and dump, haul empty, wait, and delay times. Total cycle time depends on the loading equipment used, the payload capacity of the truck and the number of trucks in the fleet [27]. An average cycle time of 18.2 minutes [27] is selected for a fleet of five trucks. Using the gathered data for fuel consumption, diesel consumption in trucks per m^3 of bitumen mined is calculated.

The mined ore is crushed through double roll crushers and rotary breakers and then sieved through vibrating screens. The material passing through screens is mixed with warm water and transported through a conditioning pipeline to extraction facilities. Operating slurry temperatures range from 35 ˚C to 75 ˚C [33, 34]. Typical operating temperature of slurry mixtures in pipelines is 40-50 ˚C [28, 35]. At extraction facilities, bitumen froth (60% + bitumen; the remainder is water) [36] is separated from sand in separation vessels. The amount of hot water consumed per m^3 of bitumen ranges from 6 to 9 m^3 depending on the grade of the oil sands ore [26, 28, 37].

Figure 1.

The main energy input in extraction is natural gas, which is required to heat water and for electricity used to drive pumps and floatation vessels. The FUNNEL-GHG-OS model determines the amount of natural gas required to generate warm water based on heat and mass balance principles. The input parameters for this module are given in Table 1. The amount of natural gas required depends on the process conditions of the steam. The steam used in surface mining is generated at 400 ˚C and 7 MPa [26, 34]. Because of the huge steam requirement and the simultaneous requirement of electricity, all existing oil sands mines have cogeneration facilities [38]. As of 2013, the power demand for mining projects is 1100 MW whereas the installed co-generating capacity of mining projects 1200 MW. By 2022, the installed cogenerating capacity is expected by 100% as opposed to 82% in the power demand [39]. In view of current industry practices, this model incorporates all the options of cogeneration.

Table 1.

The FUNNEL-GHG-OS model considers three different cogeneration scenarios in surface mining operations.

Mining NO Cogen: No cogeneration – a stand-alone operation for on-site steam generation using a natural gas-fired industrial boiler and electricity purchased from Alberta's grid. In this case, the model estimates the natural gas required to generate the steam that in turn heats the process water. The electricity demand for the plant is satisfied by electricity imported from Alberta's grid, which is mainly coal- and natural gas-based [41].

Mining ST Cogen: Cogeneration using a steam turbine – an integrated operation for on-site steam generation using a natural gas-fired industrial boiler and on-site electricity generation using a steam turbine. The exhaust from the steam turbine undergoes a temperature change in a heat exchanger that heats the process water. The heat exchanger was designed for 1 MPa of saturated steam [34]. The model calculates i) natural gas required and ii) electricity generated in this cogeneration cycle.

Mining GT Cogen: Cogeneration using a gas turbine – an integrated operation for on-site steam generation using a natural gas-fired industrial boiler and on-site electricity generation using a gas turbine. The fuel for the turbine is natural gas. The exhaust from the turbine is at a high temperature of 450-500 ˚C [42]. The mass of exhaust is estimated using a stoichiometric combustion equation [43]. The waste heat energy in the exhaust is recovered in the heat recovery steam generator (HRSG). 55% of the heat in the exhaust is recovered in HRSG [44]. The exhaust energy may or may not be sufficient to heat process water. When there is insufficient exhaust energy, additional natural gas is fired into the HRSG. The model calculates through iterations i) the total natural gas required to heat process water and ii) the electricity generated in this cogeneration cycle.

The electricity consumed in the plant may be either generated on site or purchased from the grid. Apart from this, as electricity is cogenerated, the excess electricity is exported to the grid. Different emissions factors of on-site generated electricity and grid electricity make it mandatory to account for each kind of electricity individually. Due to the special nature of the equipment used in oil sands extraction [34], it is not possible to estimate electricity consumption through basic equations; therefore, the electricity required per m^3 of bitumen was estimated from literature findings and actual data reported by industry to the Energy Resources Conservation Board (ERCB) [45], now the Alberta Energy Regulator, a regulatory body of the Alberta government. Only two oil sands companies have reported data for their stand-alone mining projects [20]. The values used in this model are calculated from the data reported by these companies over three years, 2010-2012. The model predicts the electricity exported to the grid in each of the cogeneration cases. It has been assumed that the grid infrastructure already exists to take the extra load of electricity export from oil sands.

2.2 Steam Assisted Gravity Drainage (SAGD)

In the SAGD process, a pair of horizontal wellbores or pipes (an injector and a producer), is drilled into oil sands, 80-1000 meters deep [46, 47], depending on the reservoir. Steam is injected from above-surface facilities into the injector, then rises, condenses, and washes the hot bitumen along with condensed water into the producer well that is 3-5 m below the injector well. The hot bitumen-water mixture is pumped to the surface where it is separated. Because the density of bitumen and water are not very different, a diluent, usually naphtha or natural gas condensate, is added to facilitate this separation. Diluent mixes with bitumen to increase the American Petroleum Institute (API) gravity of the mixture and thus ease the separation. The water is treated so that it can be used again to produce steam. A detailed schematic of the process is shown in Figure 2.

Figure 2.

Natural gas is required to generate steam in the process, and electricity is required to drive basic equipment, such as the pumps and the evaporator. The FUNNEL-GHG-OS model calculates the amount of natural gas and electricity consumption in SAGD unit operations.

Natural gas consumption is calculated based on 1) the steam-to-oil ratio (SOR), 2) the process conditions for steam (temperature, pressure, and quality of steam generated), 3) the amount of produced gas, 4) the boiler feed water temperature, and 5) the efficiency of the system equipment. The user can either enter the parameters for specific projects or use the default values in the model. The SOR is a single metric that defines the efficiency of the operation. The SOR can be expressed as a cumulative steam-to oil-ratio (cSOR) or an instantaneous steam-to-oil ratio (iSOR). The cSOR is a measure of the average volume of steam required to produce one unit volume of bitumen over the entire life of project, whereas the iSOR is a measure of the instantaneous or current rate of steam. The SOR may change depending upon the current stage of the project. For an individual well pair, the SOR is high at the start of the project, decreases sharply during the initial months of production, stabilizes in 12 to 18 months [4, 48], and then declines slightly as the project proceeds towards maturity [48]. The model built is flexible enough to asses both of these options.

The FUNNEL-GHG-OS model uses a default iSOR of 2.89, which is the production weighted average over the last three years, though this figure has varied from 2.1 to 6.54 [49]. Some projects do have higher iSOR that last for small time but 87% of the bitumen production over the last three years has occurred in the iSOR range of 2.06 to 3.20. The majority of the projects operate at the lower end of the SOR range. Conditions at which the steam is generated in oil sands are project specific and range from 3.5 to 8.9 MPa with steam quality varying from 65% to 98%. The default steam condition used in a SAGD operation is 8 MPa [26] with a steam quality of 80% [44]. Further the variation of these factors is studied in sensitivity analysis in section 3.3.2.

The model explores two different cogeneration scenarios in SAGD operations.

SAGD NO Cogen: No cogeneration – a stand-alone operation for on-site steam generation using a natural gas-fired industrial boiler and electricity purchased from Alberta's grid.

SAGD GT Cogen: Cogeneration using a gas turbine – an integrated operation for on-site steam generation using a natural gas-fired industrial boiler and on-site electricity generated with a gas turbine.

