AIChE

Optimal Integration of Nuclear Energy and Water Management into the Oil Sands Operations

Alberto Betancourt-Torcat, Ali Elkamel, and Luis Ricardez-Sandoval
Dept. of Chemical Engineering, University of Waterloo, Waterloo, N2L 3G1, Canada

DOI 10.1002/aic.13736
Published online February 24, 2012 in Wiley Online Library (wileyonlinelibrary.com).

An energy optimization model is presented that includes nuclear energy and water management into the oil sands industry. The proposed model determines the most suitable configuration of energy commodities and oil producers for a given oil production scenario at minimum cost while meeting environmental constraints. The proposed model was validated using data reported in the literature for the future oil sands operations in 2030. Likewise, the proposed integrated energy optimization model was used to determine the 2030 oil sands operations using recent information reported in the literature. The results show that the energy model is a practical tool that can be used to evaluate future oil production scenarios, identify the key parameters that affect the oil sands operations, and can also be used for planning and scheduling of the energy and oil producers for this industry. © 2012 American Institute of Chemical Engineers *AIChE J*, 58: 3433–3453, 2012
Keywords: process systems engineering, oil sands operations, mathematical modeling, nuclear energy, water management

Introduction

Canadian oil sands are the third largest crude oil proven reserves in the world next to Saudi Arabia and Venezuela.[1] The oil sands consist of bitumen, a heavy and viscous crude oil found in the grounds mixed with sand, clay and water. Bitumen can be diluted with solvents, e.g., naphtha to reduce its viscosity, and, thus, enable its transportation by pipelines. Bitumen can be either sold as crude bitumen or raise to a higher grade into synthetic crude oil (SCO) via integrated steam assisted gravity drainage and upgrading (SAGD/upgrading) or mining/upgrading producers through hydrocracking or thermocracking processes. These cracking processes yield a light and sweet SCO. There are two methods to extract the bitumen from the oil sands: mining extraction and *in situ* extraction. Mining extraction is the most traditional and currently the dominant method for bitumen extraction. This method is based on traditional pit mining, which makes use of shovels to mine the oil sands and trucks to transport the bitumen to the recovering facilities where it is separated from the sand, clay and water. *In situ* extraction is based on steam assisted gravity drainage (SAGD). In this technology, steam is injected into the underground oil reservoir to heat the bitumen trapped in the sand and to promote its flow toward the surface through pipelines. The mixture of crude bitumen and condensed steam obtained by this technology on the surface is pumped to a recovering plant to separate the water from the crude bitumen.[2]

Correspondence concerning this article should be addressed to L. Ricardez-Sandoval at laricard@uwaterloo.ca.

© 2012 American Institute of Chemical Engineers

Crude oil dominates the world's energy supply, since its production is economically attractive when compared to other alternatives, e.g., wind energy, solar energy, biofuels. According to the International Energy Agency (IEA),[3] and the US Energy Information Administration (EIA),[4] the world oil demand will reach 120 million barrels daily by 2030; one quarter of this demand will come from Canada and the United States.[3,4] As the conventional crude oil production keeps declining, the unconventional crude oil sources, e.g., bitumen, are becoming more attractive and considered as strategic oil reservoirs and potential energy suppliers. According to information from the EIA,[2] Canada supplied to the US about 1.9 million barrels per day, which represents 22% of all US crude oil imports in 2010.[2] Canadian average daily crude oil production is 2.9 million barrels. Almost 50% of this production is obtained from unconventional sources such as oil sands. Moreover, 97% of the Canadian oil reserves (175.2 billion barrels of oil) are unconventional deposits.[2] The oil sands industry is expected to increase its crude oil production in the upcoming decades to ensure the US and the World's oil supply.

Since oil is expected to remain as the main source of energy in the world at least for the short term, various oil sands projects that consider new developments or expansion of the existing operations have been approved or are already under construction.[5] Also the rebound in oil prices, as a result of the economic recovery that followed the world's economic recession of 2008, has boosted the interest in the oil sands operation sector. However, there are uncertain factors related to the future growth of oil sands activities due to concerns about the availability of energy commodities, i.e., power, steam. Furthermore, environmental concerns regarding long-term greenhouse gas (GHG) emissions and water management are key aspects that both the Alberta provincial government and the Canadian federal government need to address to sustain the operability of the oil sands in the upcoming years.

The nuclear industry has significantly enhanced its performance by improving the efficiency of its processes and the security in the nuclear facilities. According to McColl et al.[6] nuclear reactors use control uranium 235 (U235) fission, which generates considerable amounts of energy to heat water and generate steam. The steam can either be used as an energy commodity, or it can be used to drive turbine-generators to produce electricity. Also, U235 reactors can generate a combination of electricity and steam. Nuclear energy is a key energy source in the Canadian economy. In 2005, nuclear power accounted for almost 11% of the total power generation capacity in this country. Moreover, according to the Canadian Nuclear Association (CNA), there were 22 nuclear reactors in Canada by December 2007[6]; however, none of them were located in western Canada. Recently, the Energy Alberta Corp. filed an application with the Canadian Nuclear Safety Commission to site its first nuclear power plant near Peace River.[7] This energy facility is expected to have a direct impact on the power supply in the Athabasca region. According to oil industry members,[6] there are small-scale nuclear energy facilities (NFE), i.e., liquid metal cooled reactors such as the Toshiba 4S, that can be deployed to the oil sands to produce SAGD steam by the year 2030.[6] Furthermore, nuclear facilities do not generate GHG emissions, which represent a major potential advantage over other energy producers given the uncertainty surrounding GHG emission reduction plans and environmental penalties for the future.

The rapid expansion in the oil sands operations also presents challenges regarding the conservation of freshwater resources, i.e., the Athabasca River. On average, 8 to 12 barrels of water are needed to produce one barrel of bitumen via mining extraction. Most of this freshwater is used in the hot water extraction process, which is employed to separate the bitumen from the sand and clay. According to Allen,[8] 70–85% of the freshwater imported by oil sands mine operators is recycled to the process. A zero discharge policy forces the oil sands operators to store the water used in their processes and tailings on site.[8] Tailings ponds are a mixture of water, clay, sand, and residual bitumen. These ponds allow the water to be recycled in the mining operations, but they also generate a large landscaping impact.[9] However, the recycle of water from tailings ponds in the oil sands operations has significantly reduced the demand for freshwater in bitumen recovery.

Mathematical programming models for the optimization of energy markets have been reported in the literature. An electricity market model that presents the price of electricity supply as an exogenous variable has been developed, i.e., the marginal price of the system is an input parameter for the optimization problem.[10] Accordingly, the market revenue becomes a linear function of the electricity company's production, which represents the main decision variable in that energy market optimization model. Common linear programming (LP) and mixed-integer linear programming (MILP) techniques were used to solve that model.[10] However, this type of optimization models can only be applied to represent markets under quasi-perfect competition conditions because it does not account for the company's decision on the market marginal price. Gross and Finlay[11] presented a deterministic model for optimal bidding strategies in competitive electricity markets in which the optimization problem can be decomposed into a set of subproblems corresponding to the Lagrangian relaxation approach. In that deterministic model, the difference between the marginal cost of each electricity generator of a company and the market price determines the production of each generator. A limitation in the previous modeling approaches is that the fluctuations or uncertainty in the electricity prices was not considered in the analysis. Accordingly, Rajamaran et al.[12] developed a self-commitment optimization model for an electricity generation company considering uncertainty in the price values. The model in that study was solved using backward dynamic programming under different scenarios to show the capabilities of that modeling approach.[12] The energy markets models described above have been developed to study the supply and demand in the electricity sector for commercialization. Consequently, those studies have been developed for particular applications, e.g., local and regional electricity markets. In contrast to those studies, this optimization model considers the large-scale operation of the unconventional Canadian oil industry, which includes the supply and demands of the energy commodities, e.g., power supply and demand.

Due to the importance of oil sands activities and their impact on the world's oil production, mathematical models that describe future potential scenarios have been developed.[13,14] These models have been used to determine the most suitable configuration of commodity producers that minimize the energy generation costs of the oil sands. The energy costs in these models were assumed to be dependent on the energy commodity required by the oil sands producers. Also, the commodity demands were assumed to be fixed since the individual production capacities of each type of crude bitumen and SCO producer were considered as inputs to the model. Although nonanalytical studies that discuss the use of nuclear energy in the oil sands operations are available,[6,15,16] the previous oil sands models did not include nuclear energy as an alternative resource to produce energy. Furthermore, water management and its impact on the oil sands operations has not been explicitly considered in the previous modeling studies.

This article introduces a new integrated energy model for the Canadian oil sands operation. The key feature of this model is that the oil sands producers, the energy commodity producers, and their corresponding capacities are treated as decision (optimization) variables. The proposed model also includes environmental constraints in its formulation, i.e., CO_2 emission reduction. A key aspect is the inclusion of nuclear energy facilities as additional resources to generate energy to cover the oil producer's energy demands. Likewise, water management is explicitly considered to account for the use and recycling of water in the oil sands mining operations. To the authors' knowledge, the integrated model proposed in this work is the first that accounts for nuclear energy, water management and simultaneously solves for the most suitable oil sands producers and energy commodity producers' configuration that minimizes an energy cost function for the oil sands operations. The oil sands producers considered in the model are the commercial crude bitumen

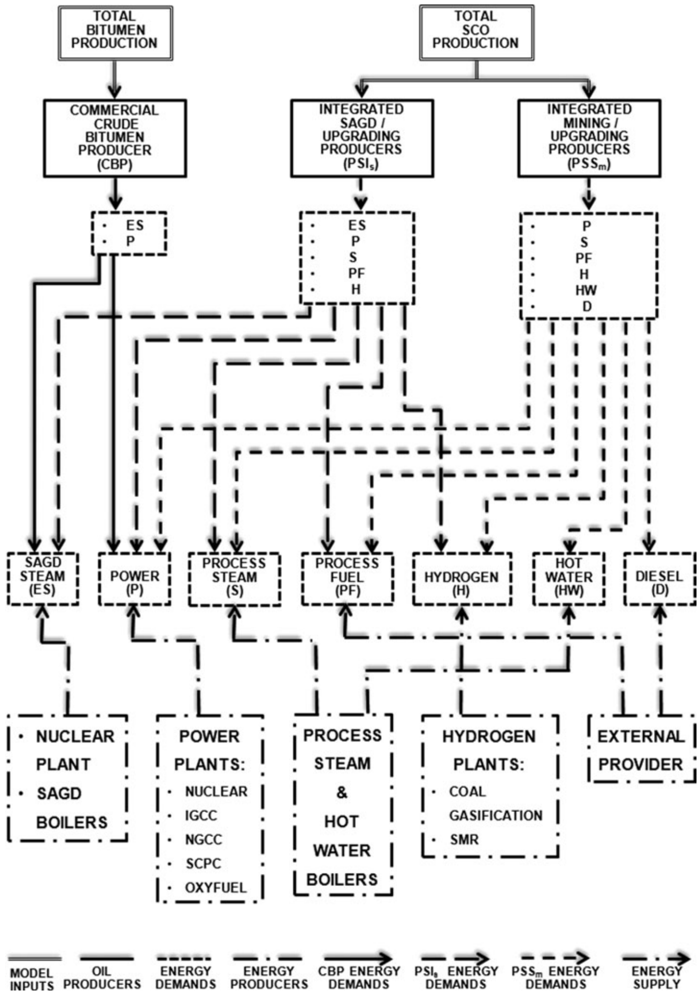

Figure 1. Energy model layout.

and SCO producers, i.e., SAGD bitumen extraction for commercial bitumen production, and integrated mining/upgrading and SAGD/upgrading for SCO production, whereas the energy commodity producers are the power plants, hydrogen plants, boilers and nuclear facilities that are used to cover the energy requirements of the oil sands operations. The proposed integrated energy model was validated using data reported in a previous study by Ordorica-Garcia et al.[17] Also, a case study that shows the potential benefits of using the proposed integrated model with respect to the previous models is discussed. Furthermore, a future production scenario with and without environmental constraints, i.e., CO_2 emissions was simulated with the proposed integrated model to analyze the effects of environmental constraints on the oil sands operations.

This article is organized as follows: The Optimization Model section presents a detailed description of the energy model developed in this work. The Case Study 2030 section presents a case study that was solved under four different scenarios. The scenarios considered were used to validate this model, to show the potential benefits of using an integrated energy model, to determine the future oil sands operations and to analyze the effects of environmental constraints on the future activities of this industry. Conclusions are are given in the last section.

Optimization Model

This section presents the integrated energy optimization model. The proposed model includes integrated SAGD/upgrading and mining/upgrading as SCO producers and *in situ* (SAGD) for commercial crude bitumen production. The energy requirements are supplied by energy commodity producers. That is, process steam and hot water are supplied by boilers, SAGD extraction steam is provided by boilers and small-scale nuclear facilities, electricity is supplied by conventional fossil fuel and nuclear plants and hydrogen plants provided the hydrogen for the oil sands operation. The model also considers the use of process fuel (natural gas) for hydrocracking and thermocracking in upgrading, and diesel to fuel trucks and shovels for the oil sand mining operations. Furthermore, the model considers CO_2 capture and sequestration (underground CO_2 sinking) as an environmental constraint. Figure 1 shows a schematic representation of the integrated energy model proposed to estimate the energy costs for the oil sands operation. The energy optimization model shown in Figure 1 can be conceptualized as follows:

$\min_{\eta}$	Cost Function	(Cost Function and Optimization Variables section)
s.t.	Energy Commodity Producers	(Energy Commodity Producers section)
	SAGD Commercial Crude Bitmun Production	(Commercial Crude Bitumen Production section)
	Integrated SDGD/Upgrading SCO production schemes	(Integrated SAGD/Upgrading SCO producers section)
	Integrated SAGD/Upgrading SCO production schemes	(Integrated Mining/Upgrading - SCO producers section)
	Production Capacities	(Commercial Crude Bitumen Production, Integrated SAGD and Mining/Upgrading SCO producers sections)
	Environmental Constraint	(Environmental Restrictions section)
	Total Energy Commodity Requirements	(Total Energy Commodity Requirements section)
	Energy Commodity Supply Constraints	(Energy Commodity Supply Constraints section)

where η is the set of decision variables considered in the model. Each of the modeling aspects included in this formulation are discussed later.

Energy commodity producers

In this study, the commodity producers are included in the model to supply the energy requirements to maintain the oil sands operations. The energy commodities considered are electricity, hydrogen, process steam, hot water, SAGD extraction steam, process fuel (natural gas) and diesel.

Power Plants. A novel feature included in this model is the use of nuclear energy to cover the oil sands electricity requirements. Nuclear energy is a zero carbon footprint technology, i.e., it does not produce GHG emissions. This characteristic makes nuclear energy an attractive technology to reduce carbon dioxide emissions. Environmental and political organizations in Canada have requested to pass regulations that will set a carbon dioxide cap for the oil sands operators.[18] Also, a carbon emission trading system and carbon tax are being considered to control and penalize those producers that do not meet their GHG emission quota.[19–21] Hence, nuclear energy emerges as an attractive technology to generate energy for the oil sands industry. Also, nuclear technology may play an important role in the upcoming future of Alberta and the oil sands since an application has been filed to build the first nuclear power plant in the Athabasca region.[7] Thus, the addition of nuclear power in this oil sands operations' model represents a feasible operating strategy that may be present in future oil sand production scenarios.

Electricity is employed in different stages of the oil producers, i.e., SAGD extraction, hydrotransport, diluted bitumen recovery and upgrading (see Commercial Crude Bitumen Production, Integrated SAGD and Mining/Upgrading SCO producers sections for energy demand details). Besides nuclear plant models obtained from Thomas,[22] the other types of power plants considered in the optimization model are: integrated gasification combined cycle (IGCC), based on a study by Ordorica-Garcia et al.[23] natural gas combined cycle (NGCC) modeled from information reported by Rubin et al.[24] supercritical pulverized coal (SCPC),[24] and oxyfuel modeled with information obtained from Davison.[25] These types of power plants are considered with and without CO_2 capture technologies except for the oxyfuel plants that only included the CO_2 capture type. The cost of power production (P_c) is formulated as follows

$$P_C = \sum_{p=1}^{P} (G_p(N_p(NC_p + CNA\ PNA\ RAF) + (1 - N_p)H_pF_p) + P_p(C_p + OM_p))$$

$$N_p = \begin{cases} 1 & \text{if power plant } p \text{ is nuclear} \\ 0 & \text{otherwise} \end{cases} \quad (1)$$

where the subindex p represents the type of power plant, G_p (kW) is the power generated in power plants type p, P_p is an integer variable that defines the number of power plants type p considered in the analysis, NC_p (\$/kW/yr) is the cost of nuclear power, CNA (\$) is the total cost of a nuclear accident, PNA ((reactor·yr)$^{-1}$) is the probability of occurrence of a nuclear accident, RAF is a factor associated with the individual-risk perception, H_p (GJ/kW/yr) is the amount of fuel required per unit of power produced, F_p (\$/GJ) is the cost of the fuel used by the plants, C_p (\$/yr) is the amortized capital cost of the plant in 1 year, and OM_p (\$/yr) is the operating and maintenance cost.

As shown in Eq. 1, this energy optimization model also includes penalties associated with the production of electricity through nuclear power technologies. These economic penalties are the costs related to nuclear fuel waste management (spent nuclear fuel) and disposal, which is included in the operating and maintenance (OM) cost of the nuclear power plants (OM_p) in Eq. 1. The nuclear waste management costs, which are charged to the users, are included in the final generation costs per unit of power produced (\$/kWh) by nuclear power plant. In most countries, the nuclear waste management costs are collected in a national fund that is used to pay for the costs of constructing and operating permanent spent fuel repositories. Models that incorporate environmental, social and political aspects associated with the use of nuclear technologies for energy generation are available in the literature. The model proposed by Eeckhoudt et al.[26] incorporates individual-risk perception into the expected utility to evaluate the external costs that nuclear fuel imposed on the environment and society. Similarly, Margulies[27] proposed a risk-optimization modeling approach to determine the location of nuclear power plants including the induced environmental risks and associated factors. Moreover, Cowing et al.[28] considers the short-term tradeoffs between safety and productivity inherent to the operation of nuclear power facilities. A universally accepted method for the direct final disposal of spent nuclear fuels is not currently available. In this analysis, the approach proposed by Eeckhoudt et al.[26] has been considered to account for the nuclear fuel cycle external cost, e.g., environmental and social impacts due to the use of nuclear energy for power generation, which are represented by the factors CNA, PNA and RAF in Eq. 1. These factors represent inputs into this energy model.

Hydrogen Plants. Hydrogen is only used for bitumen upgrading by the SCO producers (see sections Integrated SAGD and Mining/Upgrading SCO producers). The hydrogen plants included in the model are steam methane reforming (SMR)[29–30] and coal gasification[31–32] with and without CO_2 capture technologies, respectively. The annual cost of hydrogen production (H_c) is estimated as follows

$$H_C = \sum_{h=1}^{H} (FD_h\, HF_h\, F_h + N_h\, (C_h + OM_h)) \quad (2)$$

where the subindex h represents the type of hydrogen plant, FD_h (Nm^{3}of natural gas/yr or Kg of coal/yr) is the fuel demand per plant type h, HF_h (GJ/Nm^3 or GJ/Kg) is the heating value of the fuel, F_h (\$/GJ) is the cost of the fuel used by the plants, N_h is the integer variable that represents the number of plants, C_h and OM_h (\$/yr) are the capital and operating costs of the plants. The electricity demand of hydrogen plants type SMR (DP_H) is calculated as follows

$$DP_H = \sum_{h=1}^{H} (HS_h H_h ES_h)$$
$$HS_h = \begin{cases} 1 & \text{if hydrogen plant } h \text{ is of type SMR} \\ 0 & \text{otherwise} \end{cases} \tag{3}$$

where H_h (tonne H_2/yr) is the amount of hydrogen produced in the plants, and ES_h (Kw·yr/tonne H_2) the electricity consumption in the plants. On the other hand, the coal gasification plants coproduce enough power to cover their own energy demands and may add power to the electricity grid supply of the oil sands producers.

Process Steam and Hot Water Boilers. Process steam is used in the following SCO production stages: conditioning, diluted bitumen recovery and upgrading. Similarly, hot water is used in conditioning, hydrotransport and diluted bitumen recovery (see sections Integrated SAGD and Mining/Upgrading SCO producers). Boilers (B) are used to simultaneously produce process steam (6,300 kPa and 500°C), and hot water (35–50°C). According to Harrel,[33] this model assumes that the boilers B are fueled with natural gas with an installed capacity of 2,978,400 tonnes of steam per year. The cost associated with process steam (S_c) is estimated as follows

$$S_C = CSB\ NB\ FD_B H_{NG} F_{NG} + S\ WC \tag{4}$$

where CSB (%) is the percentage of the boiler's capacity used for process steam generation (82%[33]), NB is an integer variable that represents the number of boilers producing steam, FD_B (Nm^3/yr) is the amount of natural gas demanded by the boilers, B, H_{NG} is the heating value of natural gas (typical value for western Canadian gas, $H_{NG} = 0{,}038$ GJ/Nm^3),[33] F_{NG} (\$/GJ) is the natural gas cost, S (tonne/yr) is the amount of steam produced by the boilers, and WC (\$/tonne) is the cost of the boilers' feed water. This model assumes that 18% of the boiler's capacity is used for hot water production. The cost related to produce hot water (HW_c) is estimated as follows

$$HW_C = NB\ FD_B\ (1 - CSB)\ H_{NG}\ F_{NG} + HW\ WC \tag{5}$$

where HW (tonne/yr) is the amount of hot water produced by the boilers.

SAGD Steam Boilers. Boilers that produce SAGD steam (BE) are used for *in situ* bitumen extraction (SAGD extraction) in SCO and commercial crude bitumen production (see sections Commercial Crude Bitumen Production and Integrated SAGD/Upgrading SCO producers). This type of boiler uses natural gas as fuel and produces steam with 80% quality at 8,000 kPa. The installed capacity considered for the boilers is 2,978,400 tonne per year.[33] The production cost of SAGD steam from boilers (ES_{BC}) is calculated as follows

$$ES_{BC} = NBE\ FD_{BE}\ H_{NG}\ F_{NG} + ES_{BE}\ WC \tag{6}$$

where NBE is the integer variable that defines the number of boilers producing SAGD extraction steam, FD_{BE} is the demand of natural gas in the boilers type BE, and ES_{BE} is the total amount of SAGD steam produced in the boilers type BE. As shown in Eqs. 4–6, the annual capital and operating and maintenance (OM) costs associated with the production of process steam, hot water and SAGD steam have not been considered in this analysis. Previous studies[14,17] have shown that the annual capital cost (especially when amortized over 20+years), and the OM costs for these energy commodities are not significant when compared to the fuel and the water consumption costs. Therefore, this energy model neglects the annual capital and OM costs for these units (boilers), since they do not significantly contribute to the costs associated with the production of process steam, hot water and SAGD steam.

Nuclear SAGD Steam Plants

This energy optimization model also includes SAGD extraction steam generated by small-scale nuclear energy facilities (*NEF*) such as the liquid metal cooled reactor Toshiba 4S.[6] This reactor model was designed to operate continuously for 30 years and does not need to be refueled during its operational lifetime. The model considers *NEF* of 108 GJ per h, which produces steam at 500°C and 10 MPa. According to a study by McColl et al.[6] the quality of the steam generated from these reactors is sufficient to be used on *in situ* extraction activities in the Canadian oil sands.

The cost of steam produced in nuclear facilities (ES_{NC}) is estimated as follows

$$ES_{NC} = N_N(C_N + OM_N) + ES_N\ F_N \tag{7}$$

where N_N is the integer variable that specifies the number of Toshiba's 4S nuclear facilities producing SAGD steam, C_N (\$/yr) is the amortized annual capital cost of the facility, OM_N (\$/yr) is the annual operating and maintenance cost, ES_N (tonne/yr) is the amount of SAGD extraction steam produced, and F_N (\$/tonne) is the steam production cost.

Commercial crude bitumen production

Oil sands within 75 m from the surface can be recovered through mining; otherwise, it needs to be extracted using *in situ* methods.[1] About 80% (135 billion barrels) of the bitumen reserves in the Athabasca region require *in situ* methods to be recovered. This energy model assumes that *in situ* extraction method, i.e., SAGD, is the only method used for *commercial* bitumen production. That is, the bitumen obtained by *in situ* extraction can be sold directly to the oil market. On the other hand, the energy model considers that both mining extraction and *in situ* extraction, i.e., SAGD; produce crude bitumen that can be further upgraded to synthetic crude oil (SCO). This is because the crude bitumen extracted via mining contains relative high levels of solids and water, i.e., the mined oil sand is triturated through mechanical methods to reduce the size of the rocks where the bitumen is trapped in the reservoir. Thus, mined bitumen has been traditionally upgraded to SCO on site instead of being sold directly as a commercial product because the levels of water and solids make it unsuitable for shipping to conventional refineries.[34–35] Consequently, *in situ* extraction (SAGD) is the only method considered in this model for commercial bitumen production, since it is currently replacing mining as the main extraction method. Also, it is expected that by year 2020 *in situ* extraction (SAGD) will become the leading extraction method in the oil sands.[1] The energy requirements involved in crude bitumen production are SAGD steam and electricity. The demand for steam (DES_{CB}) is calculated as follows

Table 1. Synthetic Crude Oil and Commercial Bitumen Producers

Producer	Stages[a]
	Integrated Mining/Upgrading
PSS_1	Mining → Hydro → DBE → LCF → FC → H
PSS_2	Mining → Hydro → DBE → LCF → FC → H ↘Cond↗
PSS_3	Mining → Hydro → DBE → LCF → H
PSS_4	Mining → Hydro → DBE → DC → H
	Integrated SAGD/Upgrading
PSI_1	SAGD → LCF → FC → H
PSI_2	SAGD → LCF → H
PSI_3	SAGD → DC → H
	Diluted Bitumen
CBP	SAGD

[a]Cond = Conditioning, DBE = Diluted Bitumen Extraction, DC = Delayed Coking, FC = Fluid Coking, H = Hydrotreatment, Hydro=Hydrotransport, LCF = LC-Fining, SAGD = Steam Assisted Gravity Drainage.
Note: PSS_2 assumed that 25% of the oil sand processed with this producer is treated using conditioning whereas the remaining 75% goes directly to hydrotransport.

$$DES_{CB} = SOR\ CB \tag{8}$$

where *SOR* is the steam to oil ratio parameter. A typical value assumed for *SOR* is 2.4 tonne of steam/tonne of bitumen.[36] The term *CB* (tonne/yr) is the crude bitumen production. The electricity demand (DP_{CB}) is calculated as follows

$$DP_{CB} = \frac{ER_{CB}\ CB\ (1 + ER_{GP})}{\rho_B\ UC} \tag{9}$$

where ER_{CB} (3.54e–4 kW·yr/bbl bitumen[13]) is a parameter that defines the electricity consumed during the production process of *commercial* crude bitumen, ER_{GP} (10%)[13] is a parameter that represents the electricity required to store and handle the commercial crude bitumen for shipping to the oil refineries for further processing, ρ_B (1.014 tonne/m^3)[13] is the bitumen density, and *UC* (0.158987 m^3/bbl) is a conversion factor.

Integrated SAGD/upgrading SCO producers

The Integrated SAGD/Upgrading producers are becoming attractive SCO producer methods since most of the bitumen reservoirs can only be recovered via *in situ* extraction methods, e.g., SAGD. This type of SCO producer can be divided into two stages: *in situ* bitumen extraction (via SAGD) and an upgrading stage where the diluted crude bitumen is upgraded to SCO. This energy model includes three upgrading routes that are the leading technologies currently employed in the oil sands[37] and are as follows:

Route 1 (R_1): LC-Fining (*LCF*) + Fluid Coking (*FC*) + Hydrotreatment (*H*)

Route 2 (R_2): LC-Fining (*LCF*) + Hydrotreatment (*H*)

Route 3 (R_3): Delayed Coking (*DC*) + Hydrotreatment (*H*)

The term *LC-Fining* is the commercial name used for the hydrocracking process developed by the joint venture of *Lummus*, an international engineering company, and *Chevron*, which resulted in Chevron Lummus Global (CLG). As shown in Table 1, the upgrading routes are combined with a bitumen extraction method (*in situ* or surface) to form an SCO producer. The total production of SCO via Integrated SAGD/Upgrading (TO_{SO}) is calculated as follows

$$TO_{SO} = \sum_{s=1}^{j} SCOI_s \tag{10}$$

where the subindex s represents the integrated SAGD/upgrading producers, and $SCOI_s$ (bbl SCO/d) is the corresponding SCO production capacity of the s^{th} producer. Equation 10 allows the model to select the appropriate SCO producer and its corresponding production capacity. This is a new feature in energy optimization models for the oil sands operation since previous modeling studies[14,17] assumed that the SCO production capacity and the SCO producer were known *a priori*. This limits the solutions presented by the previous energy models since a more economically attractive operation for this industry may be obtained when the SCO producers, and their corresponding production capacities, are set as optimization variables as it is considered in this energy optimization model.