The methodology for cogeneration is detailed in section 2.1. Almost all SAGD operations that employ cogeneration, use gas turbines [42], hence the use of a steam turbine for cogeneration was not explored. As of 2013, the cogenerating capacity of in-situ oil sand projects was 800 MW against their electric demand of 600 MW. By 2022, the cogenerating capacity is anticipated to be 3900 MW against the power demand of 3200 MW [39]. The natural gas consumed in the process also depends on the amount of co-produced gas. Produced gas in SAGD ranges from 1 to 89 m^3/m^3 of bitumen [44, 49, 50]. Most of the produced gas is conserved and utilized so as to reduce the natural gas demand of the plant while a portion of it is flared. Based on production weighted average of produced gas consumption and flaring data [49, 50], a default value 13.1 m^3/m^3 is utilized for consumption of produced gas and 7.4 m^3/m^3 for flaring of produced gas in SAGD plants. The GHG emissions from crude bitumen batteries (emissions from bitumen storage systems) are taken into account and an average of five years (2007-11) has been obtained from [50]. The energy content of co-produced gas varies widely depending on the composition of the produced gas and can be one-third to equal of the energy content of natural gas [44, 51, 52]. The default value assumes the energy content of co-produced gas similar to that of natural gas and sensitivity to the composition of produced gas is presented in section 3.3

The other fuel consumed in SAGD is electricity, which powers pumps, evaporators, and other equipment. The original SAGD operations used gas lift technique to lift fluids, mainly bitumen and condensed water, to the surface. These days, electrical submersible pumps (ESPs) are used. This change has resulted in a lower SAGD operating pressure, thus lowering steam losses and energy use and improving the SOR [48]. The model developed for this study explores both gas lifts and ESPs. The electricity consumption to drive the ESPs is calculated using reservoir characteristics (reservoir temperature, bottomhole pressure), operating parameters (wellhead pressure, horizontal and vertical well depth, diameter of production well), and bitumen properties (viscosity, API). These parameters can be entered by the user, and default values are provided based on data from the literature. The parameters are detailed in Table 2. Pumping power is based on the pressure gradient between the bottomhole pressure and wellhead pressure. This pressure gradient is quantified using head loss due to elevation and friction, which is further based on parameters such as the Reynolds number, relative roughness, diameter of the production well, and velocity. In the gas lift technique, the gas used is either the gas produced along with the bitumen, air, or natural gas. The main source of energy consumption in the gas lift technique is the electricity consumed by the compressor. Compressor power was estimated using basic engineering equations for power calculation. The major consumer of electricity is the evaporator, which is used for water treatment. The recycled water, or make-up water, needs to be treated before it can be used for steam production. Electricity consumption in evaporators was estimated using proved correlations. Evaporator power depends upon the vapor mass flow rate, the rise in temperature in the compressor, and a constant that depends on the size of evaporator [53].

Table 2.

3. Results and Discussion

3.1 Surface Mining

The diesel consumption calculated by the FUNNEL-GHG-OS model is in the range of 5-8 L/m^3 of bitumen mined, depending upon the technical parameters and conditions. The fuel used by trucks is a major portion of the total diesel fuel consumed in surface mining unit operations.

The electricity consumed in this unit operation is in the range of 72 kWh to 85 kWh (default value – 80.4 kWh) per m^3 of bitumen mined. In the "no cogeneration" case, all the electricity is purchased from Alberta's grid. For cogeneration projects, electricity is generated on site using natural gas. In some companies' projects, apart from on-site electricity generation, some electricity is purchased from the grid. The grid electricity consumption amounts to 10-20% of the total electricity consumed [45]. The option of using grid electricity along with cogeneration (which is specific to certain projects due to their location) is also explored. The figures in the literature for electricity consumption in surface mining unit operations vary widely. Bergerson et al. reports 50-100 kWh of electricity consumption per m^3 bitumen [24]. A feasibility study of a stand-alone surface mining project estimates 34 kWh of electricity consumption per m^3 of bitumen [34].

In the absence of cogeneration (Mining NO Cogen), the model calculates that 64 m^3- 90 m^3 (default value – 75 m^3) of natural gas is consumed per cubic meter of bitumen mined. In the case of cogeneration with a steam turbine (Mining ST Cogen), 75 m^3 to 105 m^3 (default value – 87.4 m^3) is consumed, depending on the process conditions and efficiency of the process. While natural gas consumption increases in the cogeneration case, electricity is cogenerated. The electricity cogenerated is 53 kWh to 74 kWh (default value – 61.8 kWh) per m^3 of bitumen. In Mining GT Cogen, 78 m^3 to 95 m^3 (default value - 87.3 m^3) of natural gas is consumed, whereas 79 kWh to 140 kWh (default value – 107.3 kWh) of electricity is generated per cubic meter of bitumen mined. Of all the electricity produced on site, a major portion is used to fulfill the electricity demands of the plant and the remaining portion offsets the grid electricity.

Emissions factors for diesel and natural gas equipment used to calculate GHG emissions are imported from the GREET model (version 4.02a) [21]. These factors include both combustion and upstream emissions. Upstream emissions are those associated with recovery, transport, and processing of fuel. 17% of the total diesel emissions come from the upstream emissions of diesel (recovery, transportation, refining etc.). This value drops to 9% in the case of natural gas. An emissions factor of 880 grams of carbon dioxide equivalent per kWh of Alberta's grid electricity used has been used [40, 44, 60, 61]. The surplus electricity that is generated on site using a much cleaner fuel – natural gas – is exported to the coal-based grid. The method used to calculate the associated emissions can greatly affect the emissions figure for the overall project. In the case of cogeneration, where excess electricity is exported to the grid, an emissions factor of 650 grams of carbon dioxide equivalent per kWh of displaced grid electricity is used. The emissions factor used is as per the memorandum issued by the Climate Change Secretariat, Government of Alberta [62].

The GHG emissions associated with recovery and extraction in surface mining operations are presented in Table 3. The table shows the type and quantity of fuel mix in surface mining. The range of values depicts the variation in surface mining projects, the ore grade, and the technology used.

Table 3.

Figure 3.

The emissions from surface mining unit operations range from 180 kg to 302 kg CO_2 equivalent per cubic meter of bitumen mined (4.4-7.4 gCO_2eq/MJ of bitumen), depending upon the process conditions, ore grade, cogeneration scenario, and technology used. Emissions are highest in the "no cogeneration" case (Mining NO Cogen) – 230 kg- 302 kg/m^3 (5.64-7.4 gCO_2eq/MJ of bitumen) as shown in Table 3. Cogeneration technology with gas turbines can reduce emissions more, as these export more electricity to grid than do steam turbines. Emissions in this case are reduced by 12-30%. Emissions from diesel are a small part (approximately 10%) of total emissions in surface mining. Natural gas emissions (on-site combustion and upstream emissions from natural gas recovery, transportation, processing, etc.) form a major portion of total emissions – 65% in Mining NO Cogen to 98% in Mining GT Cogen. Alberta's grid electricity use accounts for 24-29% of the total emissions in Mining NO Cogen and 4-7% in Mining ST Cogen. This lower emission is because of cogeneration. Cogeneration satisfies the majority of plant demand. The remaining demand, which is satisfied by the import of grid electricity, accounts for 4-7% of total emissions. In Mining GT Cogen, the electricity emissions are negative, as shown in the Figure 3. Negative emissions signify the displacement of coal-based grid electricity by the much cleaner natural gas-generated electricity. Net emissions are lowered by 2% to 17%, hence net emissions in Mining GT Cogen range from 180 kg to 226 kg/m^3 of bitumen mined (4.4 – 5.4 gCO_2eq/MJ of bitumen).

Figure 3 presents emissions results from this research and compares it with those of previous literature and models. The results are in agreement and close in range to values predicted by earlier models and studies. The emissions for the "no cogeneration case" estimated from this research (257.9 kg/m^3 of bitumen) are in between the emissions reported by GREET (206.2 kg/m^3 of bitumen)[21] and Jacobs (297.54 kg/m^3 of bitumen)[10]. The variations in values reported in the existing literature are due to differences in boundary conditions, assumptions, technology evaluated, and fuel input. The GHGenius[20] model considers cogeneration in surface mining operations whereas the GREET model does not. Our research covers and presents results for cases without cogeneration and with cogeneration using steam or gas turbines. The range of emissions presented in this research is obtained using default values and sensitivity analysis, and lies within the broad range represented by GHOST [44].

3.2 SAGD

Specific energy consumption and emissions from each fuel input estimated by the FUNNEL-GHG-OS model are shown in Table 4. The natural gas consumption in the "no cogeneration" case (SAGD NO Cogen) varies from 150.3 to 468 (default value – 200.7) m^3/m^3 of bitumen, depending upon the steam-oil ratio and the efficiency of the process. Whereas the SOR varies from project to project and can be user specific, the model uses a default value of 2.89. With improvements in technology and with project maturity, oil sands companies have been able to achieve a SOR as low as 2.1 [49]. Natural gas consumption in the cogeneration case (SAGD GT Cogen) is higher, ranging from 277.5 to 562 m^3/m^3 of bitumen (default value – 322). Electricity consumed in evaporators form a significant portion of the plant's total electricity demand [51, 63, 64]. Industry personnel expect a relationship between instantaneous SOR and electric power consumption [44]. A linear relationship, as shown in Figure 4, is estimated for iSOR and electric power consumption. In [10], a similar kind of relationship was estimated with actual industrial SAGD data and the observation that evaporators are a major consumer of electric energy in SAGD operations. Power consumed by evaporators is correlated linearly to the amount of water treated for steam formation. Figure 4 shows a comparison of electricity estimated by this research to electricity consumption reported by major SAGD operators against the SOR of the projects [49, 50]. As can be observed, the electricity intensity estimated by this research is representative of electricity intensity reported by majority of SAGD operators. However deviation in some data points is because the electric consumption in certain projects is very specific to those projects due to their specific reservoir properties.

Figure 4.

Table 4.

Emissions in SAGD range from 561.9 to 1384 $kgCO_2eq/m^3$ of bitumen (13.8- 34.0 gCO_2eq/MJ of bitumen) in SAGD NO Cogen to 327 to 931 $kgCO_2eq/m^3$ of bitumen (8.0-22.9 gCO_2eq/MJ of bitumen) in SAGD GT Cogen. As shown in Figure 5, natural gas emissions are the main contributing emissions, 70% in the “no cogeneration” case. Electricity emissions comprise 6-20% (default value – 9%) of the total emissions in SAGD. The produced gas emissions from its consumption and flaring form a very small part of the total emissions in SAGD [44]. GHG emissions from crude bitumen batteries form a significant portion and amount to approx. 2.1 gCO2eq/MJ of bitumen [50].

Natural gas consumption increases with cogeneration and results in a 61% increase in natural gas emissions. However, the extra natural gas consumption lowers net emissions because electricity in excess to the plant’s demand is produced. This excess electricity displaces the GHG-intensive Alberta grid electricity. Hence the net emissions are reduced by 48%.

The SOR in industry is used to define the efficiency of SAGD operations. Improving the SOR from 2.89 to 2.1 leads to a 26% reduction in net emissions in SAGD NO Cogen. While this model incorporates the use of evaporators for water treatment, other methods such as warm lime softening may also be employed. GHG emissions from treating the produced water in evaporators are 7% to 8% higher than emissions from treating produced water in warm lime softening [65].

Figure 5.

As illustrated in Figure 5, the FUNNEL-GHG-OS model predicts emissions well within the ranges given in existing models, industry consultancy reports, and peer-evaluated studies. This model covers a large range of iSORs (2.1 to 6.54) and presents a wide range of emissions. GREET and GHGenius models do not consider cogeneration in their default fuel input, hence compare with the "no cogeneration case" in our research. The emissions estimated by GREET and GHGenius are higher (10% and 21%, respectively) than the default emissions in our research, but are covered in the broad range of emissions presented in our research. Jacobs [10] reports lower emissions in the cogeneration case than estimated by our research because of the use of 80% coal-based grid electricity for giving the credits for electricity export. The model predicts values well in the range of the GHOST model values.

3.3 Sensitivity Analysis

3.3.1 Surface Mining

An analysis of the sensitivity of various parameters was conducted to determine the effect of each parameter on net GHG emissions from the unit operations. The following key parameters were investigated: water temperature, water consumption, heat exchanger efficiency, boiler efficiency, diesel consumption, electricity consumption, and electricity emissions factors. The sensitivity corresponds to the base case with no cogeneration (Mining NO Cogen). As illustrated in Figure 6, the emissions in surface mining are highly sensitive to temperature and warm water consumption. Equally influential are the efficiency of the boiler and the heat exchanger. Diesel consumption, the electricity emissions factor, and electricity consumption have a relatively minute effect on net GHG emissions in surface mining because diesel consumption and electricity form a small portion (approximately 10% and 25%, respectively) of total surface mining emissions. Other parameters affect natural consumption, which accounts for around 65% of the total surface mining operations. Lowering water temperature to 35 ˚C from the 50 ˚C used today would result in 25% fewer emissions in surface mining. Approximately 42% more emissions are found in processes that use high temperatures (i.e., around 75 ˚C). Improvements in heat exchanger and boiler efficiency would result in less natural gas use and hence would reduce the total emissions in surface mining. However, because the boiler and heat exchanger technology has already matured, the scope of improvement in this technology is limited. Technology improvements that result in reduced warm water consumption would reduce surface mining emissions. A 10% reduction in the consumption of warm water would result in about a 7% reduction in surface mining emissions.

Figure 6.

3.3.2 SAGD

The sensitivity analysis of GHG emissions in SAGD unit operations was investigated in terms of quantity of steam, steam conditions, reservoir properties, and other technical parameters. The quantity of steam used is represented by the iSOR, whereas saturated pressure and the quality of the steam represent steam conditions. Reservoir considerations include produced gas, horizontal well depth, vertical well depth, bottomhole pressure, and wellhead pressure. Other important technical parameters are the efficiency of the boiler and the heat exchanger.

The iSOR and quality of steam used are the parameters to which GHG emissions are most sensitive. As shown in Figure 7, improving the iSOR from 2.89 to 2.1 (27.3% decrease) would result in a reduction in net emissions by 26%. A 10% decrease in the quality of steam at required conditions leads to 4.2% increase in consumption of natural gas, which leads to higher emissions. As can be seen from equation 15 in SI, decreasing quality of steam means more natural gas for producing the steam. But, lower quality of steam also means lower enthalpy in steam, leading to lower natural gas consumption. But the increase in natural gas consumption due to lower quality of steam is more than the decrease in natural gas consumption due to lower enthalpy, resulting in net increase in GHG emission. The amount of electricity consumed in the pumps or the compressor used in the case of the gas lift depends on parameters such as bottomhole pressure, wellhead pressure, vertical well depth, and horizontal well depth. These parameters have a small effect on the net emissions because electricity emissions are a small portion (about 9% in Mining NO Cogen) of total emissions in SAGD.