In Situ Bitumen Extraction (SAGD). The energy requirements involved in the SAGD bitumen extraction stage for the integrated SAGD/upgrading producers are the following

$$DES_{SO} = SOR \sum_{s=1}^{j} BI_s \tag{11}$$

$$DP_{SO} = \frac{ER_B}{\rho_B\ UC} \sum_{s=1}^{j} BI_s \tag{12}$$

where DES_{SO} and DP_{SO} are the steam and power demands for SAGD extraction, respectively. The term BI_s (tonne/yr) represents the amount of bitumen considered for SCO production.

Upgrading. The energy demands for the upgrading stage are a function of the upgrading route followed by each SCO producer. Figure 2 illustrates the different stages considered in this model for upgrading. As shown in the figure, the first step in upgrading consists of recovering the naphtha used to dilute the crude bitumen for its transportation via pipeline in the diluent recovery unit (DRU), i.e., the crude bitumen viscosity is too high to be transported via pipeline; thus, diluent addition is used to facilitate the transport of this heavy oil. The products from this first step are naphtha, which is recycled back to the system, light gas oil (LGO), which is sent to hydrotreatment to remove the nitrogen and sulfur impurities, and atmospheric topped bitumen (ATB), which can be transported to the vacuum distillation unit (VDU), or sent to both the VDU and the LC-finers (R_1), or transported to delayed cokers (R_3) (see Figure 2). The cokers are units where the bitumen is cracked into lighter hydrocarbons using thermal energy (thermocracking). In the second upgrading stage, the bottom products from the VDU known as vacuum topped bitumen (VTB) are mixed with any residual ATB coming from the DRU and then sent to LC-finers (R_1) or to delayed cokers (R_3) (see Figure 2). Likewise, the LGO and heavy gas oil (HGO) are sent to hydrotreatment. In the LC-finers, the heavy hydrocarbons are cracked into lighter hydrocarbons using hydrogen. This model considers two types of LC-finers: low[38–40] (R_1) and high[41] (R_2) conversion. In the third upgrading stage, the products from the LC-finers, i.e., naphtha, LGO and HGO are sent to hydrotreatment. The bottom products of the LC-finers are sent to the fluid coker (R_1). The fluid cokers treat the bottoms proceeding from upstream units to yield additional light hydrocarbons, i.e., LGO, HGO and naphtha (R_1).[39] In the last upgrading stage, the upstream products (naphtha, LGO and HGO) are treated with hydrogen (hydrotreatment[38]) to remove the sulfur and nitrogen impurities to yield a light and sweet product, i.e., SCO (see Figure 2).

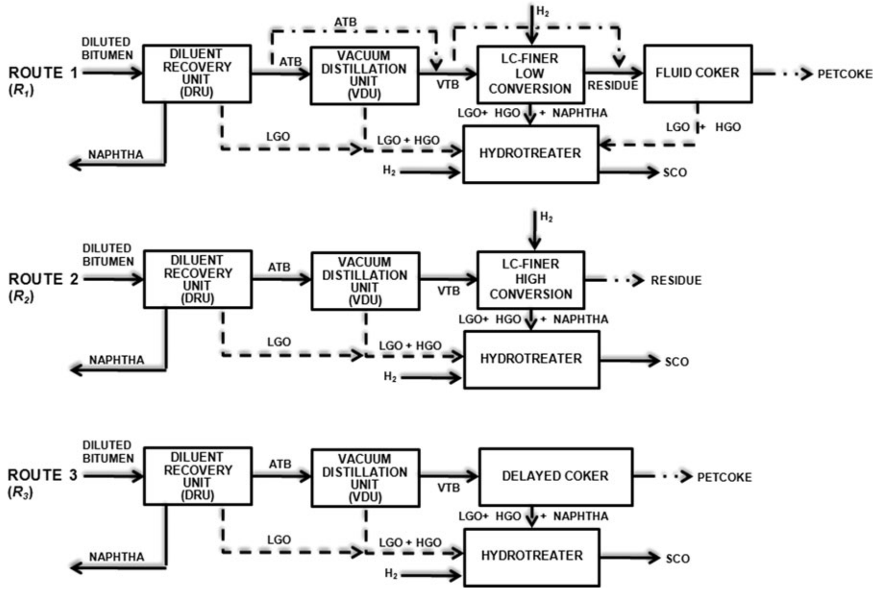

Figure 2. Upgrading routes.[13]

The specific energy demands per producer are presented next. Accordingly, the hydrogen requirement for hydrocracking in producers following route R_1 is formulated as follows

$$DHI_{C1} = \frac{HRLF}{\rho_{H_2}} \sum_{s=1}^{j} (LF_s(VTB_s + ATB_s))$$
$$LF_s = \begin{cases} 1 & \text{if } s \text{ follows upgrading Route } R_1 \text{in SAGD/Upgrading} \\ 0 & \text{otherwise} \end{cases} \tag{13}$$

where DHI_{C1} is the hydrogen demand in R_1, VTB_s and ATB_s (tonne/yr) are the VTB and ATB feed streams to the LC-finer, respectively; $HRLF$ (6,046 ft^3 H_2/tonne feed[39]) is a parameter that defines the hydrogen requirement in producers following route R_1, and ρ_{H2} (423,300 ft^3/tonne[42]) is the hydrogen density. The variable ATB_s is calculated as follows

$$ATB_s = \sum_{s=1}^{j} (LF_s(BI_s\,(1 + DRB\,(1 - DDRU))\,(1 - LDRU))) \tag{14}$$

where DRB (0.2278 tonne diluent/tonne bitumen[13]) represents the diluents requirement for SAGD bitumen in producers following route R_1, $DDRU$ (%) is the percentage of diluent recovered in the DRU, whereas $LDRU$ (%) is the LGO yield in the DRU. Both $DDRU$ and $LDRU$ are inputs to this energy model. Similarly, VTB_S is estimated from as follows

$$VTB_s = \sum_{s=1}^{j} (LF_s(ATB_s\,BSV_s\,(1 - LVDU - HVDU))) \tag{15}$$

where BSV_S (%) represents the bitumen split to the VDU in the SCO producers following route R_1, $LVDU$ (%) is the LGO yield in the VDU and $HVDU$ (%) is the HGO yield in the VDU. The terms BSV_S, $LVDU$, and $HVDU$ represent inputs into the model, and, thus, they need to be specified *a priori*. The hydrogen demand for hydrocracking in R_2 (DHI_{C2}) is calculated as follows

$$DHI_{C2} = \frac{HRF}{\rho_{H_2}} \sum_{s=1}^{j} (L_s(VTB_s + ATB_s))$$
$$L_s = \begin{cases} 1 & \text{if } s \text{ follows upgrading } R_2 \text{ in SAGD/Upgrading} \\ 0 & \text{otherwise} \end{cases} \tag{16}$$

where HRF (8,464 ft^3 H_2/tonne feed[13]) is a parameter that determines the hydrogen requirement in high-conversion LC-finers. Since upgrading R_3 is based on thermocracking, no hydrogen is consumed in bitumen cracking for this upgrading technology. The total hydrogen demand for hydrotreatment (DHI_{HYD}) in the SAGD/upgrading SCO producers is calculated as follows

$$DHI_{HYD} = \frac{1}{UC\,\rho_{H_2}} \sum_{s=1}^{j} \left(\frac{HRN\,N_s}{ND} + \frac{HRL\,LGO_s}{LD} + \frac{HRH\,HGO_s}{HD} \right) \tag{17}$$

where HRN (930 ft^3/bbl[38]), HRL (1,150 ft^3/bbl[38]) and HRH (1,150 ft^3/bbl[38]) are the hydrogen requirements for the hydrotreatment of naphtha, LGO and HGO, respectively. N_s, LGO_s and HGO_s are the naphtha, LGO and HGO products entering the hydrotreatment units, respectively. ND, LD and HD are the average densities of naphtha (ND = 0.744 tonne/m^3),[43] LGO (LD = 0.9125 tonne/m^3),[43] and HGO (HD = 0.9713 tonne/m^3),[43] respectively.

The process steam demand for integrated SAGD/upgrading SCO producers (DS_{SO}) is estimated as follows

$$DS_{SO} = \sum_{s=1}^{j} \Bigg(BI_s\,(1 + DR)\,SRD. + (ATBD_s - ATB_s)\,SRV + \frac{ATBF_s\,SRF}{LFD} \Bigg) \tag{18}$$

where DR is a parameter that defines the fraction of naphtha used as diluent, SRD (0.30 tonne steam/tonne feed[13]) is the steam requirement in the DRU, $ATBD_s$ (tonne/yr) is the ATB produced in the DRU, SRV (SRV = 0.07 tonne steam/tonne feed[13]) is the steam requirement in the VDU, $ATBF_s$ (tonne/yr) is the ATB entering the fluid coker, SRF (0.051 tonne steam/bbl feed[41]) is the steam requirement in the fluid coker, and LFD is the average feed density (0.1654 tonne/bbl[43]).

The power demand in the integrated SAGD/upgrading SCO producers is formulated as follows

$$DP_{SO} = (1 + ER_{GP}) \sum_{s=1}^{j} \left(\frac{VTB_s\ ERL}{LFD} + \frac{ATBF_s\ ERF}{FD} + \frac{VTBD_s\ ERD}{VD} \right) \tag{19}$$

where DP_{SO} is the total power demand, ERL (1.88e–3 kW·yr/bbl[44]) is the electricity requirement in LC-finers, FD (0.165 tonne/bbl[43]) is the average fluid coker feed density, ERF (6.85e–4 kW·yr/bbl[44]) is the electricity requirement in fluid coking, $VTBD_s$ is the VTB entering the delayed coker (tonne/yr), ERD (4.45e–4 kW·yr/bbl[13]) is the electricity requirement in delayed coking, and VD is the VTB density (0.168 tonne/bbl[43]). The process fuel demand (DF_{SO}) for these SCO producers is estimated as follows

$$DF_{SO} = \sum_{s=1}^{j} \left(\frac{VTB_s\ FRL}{H_{NG}\ LFD} + \frac{VTBD_s\ FRD}{H_{NG}\ VD} \right) \tag{20}$$

where FRL (0.093 GJ/bbl)[44] and FRD (0.153 GJ/bbl)[44] are the process fuel requirement in LC-fining and delayed coking, respectively.

Integrated mining/upgrading—SCO producers

The integrated mining/upgrading SCO producers were the first schemes employed to extract and upgrade the bitumen into SCO. It is estimated that around 20% of the bitumen reserves in the Athabasca region are mineable deposits.[1] These SCO producers consider different stages. The first step involves mining the bitumen from the oil sand whereas the remaining stages are used to separate the crude bitumen from the clay and sand (bitumen recuperation processes) followed by an upgrading scheme to upgrade the bitumen into SCO. The upgrading routes considered for this SCO producer are the same described in the Integrated SAGD/Upgrading SCO producers section. The energy demands required by these stages are discussed next. The total production of SCO via integrated mining/upgrading (TO_{MO}) is calculated as follows

$$TO_{MO} = \sum_{m=1}^{k} SCOS_m \tag{21}$$

where the subindex m represents the integrated mining/upgrading SCO producers included in the model, and $SCOS_m$ (bbl SCO/d) is the corresponding SCO production capacity by producer. This equation allows the model to select the appropriate production capacity and producer for integrated mining/upgrading, i.e., they are considered as decision variables in this energy optimization model.

Mining Extraction. This stage consists of mining the oil sand to recover the crude bitumen trapped in the oil sand mixture. This process is accomplished through the use of shovels and trucks. The energy demand in mining is the fuel consumed by the vehicles. The diesel consumption in the vehicles (D) is calculated as follows

$$D = \left(\frac{DRS}{MCS} + \frac{DRT}{MCT} \right) \sum_{m=1}^{k} MSR_m \tag{22}$$

where MSR_m (tonne of oil sand/yr) is the oil sand mining rate by producer, DRS (L/h) is the average diesel requirement for the shovels' fleet, MCS (tonne/h) is the shovels' mining capacity, DRT (L/h) is the average diesel requirement for the trucks' fleet, and MCT (tonne/h) is the trucks' capacity. The cost of the diesel (D_c) is estimated as follows

$$D_C = D\ \ DP \tag{23}$$

where DP ($/L) is the price of the diesel.

Conditioning. In this stage, hot water and process steam are injected to the mined oil sand to promote the separation between the crude bitumen molecules and the sand. The hot water demand (DW_{CON}) in this stage is calculated as follows

$$\begin{aligned} DW_{CON} &= WR_C \sum_{m=1}^{k} (LF_m SC_m MSR_m) \\ LF_m &= \begin{cases} 1 & \text{if } m \text{ follows upgrading } R_1 \text{ in Mining/Upgrading} \\ 0 & \text{otherwise} \end{cases} \\ SC_m &= \begin{cases} 1 & \text{if } m \text{ follows a producer with conditioning stage} \\ 0 & \text{otherwise} \end{cases} \end{aligned} \tag{24}$$

where WR_c (0.333 tonne water/tonne oil sand[41]) is the parameter that defines the hot water requirement in the conditioning stage. Similarly, the steam demand is as follows

$$DS_{CON} = SR_C \sum_{m=1}^{k} (LF_m\ SC_m\ MSR_m) \tag{25}$$

where DS_{CON} (tonne/yr) is the process steam demand in conditioning and SR_c (0.036 tonne steam/tonne oil sand[41]) is the steam requirement in conditioning.

Hydrotransport. In this stage hot water is added to the mined oil sand to create slurry that is transported via pipeline to the next processing stage (bitumen recovery). The energy demands in this stage are the hot water and the electricity required to pump the slurry to the recovery plant. The hot water demand (DW_H) for this process is formulated as follows

$$DW_H = WR_H \sum_{m=1}^{k} MSR_m \tag{26}$$

where WR_H (0.30 tonne water/tonne oil sand[13]) is the hot water requirement in hydrotransport. The power demand for this stage is calculated as follows

$$DP_{HT} = \sum_{m=1}^{k} (SL_m\ d_m\ PF_m) \tag{27}$$

where DP_{HT} is the power demand in hydrotransport, SL_m (tonne/yr) is the slurry rate, d_m (m) is the distance from the mine to the extraction plant and PF_m (Kw·yr/tonne/m) is a pumping factor that defines the power requirements necessary to transport the slurry rich in oil to the next stage.