Produced gas in SAGD projects effects the net emissions minutely. Varying the quantity of produced gas within ±20% changes the net emission by ±2%. In the base case, the composition of produced gas is assumed to be same as natural gas[44] and it composition has been varied by changing the amount of methane and other hydrocarbons in produced gas. Decreasing the methane content by 20% and correspondingly increasing the other hydrocarbons in equal portions, increases the energy content of produced gas by 30% and emission factor of produced gas by 25%. These changes alter the net emission by less than 1%.

Figure 7.

3.4 Comparison with industry reported data

Figure 8 compares the average annual energy inputs in surface mining and SAGD unit operations, reported by industry to those estimated by this research. Different oil sands operators report monthly energy consumption data to Alberta Energy Regulator (AER) and these data have been obtained from [32, 50, 66]. The industrial reported data is converted to energy of fuels on LHV basis. The wide ranges of values reported by industry portray the variability of oil sand operations [22]. The industrial reported data is compared to range of energy results from this research that is obtained using the default input parameters and performing the sensitivity analysis as mentioned in section 3.3. The energy estimated by this research fairly agrees and lies in the range of values reported by the industry.

Figure 8.

Conclusions

Our research presents a data intensive theoretical model named FUNNEL-GHG-OS to estimate energy consumption, fuel mix, and emissions for each individual extraction and recovery project in the oil sands. The model predicts GHG emissions (4.4 to 7.4 gCO_2eq/MJ of bitumen in surface mining and 8.0 to 34.0 gCO_2eq/MJ of bitumen in SAGD) well in the range of existing models and literature. The model would help industry to make decisions to further reduce GHG emissions in each stage in the unit operations. Emissions in surface mining (excluding the fugitive emissions from tailings and land-use emissions) are lower than emissions from SAGD. Emissions in surface mining are sensitive to temperature and warm water consumption. Natural gas is the single largest energy source in both surface mining and SAGD unit operations. In SAGD, where the SOR is the single important factor affecting net emissions, reducing the SOR would mean greater efficiency and fewer GHG emissions. SOR of the project can be improved by the use of electric submersible pumps (ESP) that can handle high temperatures and thus eliminate the need of high pressure steam which is required in the case of gas lift [48, 50]. Improved understanding of reservoir characteristics to appropriately drill the wellbore and enhancements in the wellbore liners reduce the operational downtime and energy losses, thus improving the SOR. Addition of volatile solvent and the use of electromagnetic heating to a targeted zone in the reservoir are tested on pilot scale, thus significantly enhance oil production and lower steam requirement [67-69]. Cogeneration has the potential to lower the net environmental impact of oil sands activities.

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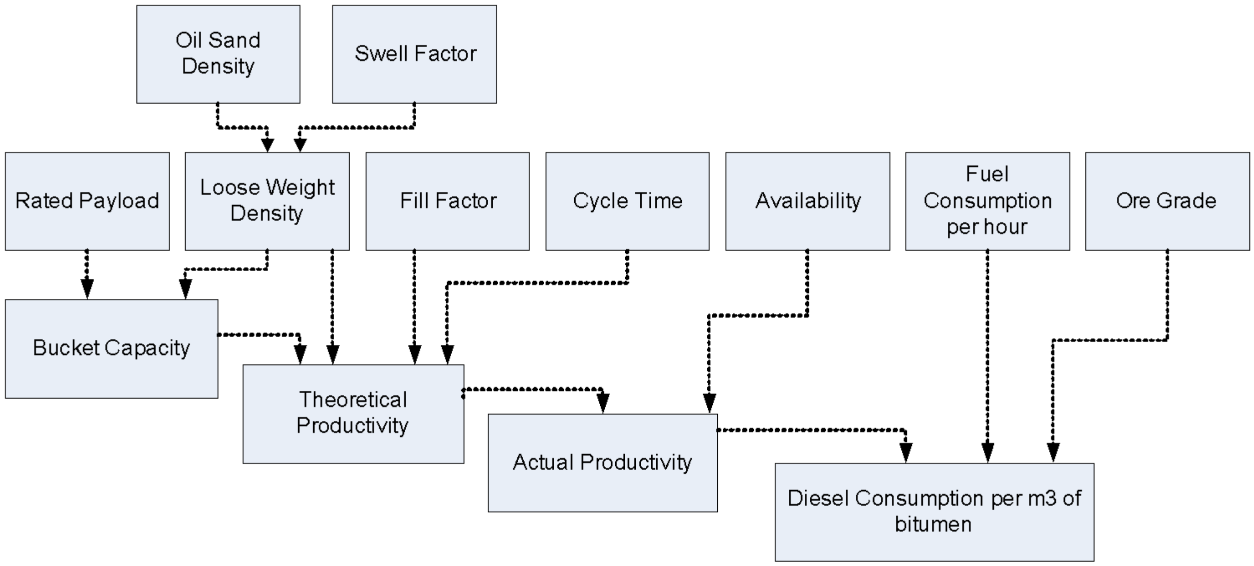