Bitumen Recovery. In this stage, the bitumen is recovered from the slurry and considers two extraction processes: in the primary extraction the bitumen froth proceeding from the previous two stages is recovered using hot water and steam, whereas in the secondary extraction the froth is diluted in naphtha and centrifuged to remove the remaining water and sand traces from the bitumen. The hot water demand (DW_E) for bitumen recovery is calculated as follows

$$DW_E = WWR_E \sum_{m=1}^{k} MSR_m \tag{28}$$

where WWR_E (0.41 tonne water/tonne oil sand[41]) is the wash water for primary extraction. The steam demand in bitumen extraction (DS_E) is as follows

$$DS_E = SR_E \sum_{m=1}^{k} F_m \tag{29}$$

where SR_E (0.04 tonne steam/tonne froth[41]) is the steam requirement in bitumen extraction, and F_m (tonne froth/yr) is the bitumen froth produced in primary extraction. The electricity demand (DP_E) for this stage is calculated as follows

$$DP_E = \sum_{m=1}^{k} \left((TPE_m + TSE_m)\, dT_m\, PFT_m + DBC_m\, ERC\, CS \right) \tag{30}$$

where TPE_m and TSE_m (tonne/yr) are the tailings produced in primary and secondary extraction, respectively; dT_m (m) is the distance from the extraction plant to the tailing ponds; PFT_m (kW·yr/tonne/m) is the pumping factor to tailings; DBC_m (m^3/yr) is the diluted bitumen entering centrifuges; ERC (kW·yr/m^3) is the electricity requirement for diluted bitumen centrifugation, and CS is the centrifugation stages in the model ($CS = 2$[13]).

Upgrading. In this stage, the bitumen is upgraded to SCO using three different upgrading routes as described in the Integrated SAGD/Upgrading SCO producers section (see Figure 2). Hence, the associated energy demands in this stage for integrated mining/upgrading SCO producers are similar to those presented in the previous section. Accordingly, each individual energy demand for this stage is presented next. The hydrogen requirement for hydrocracking in producers following R_1 is estimated as follows

$$DHM_{C1} = \frac{HRLF}{\rho_{H_2}} \sum_{m=1}^{k} \left(LF_m\, (VTB_m + ATB_m) \right) \tag{31}$$

where DHM_{C1} is the hydrogen demand in R_1, VTB_m and ATB_m are the feed VTB and ATB streams to the LC-finer, respectively. The hydrogen demand for hydrocracking in R_2 (DHM_{C2}) is as follows

$$DHM_{C2} = \frac{HRF}{\rho_{H_2}} \sum_{m=1}^{k} \left(L_m (VTB_m + ATB_m) \right)$$
$$L_m = \begin{cases} 1 & \text{if } m \text{ follows upgrading } R_2 \text{ in Mining/Upgrading} \\ 0 & \text{otherwise} \end{cases} \tag{32}$$

The total hydrogen demand for hydrotreatment (DHM_{HYD}) in these SCO producers is defined as follows

$$DH_{HYD} = \frac{1}{UC\, \rho_{H_2}} \sum_{m=1}^{k} \left(\frac{HRN\, N_m}{ND} + \frac{HRL\, LGO_m}{LD} + \frac{HRH\, HGO_m}{HD} \right) \tag{33}$$

where N_m, LGO_m and HGO_m are the naphtha, LGO and HGO products entering hydrotreatment. The steam demand (DS_{MO}) for these SCO producers is calculated as follows

$$DS_{MO} = \sum_{m=1}^{k} \left(BI_m\, (1 + DR)\, SRD + (ATBD_m - ATB_m)\, SRV. + \frac{ATBF_m\, SRF}{LFD} \right) \tag{34}$$

where $ATBD_m$ (tonne/yr) is the ATB produced in the DRU and $ATBF_m$ (tonne/yr) is the ATB entering the fluid coker. The power demand (DP_{MO}) for integrated mining/upgrading producers is as follows

$$DP_{MO} = \sum_{m=1}^{k} \left(\frac{VTB_m\, ERL}{LFD} + \frac{ATBF_m\, ERF}{FD} + \frac{VTBD_m\, ERD}{VD} \right) \tag{35}$$

where $VTBD_m$ (tonne/yr) is the VTB entering the delayed coker. The process fuel demand (DF_{MO}) for mining/upgrading producers, and the total cost of the process fuel used in the entire operation (F_c) are calculated as follows

$$DF_{MO} = \sum_{m=1}^{k} \left(\frac{VTB_m\, FRL}{H_{NG}\, LFD} + \frac{VTBD_m\, FRD}{H_{NG}\, VD} \right) \tag{36}$$

$$F_C = t\, (DF_{SO} + DF_{MO})\, H_{NG}\, F_{NG} \tag{37}$$

Water Management. The integrated model presented in this work includes as key feature the freshwater consumption and water recycling that are needed to maintain the oil sands operations. Most of the freshwater used by the mining oil sand operators is employed to separate the crude bitumen from the clay and sand, i.e., conditioning, hydrotransport and bitumen recovery.[8] The freshwater is withdrawn from the Athabasca River under specific environmental restrictions, e.g., Alberta environment imposes a restriction on the maximum withdrawal of freshwater (10% of natural flow) in areas where this liquid is vital for the wellbeing and sustainability of aquatic ecosystems.[45] According to Allen,[8] the reduction of the river flow during winter represents a constraint for future developments and expansion of the oil sands, which indicates the necessity to include a plan for the optimal use of water. Moreover, the oil sands operate under a zero discharge policy, i.e., the operators has to store all process water and tailings on site.[8] This has led to the creation of the Athabasca region tailings ponds, i.e., waste materials from mining oil sands operations. Although significant improvements have been implemented to make an efficient use of this valuable natural resource, the recycling of the tailings ponds water represents a key alternative to reduce freshwater consumption in the oil sands operation. Recycled water represents around 70–85% of the water used in bitumen recovery processes. For example, Syncrude recycled 16.4 barrels of water per barrel of oil produced in 2004, whereas an average of 3.1 barrels of freshwater per barrel of oil produced was used by the three major mining companies during the same year.[8] In this model, water management was included in the model as follows

$$W_{MO} = W_{REC} + W_{FRESH} \tag{38}$$

$$W_{REC} = RF\,(DW_{CON} + DS_{CON} + DW_H + DW_E + DS_E + DES_{CB} + DES_{SO}) \tag{39}$$

$$S + HW + ES_{BE} - W_{REC} \le FWR \tag{40}$$

where W_{MO} (tonne/yr) is the amount of water used in the oil sands operations, W_{REC} (tonne/yr) is the amount of recycled water used by the oil producers, W_{FRESH} (tonne/yr) is the amount of fresh water imported from the Athabasca river, and *FWR* (tonne/yr) is the maximum amount of freshwater that can be withdrawn from the Athabasca River and represents an input into the model. The amount of fresh water imported in the operations is proportional to the amount of water loss in the system, such as tailing ponds. Thus, freshwater is only used to make up for the water losses in the process. *RF* (70–85%)[8] is a factor that determines the percentage of water recycled in the system. Furthermore, Eq. 40 accounts for the constraint on the annual maximum amount of freshwater that can be withdrawn from the Athabasca River. This amount of freshwater is considered in the model based on the average annual flow of the Athabasca River just downstream of Fort McMurray. The reference value of the annual river's natural flow is considered to be 633 m^3/s.[46] Typical values for *FWR* have been reported in the literature.[45]

Environmental restrictions

This energy optimization model includes energy commodity producers with and without CO_2 capture, which allows aiming for a specific CO_2 emission target in the oil sands operations. The total carbon dioxide emission (*ET*) of the Canadian oil sands operations is calculated as follows

$$ET = \sum_i E_i; \quad i = [p, h, B, BE, D, PF] \tag{41}$$

where E_i (tonne CO_2/yr) represents the carbon dioxide emissions from the different energy commodity producers or emissions generated when certain commodities are consumed, i.e., natural gas and diesel. The subindex *i* represents the set of energy producers and commodities that are used in the oil sands operations, i.e., power plants (*p*), hydrogen plants (*h*), process steam boilers (*B*), SAGD steam boilers (*BE*), diesel (*D*) and process fuel (*PF*).The carbon dioxide emission constraint included in this model is as follows

$$ET \le CET \tag{42}$$

where *CET* (tonne CO_2/yr) is the carbon dioxide (CO_2) emission constraint. This parameter is an input to the model, and it is usually defined in terms of a GHG emission target.

The electricity demands required to transport the CO_2 captured in power plants (DP_{cc}) to the corresponding storage facilities is calculated as follows

$$DP_{CC} = L\sum_{p=1}^{P}\left(PC_pC_pPRT_p\right)$$
$$PC_p = \begin{cases} 1 & \text{if power plant } p \text{ capture } CO_2 \\ 0 & \text{otherwise} \end{cases} \tag{43)}$$

where C_p (tonne CO_2/yr) is the CO_2 captured in power plants, PRT_p (kW·yr/tonne CO_2/km) is the compression power for CO_2 transport and *L* is the length of a pipeline used to transport the CO_2 from Fort McMurray to depleted oil fields near Edmonton, Ontario ($L \approx 600$ Km).

The electricity required to transport the CO_2 capture from the hydrogen plants (DP_T) is estimated as follows

$$DP_T = L\sum_{h=1}^{H}(HC_hC_hPRT_h)$$
$$HC_h = \begin{cases} 1 & \text{if hydrogen plant } h \text{ capture } CO_2 \\ 0 & \text{otherwise} \end{cases} \tag{44}$$

where C_h (tonnes CO_2/yr) represents the amount of CO_2 captured in hydrogen plants and PRT_h is the compression power required for CO_2 transportation.

The transportation costs of the CO_2 captured in power and hydrogen plants is formulated as follows

$$T_C = TC\,L\left(\sum_{h=1}^{i}(HC_hC_h) + \sum_{p=1}^{h}\left(PC_p\,C_p\right)\right) \tag{45}$$

where T_c (\$/year) is the annual CO_2 transportation cost and *TC* (\$/tonne CO_2/km) is the unitary CO_2 transport cost. The annual CO_2 sequestration cost (ST_c) is calculated as follows

$$ST_C = SC\left(\sum_{h=1}^{i}(HC_h\,C_h) + \sum_{p=1}^{h}\left(PC_p\,C_p\right)\right) \tag{46}$$

where *SC* (\$/tonne CO_2) is an input parameter that represents the CO_2 sequestration cost.

Total energy commodity requirements

The total energy commodity requirements are represented by the addition of the individual energy consumptions in every stage involved in commercial crude bitumen production and SCO production (see Commercial Crude Bitumen Production, Integrated SAGD and Mining/Upgrading SCO producers sections). Accordingly, these requirements are estimated as follows

$$P = \sum_e DP_e; \quad e = [CC, h, T, CB, SO, HT, E, MO] \tag{47}$$

$$H = \sum_f DHI_f + DHM_f; \quad f = [C1, C2, HYD] \tag{48}$$

$$S = \sum_l DS_l; \quad l = [SO, CON, E, MO] \tag{49}$$

$$HW = \sum_r DW_r; \quad r = [CON, HT, E] \tag{50}$$

$$ES = \sum_t DES_t; \quad t = [CB, SO] \tag{51}$$

$$F = \sum_u DF_u; \quad u = [SO, MO] \tag{52}$$

where *P, H, S, HW, ES* and *F* are the total requirements of power, hydrogen, process steam, hot water, SAGD steam, and process fuel (natural gas), respectively. The total diesel demand is obtained from Eq. 22. DP_e, DS_l, DW_r, DES_t and DF_u represent the individual demands of power, process steam, hot water, SAGD steam, and process fuel, respectively. Moreover, DHI_f and DHM_f are the individual demands of hydrogen for integrated SAGD/upgrading and mining/upgrading SCO producers, respectively. The subindices e, f, l, r, t and u represent sets that group the SCO producers, upgrading routes, production stages, and commodity producers associated with the energy commodity requirements for the production of commercial crude bitumen and SCO, respectively. The subindices are specified by the integrated SAGD/upgrading SCO producers (SO), the integrated mining/upgrading producers (MO), the commercial bitumen producer (CB), the upgrading route R_1 ($C1$), the upgrading route R_2 ($C2$), the conditioning stage (CON), the hydrotransport stage (HT), the bitumen recovery stage (E), the hydrotreatment stage (HYD), carbon dioxide capture (CC), carbon dioxide transport (T), and hydrogen plants (h), respectively.

Energy commodity supply constraints

The total energy commodity requirements in the model must be satisfied by the energy commodity producers. Consequently, the following energy constraints that relate the total costs to the total commodity demands are included in the model

$$P \leq \sum_{p=1}^{h} G_p + \sum_{h=1}^{i} \left((1 - HS_h)\, G_h \right) \tag{53}$$

where G_h is the power cogenerated by coal gasification hydrogen plants (kW)

$$H \leq \sum_{h=1}^{i} \left(\frac{FD_h\, H_h}{HEAT_h} \right) \tag{54}$$

where $HEAT_h$ is the heating rate required to produce one tonne of H_2 (MJ/tonne H_2) per hydrogen plant type h

$$ES \leq ES_{BE} + ES_N \tag{55}$$

The aforementioned constraint specifies that the total amount of SAGD steam produced by the boilers and nuclear plants must be greater or equal than the total demand of SAGD steam in the oil sands operations.

Cost function and optimization variables

The model's cost function (*cost*) represents the annualized energy supply costs for the oil sands operations. The cost function is estimated from the costs of individual energy commodities needed by the SCO and crude bitumen producers. Also, the cost function accounts for the associated environmental costs for CO_2 capture and sequestration. Accordingly, the model's cost function used in this energy optimization model is as follows

$$Cost = P_C + H_C + S_C + HW_C + ES_{BC} + ES_{NC} + F_C + D_C + T_C + ST_C \tag{56}$$

where the terms in Eq. 56 represent the following production and supply costs: Power (P_c), hydrogen (H_c), process steam (S_c), hot water (HW_c), SAGD steam from boilers (ES_{BC}), SAGD steam from nuclear plants (ES_{NC}), process fuel (F_c), diesel (D_c), CO_2 transport (T_c), and CO_2 underground sequestration (ST_c). Each of these individual cost functions has been explicitly defined in the previous sections. The model's set of decision variables (η) is as follows

$$\eta = \left[P_p, N_h, NB, NBE, N_N, EPC, PSI_s, SCOI_s, PSS_m, SCOS_m \right] \tag{57}$$

where P_p is the number of power plants, N_h the number of hydrogen plants, NB the number of boilers producing process steam and hot water, NBE the number of boilers producing SAGD steam, N_N the number of Toshiba's 4S nuclear facilities producing SAGD steam, EPC the energy commodity producers' operating conditions, PSI_s represents the integrated SAGD/upgrading SCO producers, $SCOI_s$ is the SCO production capacity by SAGD/upgrading producer, PSS_m represents the integrated mining/upgrading SCO producers, and $SCOS_m$ is the SCO production capacity by mining/upgrading producer.

The optimization model presented in this work searches for the commodity energy producers, commercial crude bitumen production and SCO producers that minimize the total annual operating cost of the oil sands under a CO_2 emission constraint. The resulting optimization model is a mixed integer nonlinear program (MINLP) that was implemented in GAMS. To simplify the model's complexity, the nonlinearities that result from the multiplication of a binary variable with a continuous variable were linearized applying the exact linearization scheme described by Torres[48] and Oral and Kettani.[49] To illustrate the linearization scheme (Eq. 3), which includes a nonlinear term due to the multiplication of the binary variable HS_h, with the continuous variable H_h, (see Eq. 3) is linearized as follows[48–49]

$$DP_H = \sum_{h=1}^{H} (\lambda_h\, ES_h) \tag{58}$$

where the variable λ_h is defined as follows

$$\lambda_h = HS_h\, H_h \tag{59}$$

Note that λ_h is just a definition, i.e., it is not formally implemented in the optimization formulation. Also, two constraints are added in the formulation, i.e.

$$0 \leq \lambda_h \leq H_h \tag{60}$$

$$H_h - H_h^{\max}\,(1 - HS_h) \leq \lambda_h \leq H_h^{\max}\, HS_h \tag{61}$$

where $H_h^{\max}$ (tonne H_2/yr) is the maximum installation capacity for the hydrogen plants. The remaining equations that contain nonlinear terms in the binary variable were linearized in the same fashion and are not shown here for brevity.

Although several solvers are available in the GAMS platform to solve MINLP optimization problems, e.g., Baron, Coinbonmin, Coincouenne, Dicopt, Emp, this energy model formulation was solved using Dicopt.[50] This MINLP solver was used because is based on the extensions of the outer-approximation algorithm for the equality relaxation strategy[51] that only requires a user-supplied starting point for the nonlinear subproblem (NLP). Therefore, Dicopt is more flexible when compared to others MINLP solvers in GAMS, e.g., Baron requires a feasible user-supplied starting point. Also, according to a study that compares high-performance MINLP solvers, Dicopt is ranked as one of the most computationally efficient MINLP optimization solvers,[52] i.e., Dicopt and Baron required an averaged CPU time of 1.4 and

Table 2. Key Economic Parameters for the Model

Parameters[a]	Units	Value
Boiler feed water cost	\$/tonne	1.5
Natural gas cost	\$/GJ	12.0
Coal cost	\$/GJ	3.0
Diesel cost	\$/l	1.5
CO_2 transport cost	(\$)(100 Km)/tonne CO_2	1.40
CO_2 injection cost	\$/tonne CO_2	8.0
Natural gas heating value	MJ/Nm^3	38.05
Coal heating value	MJ/Kg	24.05
Heat for process steam (B)	MJ/tonne steam	3,415
Heat for SAGD steam (BE)	MJ/tonne steam	2,469
Nuclear Facilities for SAGD steam (NFE)	tonne steam/h	41.55
Boiler capacity	tonne steam/h	340
Annual operating hours	h/yr	8,760
Boiler's capacity for process steam	%	0.82

[a]B = Natural gas boilers for process steam at 6,300 kPa and 500°C, BE = Natural gas boilers for SAGD steam at 80% quality and 8,000 kPa.
NFE = Nuclear facilities for producing SAGD steam at 500°C and 10 MPa.

5.8 min to solve 250 benchmarks MINLP problems, respectively. Moreover, studies have shown that, on average, the outer-approximation algorithm lead to savings in computational time of approximately 40 and 74% with respect to generalized Benders and branch and bound (e.g., Baron),[51,53] respectively. Furthermore, the linearization scheme presented earlier increase the efficiency of the MINLP solver implemented in the energy model since Dicopt was especially developed to handle programming problems that are linear in the binary variables.[48,53]

The MINLP algorithm implemented by Dicopt performs a series of nonlinear (NLP) optimization subproblems and mixed integer (MIP) subproblems that can be solved using any nonlinear (NLP) or mixed integer program (MIP) solver that works under the GAMS system. For this work, MINOS was used as the NLP solver, whereas CPLEX was used to solve the MIP subproblems. These are two of the most common solvers used by default to handle the NLP and MIP subproblems when implementing Dicopt as MINLP solver.[47,51] This comprehensive model can be used for planning and scheduling of the future operations of the oil sands under different scenarios, e.g., nuclear facilities for power and SAGD steam production, water management and carbon dioxide emission restrictions.

Case Study 2030

The integrated energy model presented in the previous section was used to determine the oil sands production for year 2030 under different scenarios. This year was selected because a study that reports the expected oil sand producers and their corresponding production capacities, the energy commodity requirements, the energy commodity producers' configuration, and the unitary energy costs of SCO and commercial bitumen production is available in the literature.[17] The information presented in that study was used to validate the energy model presented in the previous section. Likewise, the results presented by that study, obtained for fixed SCO producers and capacities, were compared to those obtained by this model, where the SCO producers and capacities are considered as optimization variables. These two scenarios, where the inputs to the model were obtained from a previous simulation study[17] are referred to from thereafter as the *Reference Case 2030*.

Similarly, a recent report by McColl et al.[54] has provided with new estimates for the oil production and fuel costs forecast for 2030. These new estimates have been used in this study to provide a more realistic scenario for the oil Sands operation. Additionally, the oil producers and energy commodities configurations for 2030 were determined with and without a CO_2 emission constraint. These two scenarios, where the new SCO and crude bitumen production estimates are used in the model, are referred to from thereafter as the *Updated Case 2030*. The key economic parameters for the energy model are shown in Table 2.[17]

Table 3. Energy Commodity Producers

Energy producer[a]	Source
Boilers	
NG-at 6,300 kPa and 500 °C steam-w/o CO_2 capture (B)	(Harrel, 2002)
NG-80% steam at 8,000 kPa-w/o CO_2 capture (BE)	(Harrel, 2002)
Nuclear Energy Facility (SAGD steam)	
Toshiba 4S Nuclear Plant (NFE)	(McColl et al., 2008)
Power plants	
NGCC w/o CO_2 capture (E_1)	(Rubin, Rao& Chen, 2004)
Supercritical coal w/o CO_2 capture (E_2)	(Rubin, Rao& Chen, 2004)
IGCC w/o CO_2 capture (E_3)	(Ordorica, Douglas, Croiset & Zheng, 2006)
IGCC with 88% CO_2 capture via Selexol (E_4)	(Ordorica, Douglas, Croiset & Zheng, 2006)
IGCC with 88% CO_2 + H_2S co-capture via Selexol (E_5)	(Ordorica, Douglas, Croiset & Zheng, 2006)
NGCC with 90% CO_2 capture via MEA (E_6)	(Rubin, Rao & Chen, 2004)
Supercritical coal with 90% CO_2 capture via MEA (E_7)	(Rubin, Rao & Chen, 2004)
NG Oxyfuel with CO_2 capture (E_8)	(Davison, 2007)
Coal Oxyfuel with CO_2 capture (E_9)	(Davison, 2007)
Nuclear Plant ACR-700 (E_{10})	(Thomas, S, 2005)
Nuclear Plant EPR-1600 (E_{11})	(Thomas, S, 2005)
Nuclear Plant ACR-1000 (E_{12})	(Thomas, S, 2005)
Hydrogen plants	
SMR w/o CO_2 capture (HG_1)	(Simbeck& Chang, 2002); (Simbeck, 2004)
SMR with 90% CO_2 capture via MEA (HG_2)	(Simbeck& Chang, 2002); (Simbeck, 2004)
Coal gasification w/o CO_2 capture (HG_3)	(Chiesa et al., 2005); (Kreutz et al., 2005)
Coal gasification with 90% CO_2 capture via Selexol (HG_4)	(Chiesa et al., 2005); (Kreutz et al., 2005)
Coal gasification with 90% CO_2 + H_2S co-capture via Selexol (HG_5)	(Chiesa et al., 2005); (Kreutz et al., 2005)

[a]NG = Natural Gas, NGCC = Natural Gas Combined Cycle power plants, IGCC = Integrated Gasification Combined Cycle power plants, SMR = Steam Methane Reforming hydrogen plants, MEA = Mono-ethanolamine.

Table 4. Energy Producers Modeling Factors

Energy Producer	Installed Capacity	Capital Cost	Economic Factor for O&M Costs	Fuel Rate
Boilers	(tonne/h)	($/kW)	(% Capital cost)	(MJ/tonne)
B	340	—[NS]	—[NS]	3,415
BE	340	—[NS]	—[NS]	2,470
Nuclear SAGD steam plant	(MWh)	($/MWh)	($/MWh)	(MWh/kg)
NFE	30	930,000	0.558	360
Power plants	(kW)	($/kW)	(% Capital cost)	(MJ/kWh)
E_1	507,000	570	0.018	7.17
E_2	524,000	1,230	0.038	9.16
E_3	539,000	1,760	0.026	8.76
E_4	448,000	2,400	0.025	11.06
E_5	513,000	1,890	0.026	10.17
E_6	432,000	930	0.037	8.41
E_7	492,000	1,980	0.049	12.04
E_8	440,000	1,250	0.086	7.70
E_9	532,000	1,950	0.076	9.72
Nuclear Power plants	(MWh)	($/kW)	($/kWh)	(MWh/kg)
E_{10}	1,406	2,056	0.0094	360
E_{11}	1,500	2,480	0.000465	360
E_{12}	2,170	2,657	0.000465	360
Hydrogen plants	(tonne/h)	(MM$)(h)/tonne$H_2$	(% Capital cost)	(MJ/tonneH_2)
HP_1	6.25	11,13	0.060	174,900
HP_2	6.25	17,76	0.060	204,200
HP_3	32.09	23,78	0.036	209,000
HP_4	32.09	25,07	0.036	209,000
HP_5	32.09	23,4	0.036	209,000

[NS]the capital costs of the boilers (B and BE) do not significantly contribute to the costs associated with the production of process steam, hot water and SAGD steam.

Note: HP_3, HP_4 cogenerate 2,240 and 1,210 kWh/tonne H_2, respectively.

Reference case 2030: model validation

The data available in the literature for the year 2030[17] was initially used to validate the energy optimization model presented in this work. Table 3 shows the energy commodity producers used for the model validation, i.e., power plants (E_1-E_9), hydrogen plants (HG_1-HG_5), process steam (B) and SAGD steam (BE) boilers. Accordingly, the number of power and hydrogen plants were set to 9 ($P = 9$), and to 5 ($H = 5$), respectively. Additionally, Table 4 shows the key characteristics of the energy commodity producers and Table 5 shows a summary of the energy commodities consumed in each processing stage of the oil producers. The model validation did not include nuclear plants or water management because they were not considered in the previous study.[17] However, these two key aspects of the future oil sands operations have been considered in the *Updated Case 2030* scenario (see the Updated Case 1-2030 and Updated Case 2-2030 sections). The number of units available in the model per type of commodity producer was considered to be approximately four times of that required to supply the oil sands energy demands in 2003.[14]

The optimization model was validated assuming that the SCO producers and their production capacities were fixed to constant values. Therefore, the SCO producers (see Table 1, PSI_1-PSI_3 and PSS_1-PSS_4) and their corresponding production capacities (see Eqs. 10 and 21, $SCOI_1$-$SCOI_3$ and $SCOS_1$-$SCOS_4$) for the integrated SAGD and mining/upgrading SCO productions were considered as inputs into the model for the model validation step. Consequently, the number of SAGD/upgrading SCO producers S was set to 3, whereas the number of mining/upgrading producers M was set to 4. Also, the commercial crude bitumen production was considered to be obtained by SAGD extraction for the model validation (see Table 1, *CBP*). The CO_2 emission was included as an input according to information reported in a previous study.[17] Furthermore, the model validation considered that natural gas is the only process fuel included in the analysis.

Since the oil producers and their corresponding capacities are assumed to be inputs to the model, the energy commodity requirements for the SCO and commercial bitumen producers were calculated by the model and remained fixed during the energy model's execution. The validation step consists of searching for the most suitable commodity producers' configuration (and their corresponding capacities) that meets the SCO and commercial bitumen's energy commodity requirements at minimum cost. This optimization model approach where the SCO producers are treated as inputs will be referred to in this work as the *sequential approach*. It should be noticed that the model presented in the Optimization Model section represents an integrated energy model because it considers the SCO producers and their production capacities as optimization variables. Thus, the integrated model offers the potential to find a more economically attractive scenario for the oil sands operations. However, in this scenario, the integrated model has been simplified to the sequential approach only for comparison

Table 5. Oil Producers Commodity Consumption Characteristics

Oil Producer	Extraction Method	Processing Stages: Conditioning	Hydrotreatment	Diluted Bitumen Extraction	Upgrading
PSS_1	**Mining** •D	•HW •S	•HW •P	•HW •S •P	•H •S •P •PF
PSS_2	**Mining** •D	—[NI]	•HW •P	•HW •S •P	•H •S •P •PF
PSS_3	**Mining** •D	—[NI]	•HW •P	•HW •S •P	•H •S •P •PF
PSS_4	**Mining** •D	—[NI]	•HW •P	•HW •S •P	•H •S •P •PF
PSI_1	**SAGD** •ES •P	—[NI]	—[NI]	—[NI]	•H •S •P •PF
PSI_2	**SAGD** •ES •P	—[NI]	—[NI]	—[NI]	•H •S •P •PF
PSI_3	**SAGD** •ES •P	—[NI]	—[NI]	—[NI]	•H •S •P •PF
CBP	**SAGD** •ES •P	—[NI]	—[NI]	—[NI]	—[NI]

[NI]The processing stage is not included in the corresponding oil producer.