Figure 1. Methodology for calculating diesel consumption in shovels and trucks

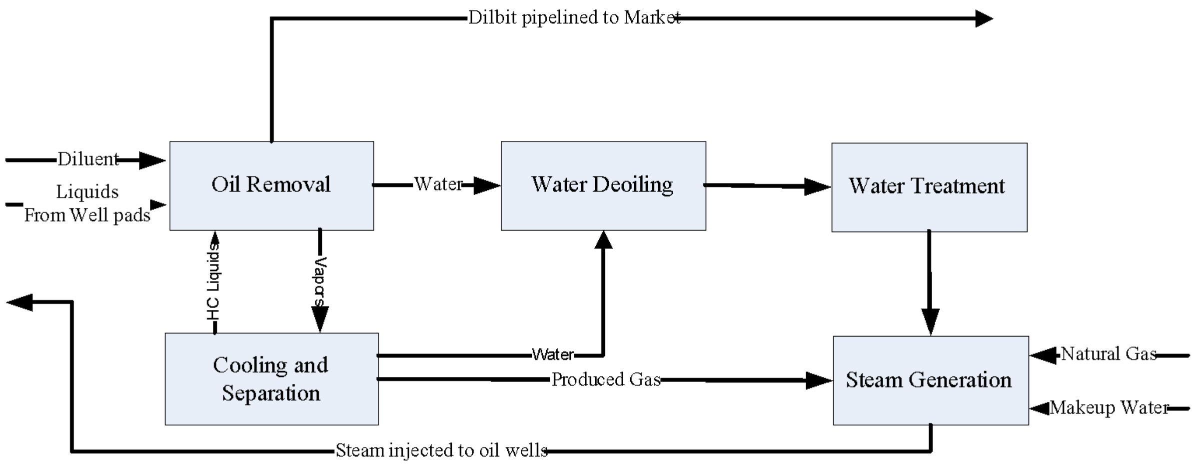

Figure 2. Subunit operations in SAGD

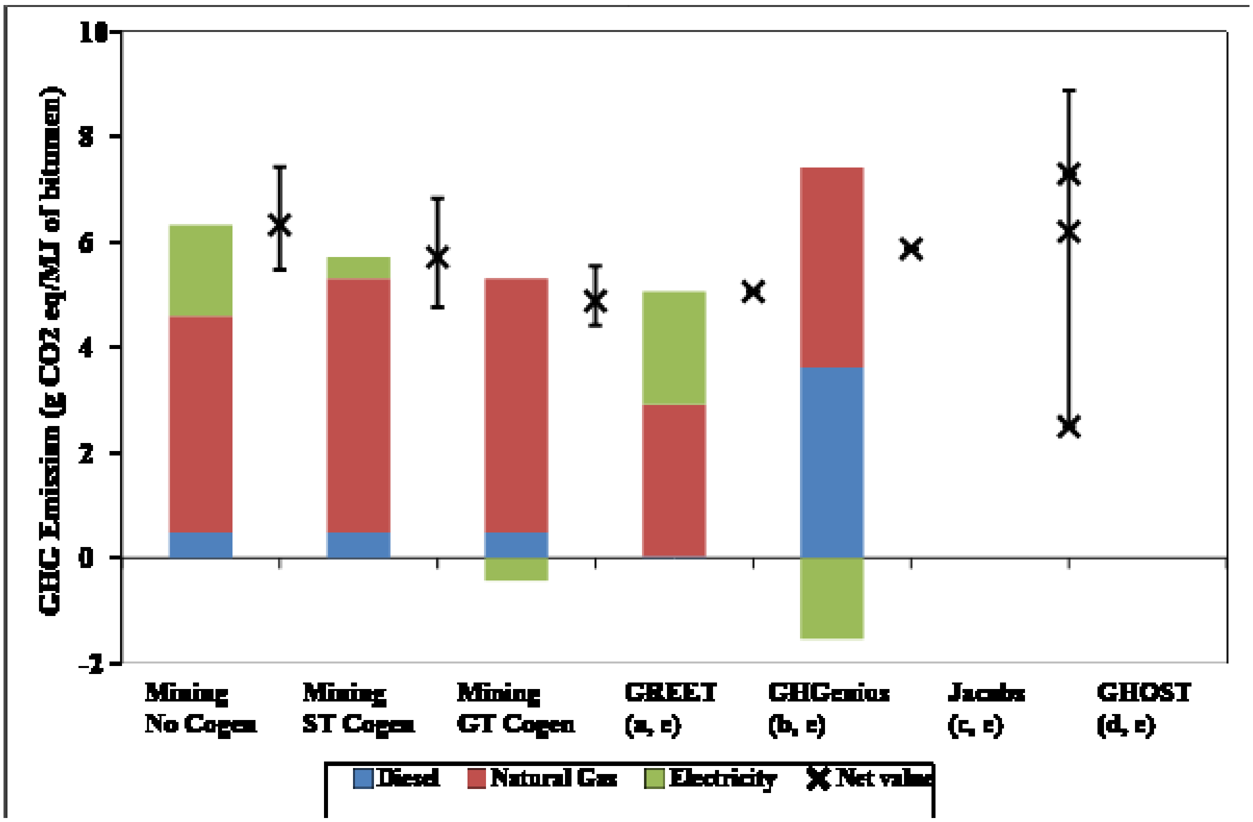

Figure 3. Estimated GHG emissions in surface mining in comparison to existing literature and models

(a) [21] Emissions are calculated based on default values of fuel consumption specified in the model; (b) [20] Emissions are calculated based on default values of fuel consumption specified in the model; (c) [10] The lower value is with cogeneration and the higher value corresponds to the “no cogeneration” case. The emissions reported are based on the assumption that energy in surface mining is about one half of the energy consumed in SAGD operation with SOR of three; (d) [24] The “no cogeneration” and “with cogeneration” ranges overlap; the range shown is a combined range; (e) Values reported in the literature have been converted using 8 API gravity and LHV of bitumen from the GHGenius, for comparison purposes.

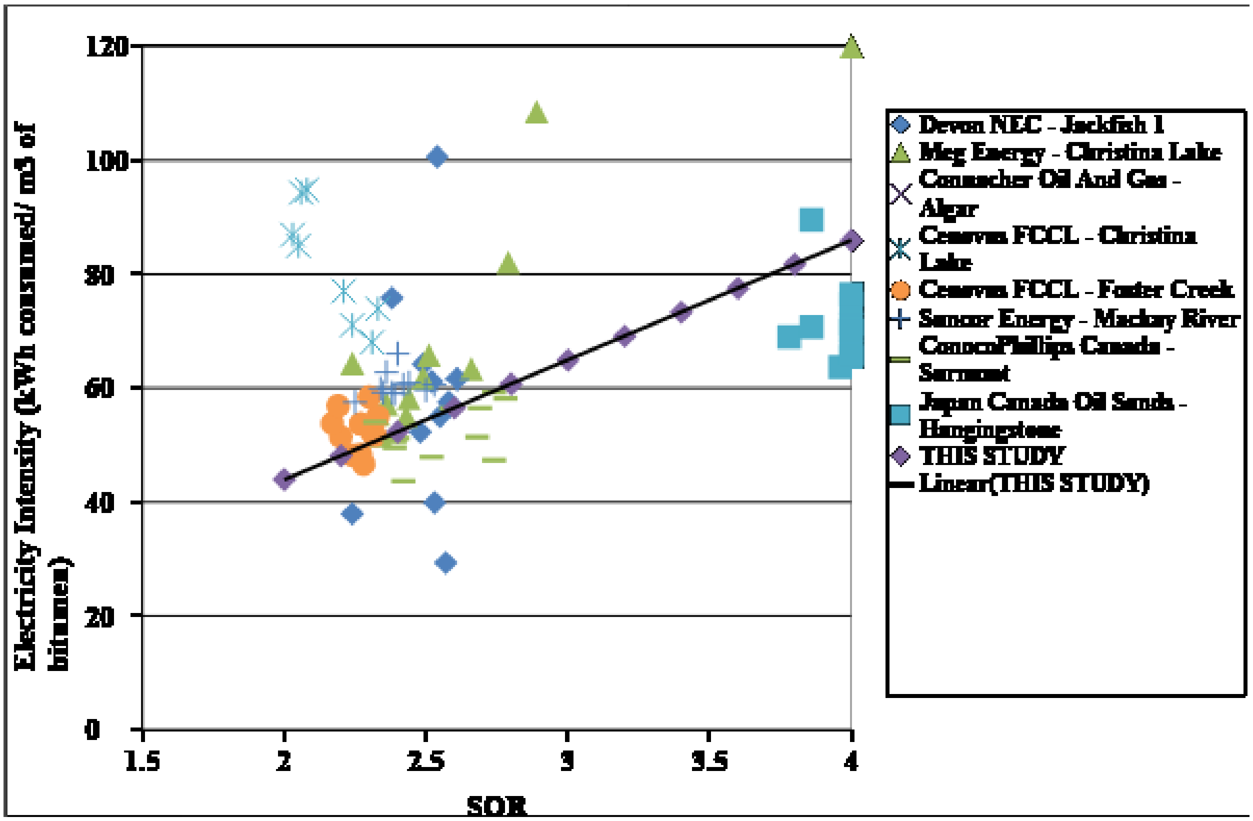

Figure 4. Correlation between electricity consumption and instantaneous SOR in SAGD

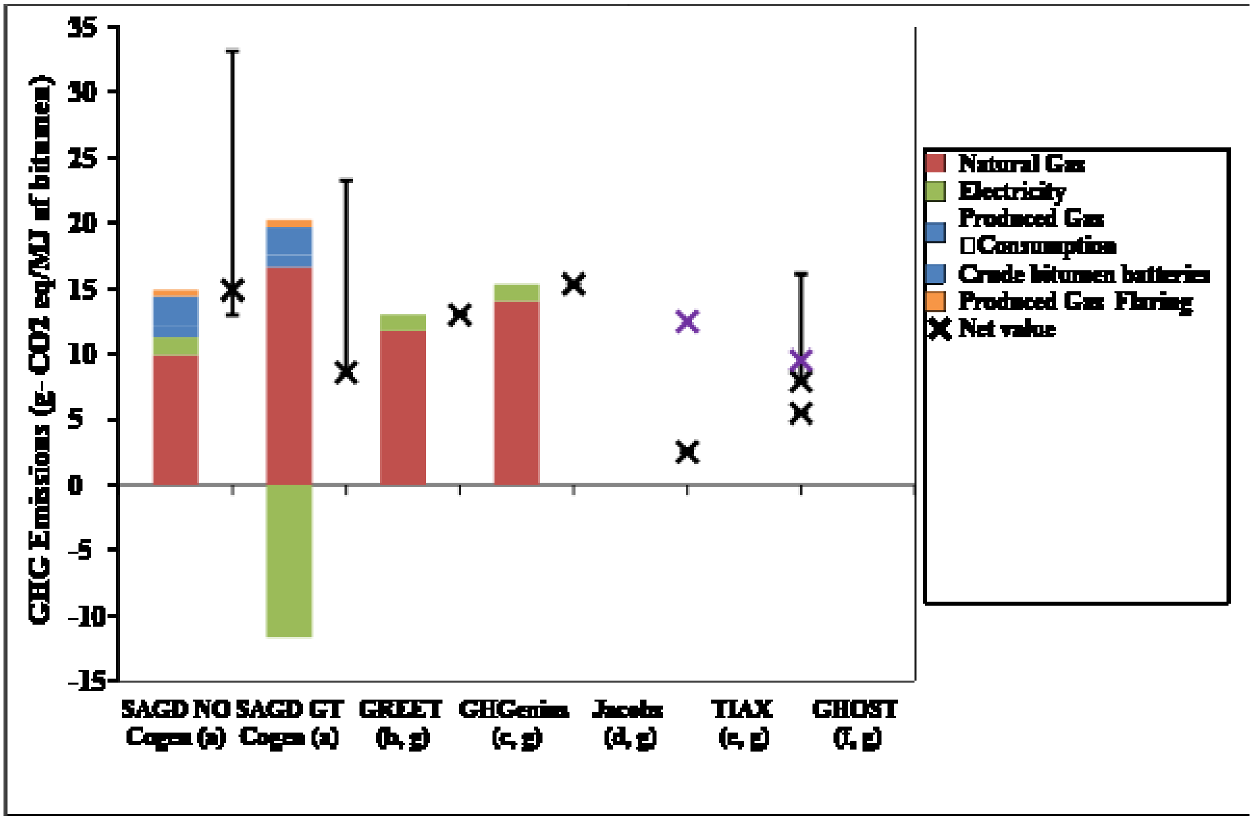

Figure 5. Estimated GHG emissions in SAGD in comparison to existing models and literature

(a) The wide range of values is due to the exclusive range of SOR considered – 2.1 to 6.54 [56], with a default value of 2.89; (b) [21]. Emissions are calculated based on default values of energy consumption specified in the model; (c) [20]. Emissions are calculated based on default values of energy consumption specified in the model; (d) [10]. The lower value is associated with cogeneration and the higher value corresponds to the "no cogeneration" case. A SOR of 3 is considered. The credits for electricity export are given based on 80% coal based grid electricity; (e) [9]. A SOR of 2.5 is considered. The higher value is for bitumen production in SAGD with electricity export; (f) The SOR considered is in the range of 2.2-3.3; (g) Values reported in the literature were converted for comparison purposes using 8 API gravity and LHV of bitumen from the GHGenius model. The GHG emissions from crude bitumen batteries are not accounted for in these studies.

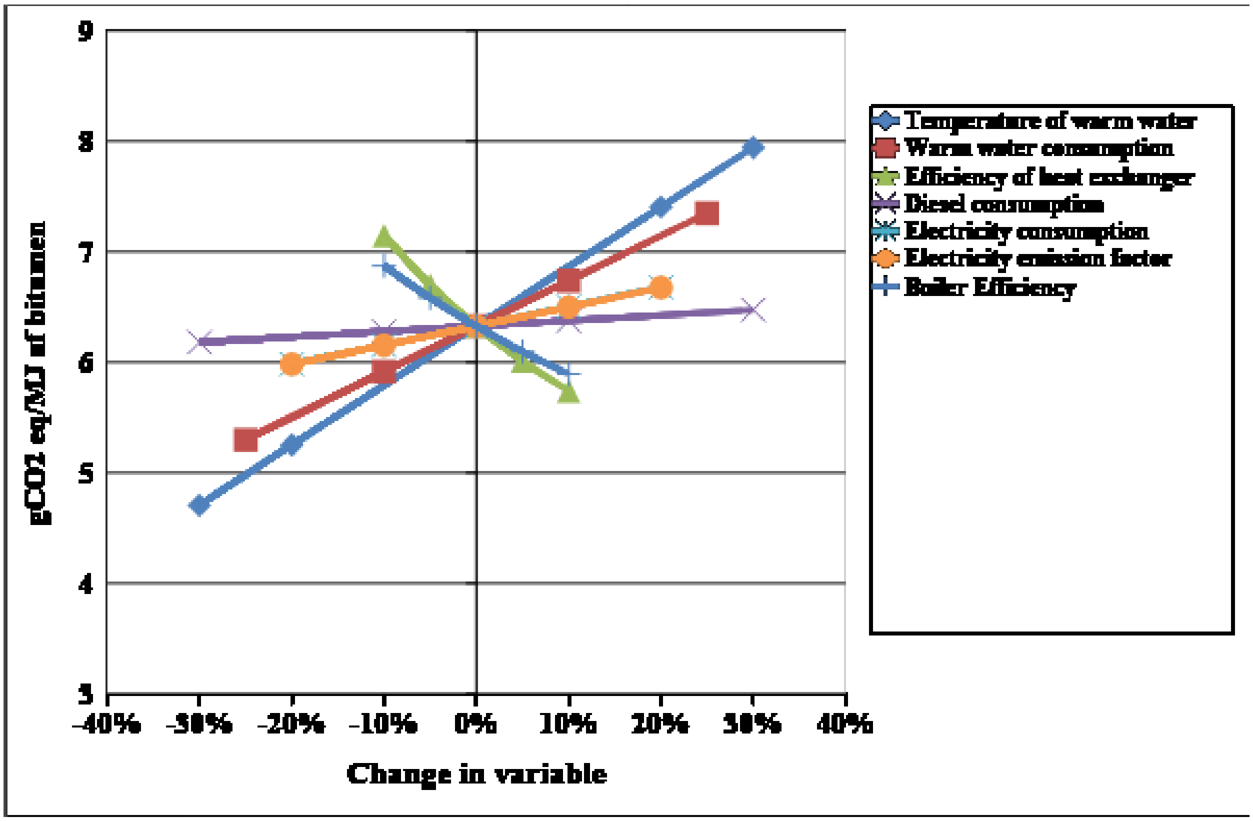

Figure 6. Sensitivity analysis of GHG emissions on key parameters in surface mining (Mining NO Cogen)