Table 6. Results for the Reference Case 2030

Variables	Units	Ordorica-Garcia et al[17]	Reference Case 2030 (Sequential)	Reference Case 2030 (Integrated)
Energy Demands				
Power	MWh	3,220	3,307	2,566
Process Steam	tonne/h	17,296	17,312	18,679
SAGD Steam	tonne/h	49,703	49,001	42,048
Hot Water	tonne/h	100,655	102,360	110,490
Diesel	l/h	153,934	156,550	169,240
Hydrogen	tonne/h	609	610	607.4
Process fuel (NG)	GJ/h	10,204	10,362	6,104
Energy Producers				
E_1	Units	0	0	1
E_2	Units	5	5	3
HG_1	Units	1	1	0
HG_3	Units	8	8	10
HG_4	Units	14	14	13
Unit Energy Costs				
SAGD SCO	$/bbl	21.9	22.67	22.26
Mined SCO	$/bbl	20.2	20.92	19.39
SAGD Bitumen	$/bbl	10.0	9.97	9.96
Total Energy Cost	MM$/yr	–	35,455.63	33,687.31

purposes with the information reported in the literature.[17] The proposed energy model consists of 906 continuous variables and 27 integer variables. The integer variables consist of the types of energy producers and oil producers considered in the model.

The results obtained with the sequential approach for 2030 are shown in Table 6. As shown in this table, the energy commodity requirements, energy producers' configuration and energy supply cost per barrel of SCO and commercial bitumen production are in reasonable agreement with those reported in a previous study.[17] Therefore, the energy model proposed in this work describes the essential aspects of the oil sands operations reported in the literature. Accordingly, the energy model shown in the Optimization Model section can be used to determine future energy production costs and study possible upcoming scenarios for the oil sands operations.

Reference Case 2030: Integrated approach

The objective of this scenario is to show the potential (economic) benefits that can be obtained when the integrated energy model is applied to determine simultaneously the most suitable oil producers and the energy producers' infrastructure for the future operation of the oil sands. Accordingly, the reference case 2030 was redone assuming that the *total SCO and commercial bitumen production* are the only inputs provided to the energy optimization model. That is, the integrated model will search for both the set of SCO producers and energy commodity producers (and their corresponding capacities) that will meet the oil sands producers' energy requirements at the lowest energy cost. Thus, the integrated model approach expands the optimization algorithm's search space to consider attractive oil producers and energy commodity configurations that may result in more economical scenarios than those obtained by the sequential model approach. For comparison purposes, this scenario was solved under a CO_2 constraint equal to that considered in the model validation.[17] In this integrated approach, the SCO producers were limited to have a minimum production capacity (150,000 bbl/d each one). This was done to represent the production scenario expected for 2030, where the majority of the current technologies employed to produce SCO will still be in use. Likewise, the SCO and commercial bitumen producers as well as the commodity producers considered in this scenario were the same to those used in the model validation.

Table 6 shows a summary of the results obtained for this integrated scenario. As shown in the table, the integrated approach returned a cost that is 1,768 MM $/year (≈5%) lower than the cost obtained with the sequential approach. Thus, the integrated strategy implemented by this energy optimization model returns a more economically attractive solution than that obtained with the sequential approach. Table 6 also shows that the integrated approach returns average unitary energy costs of SCO per type of producer that are 1.81% (mined SCO) and 7.31% (SAGD SCO) less expensive than those obtained by the sequential method, respectively. The average unitary cost of the commercial crude bitumen remained unchanged because both the integrated and the sequential approach considered SAGD extraction as the only production method for commercial crude bitumen. Figure 3 shows the SCO producers' distribution specified by the sequential approach and the integrated approach, respectively. As shown in this figure, PSS_1 and PSI_2 are the two preferred producers

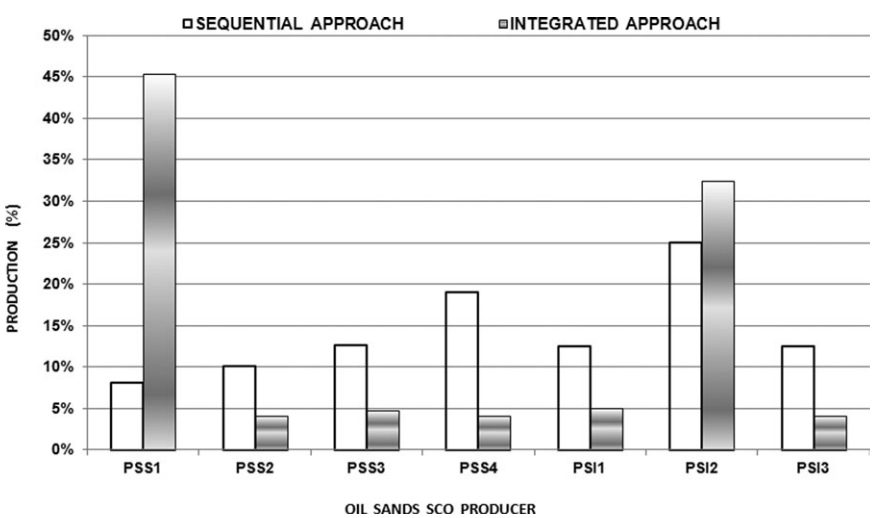

Figure 3. Comparison of SCO producers between the reference case 2030 (sequential approach), and reference case 2030 (integrated approach).

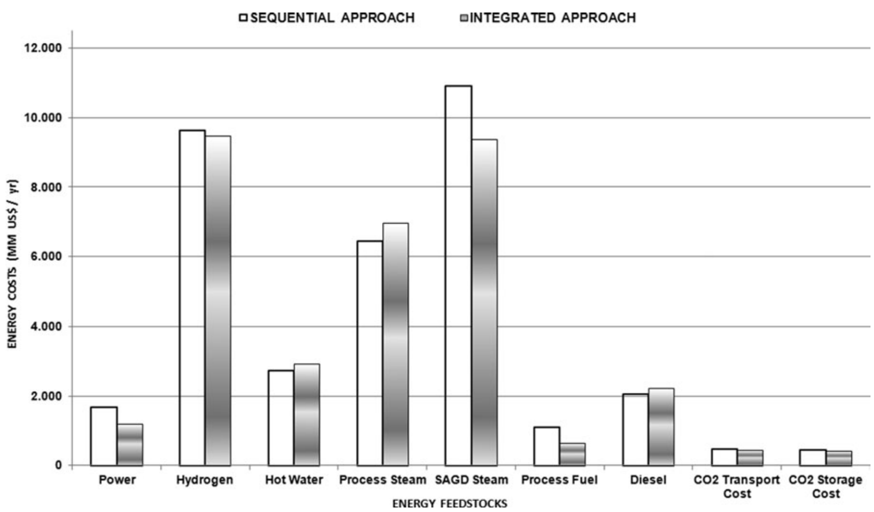

Figure 4. Comparison of the energy costs between the reference case 2030 (sequential approach), and reference case 2030 (integrated approach).

selected by the integrated approach since they contribute with approximately 45 and 32% of the total SCO production, respectively. This result suggests that SCO producers that consider hydrocracking (LC-fining) are regarded as the most suitable producers to be selected by this energy optimization model.

PSI_2 (see Table 1 and Figure 3) was selected as the most suitable integrated SAGD/upgrading SCO producer because it is based on hydrocracking (Route R_2), which has the highest conversion between these types of SCO producers. Also, hydrocracking processes usually yield higher SCO conversion than thermocracking processes.[55] Hydrocracking is a process wherein heavy oil feedstock is cracked in the presence of hydrogen. On the other hand, thermocracking is a process where the heavy oil is cracked under high-temperature conditions using natural gas as fuel (in this model). Hydrogen production is one of the least expensive processes included in this energy model because it can be produced using coal gasification plants, which uses coal as feedstock to produce hydrogen. Coal is an economic fuel, i.e., the price of coal is 4 times less costly than the cost of natural gas in the reference case 2030 (see Table 2). Also, the coal gasification hydrogen plants considered in the model cogenerate power, which makes the production of hydrogen via gasification more economically attractive but also more efficient. Cogeneration is currently considered in the Oil Sands as a suitable technology to optimize energy production by using the output of one process, i.e., hydrogen generation, to drive turbines that provide power. PSI_1 is the second preferred SAGD/Upgrading producer in the optimization model because it also uses hydrocracking as part of its upgrading route (R_1). PSI_3 is the least favored of these types of producers because it is based on thermocracking which is a process that uses intensively natural gas (NG), an expensive process fuel, to crack the heavy bitumen.

On the other hand, PSS_1 (see Table 1 and Figure 3) was selected as the main integrated mining/upgrading SCO producer by the integrated energy model. Although PSS_2 is also based on the same upgrading route (R_1), this was not selected as an important SCO producer because it includes in the bitumen recuperation process an extra stage when compared to PSS_1. This additional stage is conditioning, which treats 25% of the total bitumen being processed by this SCO producer before it is sent to the hydrotransport process. The remaining 75% of the bitumen is directly sent to hydrotransport (see Table 1 and Figure 3). Conditioning implies extra commodity requirements, i.e., hot water and process steam. These factors have motivated the selection of PSS_1 over PSS_2 in this energy model. Accordingly, the production capacity of PSS_2 remains close to the minimum allowed capacity. The producer PSS_4 was also selected to remain close to its minimum capacity because it is based on thermocracking as upgrading route (R_3). This route considers delayed coking, which relies on process fuel to generate heat and crack the heavy oil into lighter oil compounds. Thus, PSS_4 requires almost nine times more process fuel than that needed by PSS_1. PSS_3 was selected as the second SCO producer in the integrated mining/upgrading producers because it is based on hydrocracking, which uses hydrogen that can be produced at low cost using coal gasification. However, PSS_3 only produces 4.75% of the total SCO because it demands process fuel in a proportion of 4:1 when compared to PSS_1. Also, the distance to the bitumen extraction plant was considered to be 6 times larger in PSS_3 than in PSS_1. Thus, the electricity requirements to pump the slurry to the extraction plant are also higher for PSS_3 than for PSS_1.

Figure 3 shows that the majority of SCO is produced by PSS_1. This result is consistent with information reported in the literature that suggests that mining bitumen extraction has been historically less expensive than SAGD extraction.[56–57] Therefore, the integrated mining/upgrading SCO producers are expected to be less expensive than integrated SAGD/upgrading producers. The trend is likely to hold given that SAGD extraction is a thermal extraction method which requires large amounts of steam; traditionally in a ratio of 2.4–3 tonnes of steam per tonne of bitumen for most producers.[36] However, it is estimated that about 80% of the bitumen deposits in the Athabasca region need *in situ* extraction methods to be recovered.[1,54] Therefore, SAGD extraction will play an important role in the future operation of the oil sands because it is projected to become the leading bitumen extraction method in the short-term future.

As shown in Figure 4, the major commodity cost reductions as a result of using the integrated approach in comparison with the sequential approach are those associated with the production of SAGD steam (1,552 MM $/yr), power (467 MM $/yr), and process fuel (448 MM $/yr). The electricity demands in the integrated approach are mainly covered by coal power plants without CO_2 capture (E_2). The cost distribution shown in Figure 4 indicates that for the integrated approach, hydrogen production is the most significant energy cost closely followed by the costs of SAGD steam generation and process steam generation, respectively. SAGD steam represents the most important energy commodity employed for commercial bitumen production and it is also extensively used in SAGD SCO production (PSI_2). Moreover, process steam is highly used in the oil sands operations because it is extensively employed in integrated mining/upgrading (PSS_1), i.e., hydrotransport, bitumen recovery and upgrading stages. The integrated energy optimization model focuses on reducing the amount of SAGD steam employed in the operations because this is produced via natural gas boilers, which is one of the most expensive processes considered in this energy model.

Updated case 1-2030: Scenario without CO_2 constraints

The two scenarios considered in the previous sections used the reference case 2030 data reported in a previous study.[17] The reference case 2030 data was useful because it has sufficient information to validate this energy model and to show the potential benefits of using an integrated energy modeling approach like that used in this energy optimization formulation. However, the Canadian Energy Research Institute (CERI) has recently reported new estimates for the 2030 oil sands production[54] that are significantly different from those reported for the reference case 2030.[17] Also, the study from where the reference case 2030 data was obtained did not consider nuclear energy as an alternative energy commodity producer and water management in the formulation.

On the aforementioned basis, the integrated energy model presented in this work is applied to determine the most suitable oil producers and energy commodities configuration that returns the lowest energy cost using the new estimates for the 2030 oil sands operations. This scenario is referred to as the updated case 2030. Also, nuclear energy plants and the use of water recycling in the operations are explicitly included in the updated case 2030 scenario. To the author's knowledge, this is the first study that includes nuclear energy and water management in an energy model for oil sands operations. Accordingly, the number of power producers *P* in this case study was set to 12 which include nuclear power plants (see Table 3 and 4, E_1-E_{12}). The number of nuclear power plants included in the model is 2 per nuclear technology, i.e., there are three types of nuclear plants considered in the model. Likewise, the number of hydrogen plants *H* was set to 5; the number of SAGD/Upgrading SCO producers *S* was set to 3, and the number of mining/upgrading producers *M* set to 4. Moreover, SAGD steam production via nuclear energy facility is also available in this scenario (see Table 3, *NFE*). The number of SAGD steam nuclear plants considered in the model is 50. Process steam boilers (*B*), and SAGD steam boilers (*BE*), are also included in this scenario. The percentage of diluent recovered in the DRU *DDRU* was set to 98%, the *LGO* yield in the DRU *LDRU* was set to 12%, the *LGO* yield in the VDU *LVDU* was set to 7%, the HGO yield in the VDU *HVDU* was set to 26%, and the factor *RAF* was set to zero (0) (no individual-risk perception). The restriction on the withdrawal of freshwater from the Athabasca River *FWR* was considered to be 1.996e9 tonne/yr. The fuels' cost for this case study were updated according to the new estimates for the year 2030, i.e., natural gas = 11.06 \$/GJ[54] and coal = 1.96 \$/GJ.[58]

In this scenario, the CO_2 emission constraint (39), and the economic terms in the model's objective function related to this process were neglected, i.e., carbon dioxide transport cost (T_c), and underground sequestration cost (ST_c). The minimum expected capacities per type of producer in the oil sands for 2030, i.e., $SCOI_1$–$SCOI_3$ and $SCOS_1$–$SCOS_4$, were defined in the model according to estimates reported in the literature.[5,59–63] The new 2030 estimates expected for the total SCO production via integrated SAGD/upgrading and mining/upgrading and the commercial bitumen production (*CBP*) are[5]: 1 MM, 1.8 MM and 1.5 MM bbl/d, respectively.

The results obtained by the integrated energy model for this scenario are shown in Table 7. As shown in this table, the producers that include upgrading technologies considering hydrocracking as partial or complete cracking method (R_1 and R_2) are preferred over those that do not consider this method, e.g., R_3 (delayed coking). This is because hydrogen production is one of the most economically attractive processes in the model since coal gasification is available in the model. This technology uses coal as feedstock to generate hydrogen, which is 5.6 times less expensive than natural gas for this scenario. Natural gas is intensively used in thermocracking based producers (R_3). Thus, for integrated mining/upgrading producers, PSS_1 remains as the most suitable SCO producer since it includes mining extraction, which is more economical than SAGD extraction,[56–57] and hydrocracking (R_1), respectively. As in the previous scenario, PSS_1 remains as the main SCO oil producer for the year 2030. Thus, it is expected that this technology will be the dominant SCO production technology in the upcoming years. Accordingly, efforts must be made to enhance the efficiency of this process to make it more attractive. On the other hand, PSS_2 is one of the oldest, less energy efficient and expensive producers used in the oil sands industry. This is because it includes an extra processing stage, conditioning, which is a poor energy efficient process when compared to the rest of the integrated mining/upgrading producers. The new report on the oil sands operations does not foresee the use of this technology in the future. Accordingly, this energy model did not select PSS_2 to produce SCO.

PSS_4 is the second most important Mined SCO producer selected by the energy model. The selection of PSS_4 agrees with recent reports that show that this technology will be one of the dominant producers in the future.[5,59–63] PSS_3 is regarded as the minor SCO producer selected in this scenario according to the information considered in this work. The production level of PSS_3 remains at the minimum allowed capacity (see Table 7). As in the previous scenario, PSI_2 remains as the leading integrated SAGD/upgrading producer. This is because it includes one of the highest crude bitumen to SCO conversion processes considered in this energy model. Also, this technology is based on hydrocracking as an upgrading route (R_2). PSI_2 did not reach a higher production capacity in this scenario because less SCO will be produced via integrated SAGD/upgrading than with the mining/upgrading producers. This is according to information provided in the literature[54] and considering that the commercial crude bitumen is produced only via SAGD extraction in the model. Although SAGD is expected to dominate over Mining extraction in the upcoming future,[1,54] a large proportion of the crude bitumen produced via SAGD in 2030 is

Table 7. Results for the Updated Case 2030

Variables	Units	Scenario w/o CO_2 emission constraint	Scenario with CO_2 emission constraint	Scenario with CO_2 emission constraint & Nuclear penalty ($RAF = 20$)	Scenario with CO_2 emission constraint & Nuclear penalty ($RAF = 385$)
Producers					
PSS_1	bbl/d	1,000,000	1,000,000	1,000,000	1,000,000
PSS_2	bbl/d	0	0	0	0
PSS_3	bbl/d	350,000	350,000	350,000	350,000
PSS_4	bbl/d	450,000	450,000	450,000	450,000
Total Mined SCO	bbl/d	1,800,000	1,800,000	1,800,000	1,800,000
PSI_1	bbl/d	200,000	200,000	200,000	200,000
PSI_2	bbl/d	600,000	600,000	600,000	600,000
PSI_3	bbl/d	200,000	200,000	200,000	200,000
Total SAGD SCO	bbl/d	1,000,000	1,000,000	1,000,000	1,000,000
Total SCO Production	bbl/d	2,800,000	2,800,000	2,800,000	2,800,000
CBP	bbl/d	1,500,000	1,500,000	1,500,000	1,500,000
Energy Costs					
Power	MM $/yr	537	1,040	1,041	1,057
Process Steam	MM $/yr	5,009	5,009	5,009	5,009
Hot Water	MM $/yr	1,180	1,180	1,180	1,180
SAGD steam	MM $/yr	8,296	8,296	8,296	8,296
Hydrogen	MM $/yr	5,650	5,584	5,584	5,584
Process fuel (NG)	MM $/yr	571	571	571	571
Diesel	MM $/yr	1,736	1,736	1,736	1,736
CO_2 Transport	MM $/yr	–	502	502	502
CO_2 Storage	MM $/yr	–	478	478	478
Total Energy Cost	MM $/yr	22,979	24,396	24,397	24,413
Unit costs					
SAGD SCO	$/bbl	19.44	20.81	20.81	20.82
Mined SCO	$/bbl	15.75	17.07	17.07	17.09
SAGD Bitumen	$/bbl	9.15	9.23	9.23	9.24

expected to be sold directly as commercial crude bitumen instead of SCO. Moreover, the crude bitumen produced via mining contains significant amounts of water and solids. Thus, the current energy model considers that the bitumen obtained from mining will be upgraded to SCO before its commercialization as indicated in the literature.[34] Following Table 7, PSI_1 is one of the least favored SCO producers since its SCO conversion is lower than the conversion considered for PSI_2. Therefore, the production capacity of this producer remains at its minimum value. Likewise, PSI_3 is also one of the least favored producers because it considers the lowest conversion among the SAGD SCO producers and it employs thermocracking (R_3) as an upgrading technology.

According to McColl et al.[54] the greenhouse gas (GHG) emissions are expected to rise to 130 million tonnes of CO_2 equivalent by 2030 if carbon capture technologies are not included in the oil sands operations. The GHG emissions obtained by the energy model are in the order of 132 million tonnes of CO_2 equivalent which is in reasonable agreement with the report.[54] Therefore, the energy model presented in this work accurately models the expected GHG emissions for the oil sands industry. Water management reduces the amount of fresh water required to maintain the oil sands operations, i.e., most of the water used by this industry is recycled water. Accordingly, the results show that the freshwater consumption constraint is not active at the solution point for the updated case studies 2030. This is because the amount of steam (S), hot water (HW) and SAGD steam (ES_{BE}) required for the oil sands operation can be satisfied using recycling water from other processes and a volume of freshwater that is below the maximum amount of freshwater that is allowed to be withdrawn from the Athabasca River. For example, for this scenario, 12% of the maximum allowed freshwater withdrawal is needed to satisfy the steam, hot water and SAGD steam demands for the oil sands operations. As shown in Table 7, SAGD steam represents one third of the annual energy operation cost. SAGD steam is the main commodity used for *in situ* extraction for both commercial bitumen and SCO production. Therefore, high costs associated with SAGD steam generation are expected for this scenario. Hydrogen represents the second highest commodity cost since hydrocracking upgrading routes (R_1-R_2) are involved in the production of over 75% of the total SCO. The hydrogen plants selected in this scenario are coal gasification plants without CO_2 capture (HG_3). These types of plants cogenerate electricity that is used as part of the oil sands electricity supply. The only power plant selected by the optimization model is a nuclear plant (E_{11}). Although the initial capital cost involved in building a nuclear plant facility is considerably high, the operating and maintenance costs of these units are lower than those required by the other types of power plants. Also, the lifetime of nuclear plants is considerably large; thus, their initial investment cost can be amortized over long periods of time. These factors position nuclear plants as a promising source of power for the oil sands operations. Therefore, this results support the addition of nuclear power plants to this energy optimization model since they have a significant effect on the energy producers' infrastructure for the future operation of the oil sands industry.

Updated case 2-2030: Scenario with CO_2 constraints

In order to analyze the effect of a CO_2 emission target on the energy producers' infrastructure, this scenario solved the updated case 1–2030 under an environmental constraint. At present, no explicit CO_2 capture targets have been set for the oil sands operations for year 2030. Hence, this scenario was solved assuming that the CO_2 emission constraint equals the expected GHG emission for 2020,[54] i.e., 70 million tonnes of CO_2 equivalent. This value represents 53% of the total

Table 8. Energy Commodity Producers' Infrastructure for the Updated Case 2030

Energy Producers	Scenario w/o CO_2 emission constraint		Scenario with CO_2 emission constraint		Scenario with CO_2 emission constraint & Nuclear penalty (both $RAF = 20$ & 385)	
	Units	Capacity	Units	Capacity	Units	Capacity
Nuclear Plant EPR-1600 (E_{11})	1	1,146,700 kW	2	868,040 kW	2	868,040 kW
Gasification w/o CO_2 capture (HG_3)	16	26.05 tonne/h 63,643.75 kW	1	21.49 tonne/h 52,497.87 kW	1	21.49 tonne/h 52,497.87 Kw
Gasification with co-capture (HG_5)	–	–	15	26.36 tonne/h 28,753.33 kW	15	26.36 tonne/h 28,753.33 kW
NG process steam boiler (B)	53	274.82 tonne/h	53	274.82 tonne/h	53	274.82 tonne/h
NG SAGD steam boiler (BE)	119	337.80 tonne/h	119	337.80 tonne/h	119	337.80 tonne/h

GHG emissions expected for the oil sands operation for 2030.[54]

Tables 7 and 8 show the SCO producer's distribution and the energy producer's configuration obtained for the updated case 2030 with and without an environmental constraint, respectively. As shown in Table 7, the distribution of the SCO producers selected by the energy model in this scenario is the same obtained in the previous scenario (without CO_2 constraint). This is because the environmental constraint only affects the selection in the energy commodity producers. Thus, the optimization model focuses on selecting an energy producers' configuration that minimizes the total energy costs and meets the CO_2 emission constraint target specified for this scenario. Following Table 7, the total annual energy cost increased by 6.17% when compared to the case of no CO_2 constraint considered in the calculations. Similarly, the power costs were significantly increased when the CO_2 constraint was considered in the formulation (almost 100%, see Table 7). This is because the cocapture hydrogen plants (HG_5) selected by the energy model consume more electricity, and, therefore cogenerate less electricity than those selected in the previous scenario (HG_3). Also, an additional supply of electricity is required to cover the compression power demands to transport the captured CO_2 via pipeline to its underground sequestration site. Therefore, more electricity must be produced independently by power plants. To accommodate these electricity demands, two nuclear power plants (E_{11}) are selected for this scenario (see Table 8). Thus, an additional nuclear power plant to that required in the previous scenario is needed to meet the CO_2 emission target. This result shows that nuclear power plants are environmental friendly electricity producers that will play a key role in the future operation of the oil sands. Most of the hydrogen demands are covered by coal gasification plants with cocapture (see Table 3, HG_5). As shown in Table 8, the distribution of boilers remained unchanged because the process steam and hot water are only available via natural gas fired boilers (B). Although SAGD steam can be produced either by boilers (BE) or small-scale nuclear energy facilities (NFE), the SAGD boilers (BE) were selected because the current costs of the nuclear facilities considered in this model are significantly high. The current lack of technological developments in small scale nuclear plants is the main reason for these plants to be costly.[54] However, the recent interest in this type of technology to generate steam will motivate the development of efficient and economically attractive small scale nuclear reactors in the near future. CO_2 transportation costs (T_c), and underground sequestrations costs (ST_c), are generated due to the CO_2 captured in hydrogen plants (HG_5).

Based on the aforementioned, the results show that the CO_2 emission target considered in this scenario can be met at the expense of a reasonably high economic penalty, i.e., a 1,417 MM \$ increase in the total energy cost. Currently, environmental legislations have been proposed for the implementation of a CO_2 cap-and-trade system in North America.[1] This system will force the industrial facilities to maintain their emissions to the atmosphere under specific levels. The facilities that may operate under their designated emission level could use the remaining allowable air emission as a tax credit that can be sold to other companies. However, those companies that generate more than the allowed capacity will be facing economic penalties. Thus, a comprehensive sensitivity analysis on the CO_2 emission will be useful to determine the influence of GHG emission reduction in the oil sands operations taking into account the proposed environmental legislations. This will allow oil sands operators to estimate their expected GHG emissions in the upcoming future and determine the compliance with the emission target levels according to environmental regulations. Analyses on the type of energy and oil producers that maintain the oil operations within a CO_2 emission constraint will be useful to plan and schedule the technologies that will be mostly used by this industry in the future. Moreover, the financial burden associated with decreasing CO_2 emission using carbon capture and storage system or complying with the economic penalties can be assessed.

Updated Case 3-2030: Scenario with CO_2 constraints and nuclear external penalty costs

A key aspect in the use of nuclear energy for power generation is related to the social, political and environmental impacts associated with the installation and operation of a nuclear power plant. Thus, the goal for this scenario is to account for the environmental CO_2 emission constraint and a penalty cost factor that accounts for environmental and social implications of a nuclear accident. To account for the latter, the RAF factor, which represents an individual-risk perception parameter in Eq. 1, was defined as an input value different than zero. The RAF factor was obtained from the literature[26] according to a hypothetical reference French nuclear accident scenario reported in a previous study.[64] In the case of a nuclear accident; individuals experienced both, a high probability of no loss and a very small probability of great loss.[26] To account for both aspects, this case study considers two individual-risk perception parameters (RAF): a baseline value of 20 and a maximum value of 385, which are indicators of high probability of no loss and a very small probability of great loss, respectively.[26] Similarly, the total cost of the nuclear accident *CNA* was set to 20,388 MM $ and the probability of occurrence of the nuclear accident *PNA* was set to 1e-6 (per reactor per year) according to information reported for the hypothetical reference French nuclear accident scenario.[26] The remaining inputs to the energy optimization model were the same to that used in the updated case 2-2030, e.g., the CO_2 emission target remained unchanged on 70 million tonnes of CO_2 equivalent/year and the oil and energy commodity producers were the same used in the previous scenario (see Tables 1 and 3).

Table 7 shows the results obtained for this scenario. As shown in this Table, the distribution of SCO production of the oil producers remain unchanged with respect to the updated case 2-2030. Similarly, Table 8 shows that the energy producers' infrastructure also remained unchanged with respect to the previous scenario. In addition, the CO_2 target emission was met at the optimal solution for this scenario. On the other hand, the power production costs increased by $ 1 million and $17 million when the *RAF* factor was set to 20 and 385, respectively. When *RAF* was set to 20, the power production costs increased represent 0.1% and 4.1e-3% of the total power costs and the total energy cost reported by the model. Likewise, the power production costs increased by 1.6% and 7.0e-2% of the total power cost, and the total energy cost when *RAF* was set to 385, respectively. These results show the penalty factors considered for this scenario do not represent a significant financial burden to the operation given the assumed low probability associated with the occurrence of a nuclear accident (1e-6/reactor/yr). Therefore, the consideration of an economic penalty associated with the environmental and social aspects of using nuclear energy does not modify the optimal configuration of oil and energy commodity producers for this CO_2 constraint scenario. However, these results were obtained based on a hypothetical French nuclear accident scenario.[64] At present, information regarding a hypothetical Canadian nuclear accident scenario is not currently available. Thus, the results presented in this work will be updated when data associated with a hypothetical nuclear accident scenario is assessed based on Canadian native factors, .i.e., local and regional population, economic activities that could be affected and possible economic losses by the industrial sector due to this hypothetical nuclear accident.