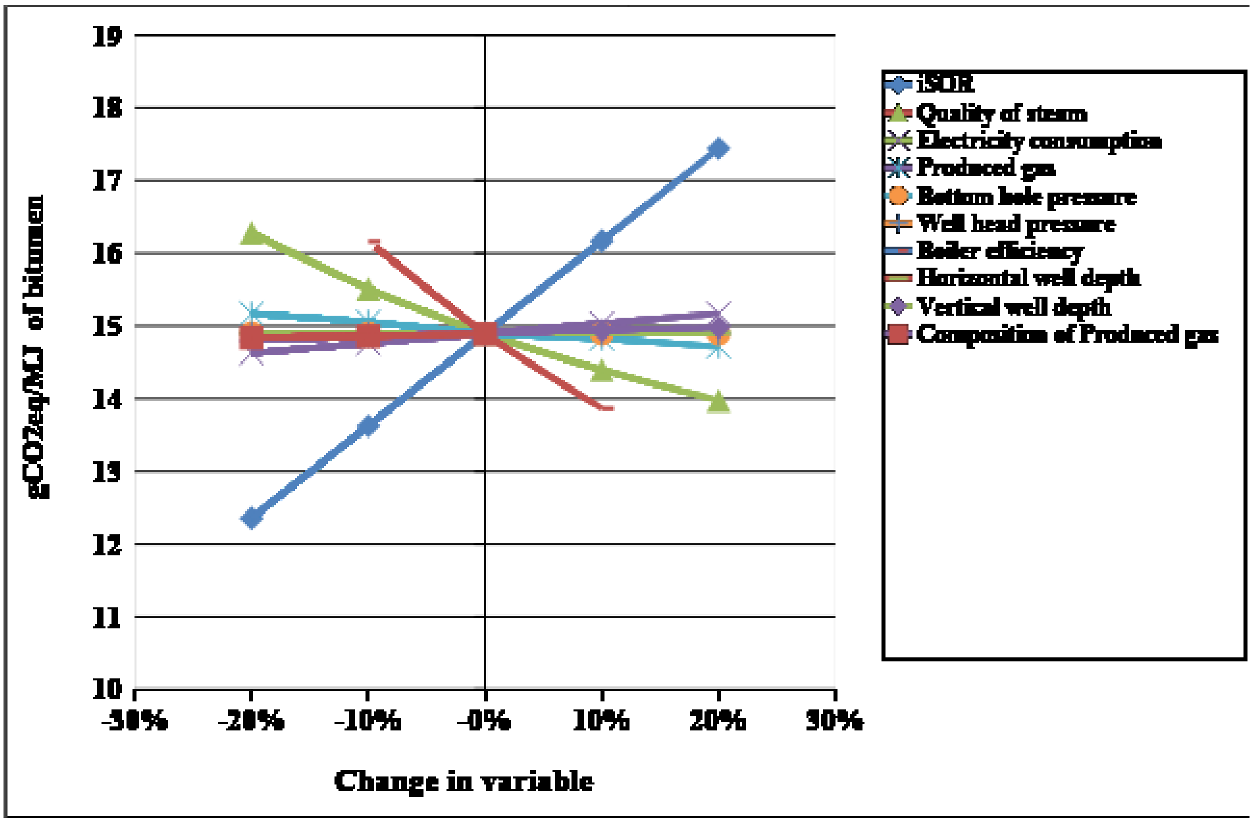

Figure 7. Sensitivity analysis of GHG emissions on key parameters in SAGD (SAGD NO Cogen)

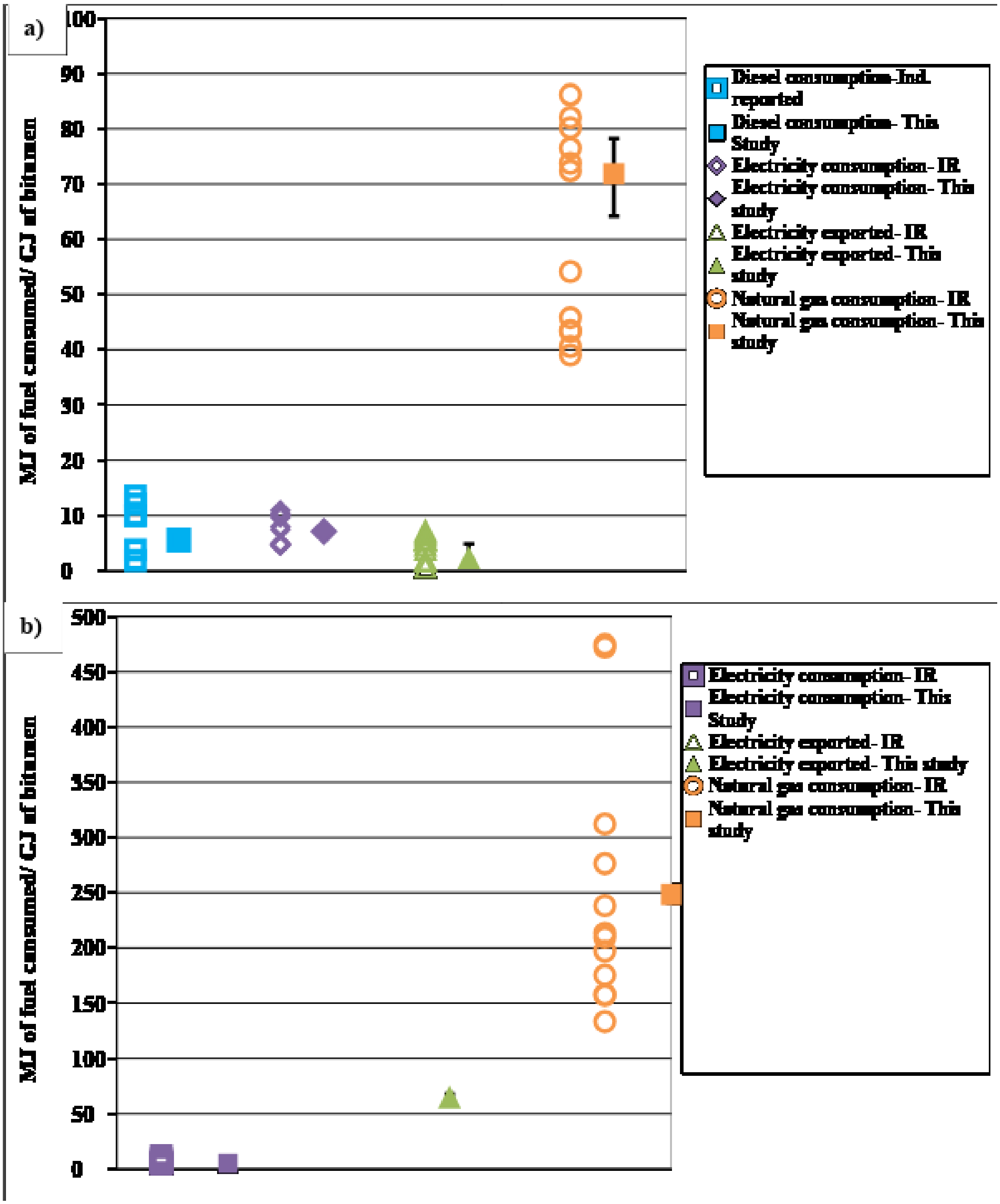

Figure 8. Comparison of energy values estimated by this research to those reported by the industry for a) surface mining, b) SAGD operation.

Note: IR refers to average annual fuel consumption values reported by the industry [45, 49].