Conclusions

A comprehensive integrated energy model that includes nuclear power and water management has been developed to describe the Canadian oil sands operations in the upcoming years. This energy optimization model selects the most suitable combination of SCO and commodity producers' configuration that minimizes the annual operating energy costs of the oil sands industry. The proposed energy model was validated using information reported in a previous study for the 2030 projected operations. Results showed that this integrated approach returns energy producers and energy commodities configurations that are more economically attractive than those reported in a previous study. The proposed energy model was also used to determine the 2030 oil sands operations using recent estimates in the SCO and crude bitumen productions. Nuclear plants and water management were explicitly included in the calculations. The results show that the SCO producers that involve hydrocracking in their upgrading routes (R_1-R_2) are more likely to be selected. Hydrogen can be produced via coal gasification plants (HG_3-HG_5), which use coal as feedstock (cheap fuel) and additionally cogenerate electricity. These characteristics make coal gasification plants energy efficient and economically attractive.

Moreover, PSS_1 and PSI_2 are the most suitable SCO producers because they use energy more efficiently and their SCO conversion rates are considered high. PSS_1 can be considered as the leading SCO producer in the future because it includes an integrated mining/upgrading producer which is an economically attractive extraction method. Furthermore, the total annual energy cost increased by 6.7% when a CO_2 emission target was considered in the energy model's formulation. This result shows the economic penalty that needs to be considered to reduce the CO_2 emissions. Also, when an individual-risk perception factor was included to account for the social and environmental external costs of nuclear power for the CO_2 constraint scenarios, the associated economic penalty was not significant compared to the magnitude of the total annual energy production cost. The results provided in this work demonstrate that this energy optimization model can be used as a tool to study future production scenarios for the oil sands operations, i.e., energy commodity costs, CO_2 capture costs, and GHG emissions for a specific year. Moreover, the model can also be employed for planning and scheduling of the future configuration of the oil producers and the commodity producers in the Canadian oil sands.

This energy model considers that the model parameters are known *a priori*, i.e., a deterministic model. A more realistic approach may consider the addition of uncertainty in those model parameters that have a direct effect on the oil sands operation, e.g., natural gas price, coal price, CO_2 emission level, steam to oil ratio (*SOR*). For example a more realistic scenario for the oil sands operation considers the definition of the natural gas price (F_{NG}) as a parameter that follows a user-defined probability distribution, e.g., a normal probability distribution with specific mean and standard deviation values. Accordingly, the proposed energy deterministic model will be transformed into a stochastic energy model. The resulting stochastic model will be useful because it will determine the most likely configurations that are expected for the oil sands operation given probability distributions for the key input parameters, e.g., natural gas price. Accordingly, the operators will have more tools to plan and schedule their future activities and evaluate financial risks. Accordingly, the authors are currently working in the development of a stochastic model that describes the operations of the oil sand industry. Additionally, alternative renewable energy sources such as wind, solar and biomass for energy commodity production in the oil sands will be considered in future works.

Literature Cited

1. Energy Alberta. Oil Sands. Government of Alberta. Available at: http://www.energy.alberta.ca. Accessed May, 2011.
2. US Energy Information Administration. Country Analysis Briefs: Canada. United States Government, April 2011. Available at: http://www.eia.gov/EMEU/cabs/Canada/pdf.pdf. Accessed June, 2011.
3. International Energy Agency. World Energy Outlook 2002. Paris, IEA, 2002.

4. US Energy Information Agency. Annual Energy Outlook 2003 with Projections to 2025. US Department of Energy, Washington, DC; 2003.
5. The Oil Sands Developers Group. Oil Sands Project List. Energy from Athabasca. Alberta, Canada, January 2011. Available at: http://www.oilsandsdevelopers.ca. Accessed May, 2011.
6. McColl D, Mei M, Honarvar A, Kralovic P, Kumar C. *Green Bitumen: The Role of Nuclear, Gasification, and CCS in Alberta's Oil Sands*. Canadian Energy Research Institute. Calgary, Canada; March 2008.
7. Atomic Energy of Canada Limited (AECL). Government of Canada. Available at: http://www.aecl.ca/NewsRoom/News/Press-2007/070827.htm. Accessed on May 2011.
8. Allen E.Process water treatment in Canada's oil sands industry: I. Target pollutants and treatment objectives. *J Environ Eng Sci*. 2008;7:123–138.
9. Canadian Association of Petroleum Producers. Environment and Community: Tailings Ponds. Available at: http://www.capp.ca. Accessed June, 2011.
10. Ventosa M, Baillo A, Ramos A, Rivier M.Electricity market modeling trends. *Energy Policy*. 2005;33:897–913.
11. Gross G, Finlay DJ. Optimal bidding strategies in competitive electricity markets. *Proceedings of the 12th PSCC Conference*. Dresden, Germany, Aug. 19–23, 1996, pp. 815–823.
12. Rajamaran R, Kirsch L, Alvarado F, Clark C. Optimal self-commitment under uncertainty energy and reserve prices. In: Hobbs BF, Rothkopf MH, O'Neill RP, Chao HP, eds. *The Next Generation of Electric Power Unit Commitment Models*. International Series in Operations Research & Management Science. Boston, MS: Kluwer Academic Publishers; pp. 93–116, 2001.
13. Ordorica-Garcia G, Elkamel A, Douglas PL, Croiset E, Gupta M.Modeling the Energy Demands and Greenhouse Gas Emissions of the Canadian Oil Sands Industry. *Energy Fuels*. 2007;21:2098–2111.
14. Ordorica-Garcia G, Elkamel A, Douglas PL, Croiset E, Gupta M.Energy optimization model with CO_2 emission constraints for the Canadian oil sands industry. *Energy Fuels*. 2008;22:2660–2670.
15. Finan A, Kadak A.Integration of nuclear energy into oil sands projects. *J Eng Gas Turbines Power*. 2010;132/042902–1.
16. Energy Alberta. Report on nuclear power and alberta. Calgary, Alberta, 2009. Available at: http://www.energy.alberta.ca/Electricity/pdfs/NuclearPowerReport.pdf. Accessed May, 2011.
17. Ordorica-Garcia G, Elkamel A, Douglas PL, Croiset E. Optimal implementation of CO_2 capture technology in power and hydrogen production for Oil Sands operations. *Can J Chem Eng*. 2010;88: 881–888.
18. The Pembina Institute. Available at: http://www.pembina.org. Accessed May, 2011.
19. Government of Canada. *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*. Minister of Environment. Canada; March, 2008.
20. Environment Canada. Available at: http://www.ec.gc.ca.
21. The Canadian Chamber of Commerce. *A Carbon Tax vs. Cap-and-Trade. Policy Brief, Economic Policy Series*. Ottawa, ON, Canada; December, 2008.
22. Thomas S. *The economics of nuclear power: analysis of recent studies*. Public Services International Research Unit, University of Greenwich, Greenwich, UK; July 2005.
23. Ordorica-Garcia G, Douglas P, Croiset E, Zheng L.Technoeconomic evaluation of IGCC power plants for CO_2 avoidance. *Energy Convers Manage*. 2006;47:2250.
24. Rubin ES, Rao AB, Chen C. Comparative assessments of fossil fuel power plants with CO_2 capture and storage. *Proceedings of the GHGT-7 Conference*. Vancouver, Canada; September 2004.
25. Davison J.Performance and costs of power plants with capture and storage of CO_2. *Energy*. 2007;32:7.
26. Eeckhoudt L, Schieber C, Schneider T.Risk aversion and the external cost of a nuclear accident. *J Environ Manage*. 2000;58:109–117.
27. Margulies TS.Risk optimization: sitting of nuclear power electricity generating units. *Reliability Eng Syst Safety*. 2004;38:323–325.
28. Cowing MM, Pate-Cornell ME, Glynn PW.Dynamic modeling of the tradeoff between productivity and safety in critical engineering systems. *Reliability Eng Syst Safety*. 2004;86:269–284.
29. Simbeck D, Chang E. Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis. Report NREL/SR-540–32525: National Renewable Energy Laboratory, Golden, CO; 2002.
30. Simbeck DR. Hydrogen costs with CO_2 capture. *Proceedings of the GHGT-7 Conference*. Vancouver, Canada; September 2004.
31. Chiesa P, Consonni S, Kreutz T, Williams R.Co-production of hydrogen, electricity, and CO_2 from coal with commercially ready technology. Part A: Performance and emissions. *Int Hydrogen Energy*. 2005;30:747.
32. Kreutz T, Williams R, Consonni S, Chiesa P.Co-production of hydrogen, electricity, and CO_2 from coal with commercially ready technology. Part B: Economic analysis. *Int J Hydrogen Energy*. 2005;30:769.
33. Harrel, G. Steam System Survey Guide. Report ORNL/TM-2001/263. Oak Ridge National Laboratory, TN; 2002.
34. Athabasca Oil Sands Corp (AOSC). Corporate Overview: Technology. Calgary, Alberta, Canada. Available at: http://www.aosc.com/corporate-overview/technology.html. Accessed July, 2011.
35. Industry Canada. Oil Sands Technology Roadmap: Upgrading in a Dynamic Market. Ottawa, Ontario, Canada. Available at: http://www.ic.gc.ca/eic/site/ic1.nsf/eng/h_00014.html. Accessed September, 2011.
36. OPTI Canada Long Lake Project Application for Commercial Approval; OPTI Canada: Calgary, Canada, 2002, Volume 1, Section A, B, and C. Application submitted to the Alberta Energy Utilities and Board.
37. Alberta Oil Sands Annual Statistics for 2003; Report ST 2003–43. Alberta Energy and Utilities Board: Calgary, Canada; 2004.
38. Sunderland B. Hydrogen Production, Recovery and Use at Syncrude. *Presented at the EFI Conference on Technologies to Enable the Hydrogen Economy*. Tucson, AZ, April 2001:22–24.
39. Schumacher M. *Heavy Oil and Tar Sands Recovery and Upgrading International Technology*. Noyes Data Corp: Park Ridge, NJ; 1982.
40. Van Driesen R, Caspers J, Campbell AR, Lunin G.LC-fining upgrades heavy crudes. *Hydrocarbon Proc*. 1979;58:5.
41. Meyers RA. *Handbook of Synfuels technology*. New York, NY: McGraw-Hill, Inc; 1984.
42. Spath P, Mann M. *Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming*. National Renewable Energy Laboratory: Golden, CO; February 2001.
43. Yui S, Chung K. H.Processing oil sands bitumen is Syncrude's R&D Focus. *Oil Gas J*. 2001;99:17.
44. *Refining Process Handbook*. http://www.hydrocarbonprocessing.com/. Accessed 2004.
45. Alberta Environment.*Draft interim framework*: In: *Stream Flow Needs and Water Management System for Specific Reaches of the Lower Athabasca River*. Alberta Environment. Edmonton, Canada; 2006.
46. Alberta Environment. Athabasca River Water Management Framework: Alberta's Regulatory Backstop to Protect the Athabasca River. Government of Alberta. Available at: http://www.environment.alberta.ca/documents/Athabasca_RWMF_Highlights.pdf. Accessed September, 2011.
47. General Algebraic Modeling System (GAMS).GAMS Development Corp.,Washington, DC. http:/www.gams.com. Accessed September, 2011.
48. Torres FE.Linearization of mixed-integer products. *Math Program*. 1991;49:427–428.
49. Oral M, Kettani O.A Linearization procedure for quadratic and cubic mixed-integer problems. *Operations Res Soc Am*. 1992;40:109–116.
50. General Algebraic Modeling System (GAMS) Home Page. Available at: http:/www.gams.com/dd/docs/solvers/dicopt.pdf. Accessed on September 2011.
51. Kocis GR, Grossman IE.Relaxation strategy for the structural optimization of process flow sheets. *Ind Eng Chem Res*. 1987;26:1869–1880.
52. Lastusilta T, Bussieck MR, Westerlund T. *Comparison of Some High-Performance MINLP Solvers*. Process Design Laboratory, Åbo Akademi University, Finland and GAMS Software GmbH, Germany; 2007.
53. Duran MA, Grossman IE.An outer-approximation algorithm for a class of mixed-integer nonlinear programs. *Math Program*. 1986;36:307–339.
54. McColl DC, Mei M, Millington D, Slagorsky M. *Canadian Oil Sands Supply Costs and Development Projects (2009-2043)*. Canadian Energy Research Institute: Calgary, Canada. November 2009. Study No. 121, ISBN 1–896091-93–8.
55. Government of Alberta. Facts about Alberta's oil sands and its industry. Oil Sands Discovery Centre: Alberta, Canada, July 2011.
56. National Energy Board. Canada's Oil Sands: Opportunities and Challenges to 2015. An Energy Market Assessment. National Energy Board: Calgary, Canada; May 2004.

57. National Energy Board. Canada's Oil Sands: Opportunities and Challenges to 2015: An Update. An Energy Market Assessment. National Energy Board: Calgary, Canada, June 2006.
58. US Energy Information Administration. Available at: http://www.eia.doe.gov/oiaf/aeo/pdf/trend_5.pdf. Accessed June, 2011.
59. New Technology Magazine. Available at: http://www.newtechmagazine.com. Accessed May, 2011.
60. Nexen, Inc. Available at: http://www.nexeninc.com. Accessed May, 2011.
61. Shell Canada. Available at: http://www.shell.ca. Accessed on May 2011.
62. Energy Alberta. Available at: http://www.energy.alberta.ca. Accessed May, 2011.
63. Government of Canada. Oil Sands Technology Roadmap: Upgrading in a Dynamic Market Industry. Ontario, Canada. Available at: http://www.ic.gc.ca. Accessed June, 2011.
64. Dreicer M, Tort V, Manen P. Estimation of Physical Impacts and Monetary Valuation of Priority Pathways, Nuclear Fuel Cycle. CEPN Report R-234; 1995.

Manuscript received July 27, 2011, revision received Oct. 5, 2011, and final revision received Jan. 10, 2012.