Table 1. Input parameters to determine natural gas requirements

Parameter	**Value**	**Comments/References**
Warm water consumption (m^3/m^3 of bitumen)	8	Varies by grade (6 - 9 m^3/m^3) [26, 28, 37]
Water temperature (˚C)	50	
Efficiency of heat exchanger (%)	60	Varies depending upon the liquid temperatures and design of exchanger. A generic value is assumed and considered as a sensitivity parameter. See section 3.3
Efficiency of steam boiler (%)	85	[40]

Table 2. Technical parameters used to estimate power consumption in pumps and compressors in SAGD

Parameter	Value	Comment/Reference
Wellhead pressure (kPa)	2200	Project specific and in the range of 1100– 4500 kPa. For a gas lift, higher pressures up to 5000 kPa are used [46, 54].
Bottomhole pressure (kPa)	1200	Project specific and in the range of 390–4500 kPa [46, 55, 56].
Pump efficiency	70%	[57]
Compressor efficiency	75%	[57]
Horizontal well depth (m)	800	[46, 58]. Project specific and in the range of 550–1000m.
Vertical well depth (m)	200	[46, 59]. Project specific and in the range of 80–1000 m.

Table 3. Fuel consumption and GHG emissions in surface mining

	Fuel Consumption			Emissions		
	Unit[f]	Range	Default	Unit[f]	Range	Default
Diesel	L/m^3	5- 8	6.23	kgCO$_2$eq/m^3	16- 25.7	20
	MJ/GJ	4.4- 7.1	5.53	gCO$_2$eq/MJ	0.4- 0.6	0.5
Electricity	kWh/m^3	72 - 85	80.4	kgCO$_2$eq/m^3	63.3- 74.8[c]	70.7[c]
	kWh/GJ	1.7- 2.1	2.0	gCO$_2$eq/MJ	1.5- 1.8 [c]	1.7 [c]
Mining NO Cogen: No cogeneration						
Natural Gas	m^3/m^3	64 - 90	74.4	kgCO$_2$eq/m^3	143.9-202.4	167.2
	MJ/GJ	52.7- 74.1	61.3	gCO$_2$eq/MJ	3.5- 5.0	4.1
Electricity Co-produced	kWh/m^3	0	0	-	-	-
	kWh/GJ	0	0	-	-	-
Net electricity	kWh/m^3	72 - 85	80.4	kgCO$_2$eq/m^3	63.3- 74.8[c]	70.7
	kWh/GJ	1.8- 2.1	2.0	gCO$_2$eq/MJ	1.5- 1.8 [c]	1.7
Mining ST Cogen: Cogeneration with steam turbine						
Natural Gas	m^3/m^3	75 – 105	87.4	kgCO$_2$eq/m^3	168.6- 236.1[e]	196.5 [e]
	MJ/GJ	61.7- 86.4	72.0	gCO$_2$eq/MJ	4.1- 5.8 [e]	4.8 [e]
Electricity Co-produced	kWh/m^3	53 - 74	61.8	-	-	-
	kWh/GJ	1.3- 1.8	1.5	-	-	-
Net electricity	kWh/m^3	11 - 19	18.6[a]	kgCO$_2$eq/m^3	9.68- 16.7[c]	16.4[c]
	kWh/GJ	0.3- 0.5	0.5 [a]	gCO$_2$eq/MJ	0.2- 0.4 [c]	0.4 [c]
Mining GT Cogen: Cogeneration with gas turbine						
Natural Gas	m^3/m^3	78 - 95	87.3	kgCO$_2$eq/m^3	175.4-213.6 [e]	196.3 [e]
	MJ/GJ	64.2- 78.2	71.8	gCO$_2$eq/MJ	4.3- 5.2 [e]	4.8 [e]
Electricity Co-produced	kWh/m^3	79 - 140	107.3	-	-	-
	kWh/GJ	1.9- 3.4	2.6	-	-	-
Net electricity	kWh/m^3	7 - 55	26.9[b]	kgCO$_2$eq/m^3	-(4.5 – 35.7)[d]	- 17.5[d]
	kWh/GJ	0.2- 1.3	0.7 [b]	gCO$_2$eq/MJ	-(0.1- 0.9) [d]	- 0.4 [d]

(a) Imported from the Alberta grid; electricity production with a steam turbine in the default case is lower than the electricity demand of the project; (b) Surplus electricity is exported to the grid and displaces the coal-based grid electricity; (c) Alberta grid emissions; (d) Calculated based on an emissions factor of 650 gm/kWh [62]. Negative sign signifies the credit given for displacing GHG-intensive electricity. (e) Natural gas combustion emissions correspond to steam produced and electricity co-produced. (f) The units correspond to volume or energy unit of bitumen e.g. L/m^3 of bitumen; gCO_2eq/MJ of bitumen

Table 4. Fuel consumption and GHG emissions from SAGD

	Fuel Consumption			**Emissions**		
	Unit[g]	Range	Default	Unit[g]	Range	Default
SAGD NO Cogen: No cogeneration						
Natural Gas	m^3/m^3	150.3 - 468	180.0	$kgCO_2eq/m^3$	337.9- 1052	404.7
	MJ/GJ	123.7- 385.2	148.2	gCO_2eq/MJ	8.3- 25.8	9.9
Electricity Co-produced	kWh/m^3	0	0	-	-	-
	kWh/GJ	0	0	-	-	-
Net electricity	kWh/m^3	47.5 – 144.7	62.8	$kgCO_2eq/m^3$	41.8- 127.3[c]	55.3
	kWh/GJ	1.2- 3.5	1.5	gCO_2eq/MJ	1.0- 3.1	1.4
Produced Gas	m^3/m^3	1 – 89[a]	20.5	$kgCO_2eq/m^3$	2-200[e]	46.1
	MJ/GJ	0.3- 24.4	5.6	gCO_2eq/MJ	0.1- 4.9	1.1
SAGD GT Cogen: With cogeneration						
Natural Gas	m^3/m^3	277.5 - 562	301	$kgCO_2eq/m^3$	624- 1263.6[f]	677.4
	MJ/GJ	228.5- 462.7	247.8	gCO_2eq/MJ	15.3- 31.0	16.6
Electricity Co-produced	kWh/m^3	700 – 886	792.7	-	-	-
	kWh/GJ	17.2- 21.7	19.5	-	-	-
Net electricity	kWh/m^3	653.5-741.3[b]	730	$kgCO_2eq/m^3$	-(388- 445.3)[d]	- 474.4[d]
	kWh/GJ	16.0- 18.2	17.9	gCO_2eq/MJ	-(9.5- 10.9)	1.8
Produced Gas	m^3/m^3	1 - 89	20.5	$kgCO_2eq/m^3$	2- 200[e]	46.1
	MJ/GJ	0.3- 24.4	5.6	gCO_2eq/MJ	0.1- 4.9	1.1

(a) [44, 49, 50]: includes produced gas consumption and flaring; (b) Obtained by subtracting the lower values and higher values in the range. But other combinations may be possible; (c) Alberta grid emissions. (d) Calculated based on an emissions factor of 650 gm/kWh [62]. Negative sign signifies the credit given for displacing GHG-intensive electricity. (e) The emissions factor for produced gas is same as natural gas combustion factor [44]. The upstream emissions associated with production, recovery, and transportation are zero as this gas is produced along with the bitumen. (f) Natural gas combustion emissions correspond to steam produced and electricity co-produced. (g) The units correspond to volume or energy unit of bitumen e.g. m^3/m^3 of bitumen; gCO_2eq/MJ of bitumen