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Energy Optimization Model with CO_2-Emission Constraints for the Canadian Oil Sands Industry

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In this paper, a model for optimizing energy production for oil sands operations is presented. The objective of the model is to minimize the total annual cost of supplying energy to the oil sands industry, subject to CO_2 emissions constraints. The energy is supplied in the form of power, hydrogen, steam, hot water, diesel, and process fuel. The model, which is named the energy optimization model (EOM), is conceived as an analytical and planning tool for the energy industry and government sectors. The EOM determines optimal combinations of power and hydrogen plants that satisfy given energy demands of oil sands operations, at minimal cost and with reduced CO_2 emissions. The EOM thus generates optimal energy infrastructures and quantifies the costs and emissions associated with energy production for bitumen and upgraded bitumen production. A case study is used to showcase the capabilities of the model and illustrate its applicability as a tool to develop and evaluate optimal CO_2 mitigation strategies in the oil sands industry. The case study consists of optimizing the historical energy demands of oil sands operations in the year 2003, with added CO_2 emissions constraints. The EOM results for the case study include the energy costs and emissions associated with SCO (synthetic crude oil) and bitumen production at increasing CO_2 reduction levels. Optimal energy infrastructures for each CO_2 reduction level are determined by the EOM. The model quantifies the cost increases because of CO_2-constrained energy production on a per-barrel-of-oil basis as well as the maximum attainable CO_2 emissions reductions for the featured case study. A discussion of the usefulness of the model as a technology screening tool for specific energy production scenarios is provided.

Introduction

The oil sands, located primarily in the province Alberta, in Western Canada, are a strategic energy asset that has experienced unprecedented growth in the past decade. High oil prices, combined with concerns over foreign oil supply in North America, have combined to boost the development of this resource. The combined production of bitumen and bitumen-derived synthetic crude oil (SCO) is forecasted to reach 2.8 million barrels a day by 2015.[1]

Bitumen extraction and upgrading processes, as currently executed in the Athabasca region in Alberta, are highly energy-intensive operations, requiring as much as 2 GJ/bbl of SCO.[2] This energy is presently generated from fossil fuels, generating significant CO_2 emissions. The combined emissions from bitumen extraction and upgrading make the oil sands industry the single largest contributor to greenhouse gas (GHG) emissions growth in Canada.[3]

Developing sustainable growth strategies for the oil sands industry requires that operations be not only economically attractive but also environmentally acceptable. Sustainable development in this industry requires energy self-sufficiency, decreased water and GHG emissions, as well as addressing various social and technological issues. Currently, the provincial government has implemented a number of policies to help achieve the above objectives. Most notably, Alberta is the first jurisdiction in North America to mandate GHG emissions intensity reductions for large industrial facilities.[4] On the other hand, industry, government, and research agencies have conducted a variety of studies to evaluate options for CO_2 emissions mitigation, mainly using carbon capture and storage (CCS) technology.[5,6]

The challenge for Canada is also a great opportunity to develop world-class expertise on GHG mitigation technology by integrating novel energy production technologies with CCS on a large scale within the oil sands industry. The geology of the province favors capturing CO_2 generated by energy production processes and using it in enhanced oil recovery (EOR),

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(1) National Energy Board. Canada's Energy Future. Reference Case and Scenarios to 2030; National Energy Board Publications Office: Calgary, Canada, 2007.

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(5) The ecoENERGY Carbon Capture and Storage Task Force. Canada's Fossil Energy Future: The Way Forward on Carbon Capture and Storage. Report to the Minister of Alberta Energy and the Minister of Natural Resources Canada; Alberta, Canada, 2008.

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enhanced coal bed methane (ECBM), or storing it in underground formations.[7,8]

The motivation for this work is based on the following five key facts: (1) The sustained growth of the oil sands industry in Alberta is poised to drive the energy demands in the region to unprecedented levels. (2) Most of this energy will likely have to come from fossil fuels, which exist locally and are customarily used in oil sands operations. (3) In a CO_2-constrained world, the emissions of the oil sands industry must be reduced. Otherwise, financial/environmental penalties are likely to result. (4) CCS technology, when coupled to energy production, offers a viable way to mitigate emissions from oil sands operations. (5) The province of Alberta has an ideal geology for underground CO_2 storage and use in value-added operations, such as EOR and ECBM.

Although the above issues are reasonably well-understood individually, a clear, comprehensive approach to integrate the advantages offered by each one is currently lacking. Although the notion of using "clean" energy production technology to reduce GHG emissions is clear, a strategic way to apply it in the context of the oil sands industry is less so. Further, the uncertainty surrounding future environmental legislation, fuel supply and prices, and future bitumen and SCO production levels add to the complexity of an already formidable challenge.

What is required, thus, is an optimal mechanism to apply the current knowledge of CCS and energy production technologies with an emphasis on oil sands operations in Alberta under the assumption of a CO_2-constrained environment to achieve meaningful emissions reductions. This paper proposes that the above can be accomplished using a process systems engineering approach, making extensive use of process modeling and optimization of the oil sands operations. Ultimately, this project investigates the relationships between bitumen extraction and upgrading processes, their energy requirements, CO_2 emissions and emissions abatement, and the costs associated with energy production and CO_2 abatement.

Within the above context, this project involves minimizing the costs of supplying all of the energy required for oil sands operations, subject to given CO_2 emission reductions targets. To do so, we have developed a mixed integer linear programming (MILP) model on the GAMS[9] platform. This model, which is designated the energy optimization model (EOM), addresses the following problem statement: What is the optimal combination of energy production technologies, feedstocks, and CO_2 capture processes to use in the oil sands industry that will satisfy energy demands at minimal cost while meeting CO_2 reduction targets for given bitumen/SCO production levels?

The goal of the EOM is to minimize the overall cost of producing H_2, steam, hot water, and power for the oil sands industry, while reducing total CO_2 emissions by a given percentage. This is accomplished by selecting the types and number of power and H_2 plants and steam producers that optimally satisfy demands for the above commodities in the oil sands industry.

This paper presents the MILP model, describes its features, and demonstrates its capabilities by optimizing the historical energy demands of the oil sands industry in 2003. These demands are calculated using the OSOM model,[10] a stand-alone mathematical model that quantifies the demands for electricity, hydrogen, steam, hot water, natural gas, and diesel fuel of the oil sands industry as a function of SCO and bitumen production, based on current energy-production technologies.

EOM Superstructure

The superstructure of the optimization model is shown in Figure 1. Oil sands producers are shown on the right side (energy-demand side) according to product and extraction technology. The products included in the model are bitumen and SCO, whereas the extraction technologies are mining and steam-assisted gravity drainage (SAGD). Fleet wide hot water (W), hydrogen (H), process and SAGD steam (S/SS), power (P), and diesel (D) demands are represented by circles in Figure 1. The energy demands are met by three plant types, represented as boxes on the left (energy-supply side) in Figure 1: (a) boilers, (b) hydrogen plants, and (c) power plants. These energy producers consume natural gas (X) or coal (Y). A third feedstock (Z) is also shown in the superstructure, to denote the potential ability of some plants in the model to use alternative fuels, such as petroleum coke or other bitumen residues. It is anticipated that future versions of the EOM will include these alternative feedstocks. In this study, however, only natural gas and coal are available as fuels for all of the energy-producing plants.

The CO_2 emissions in the superstructure are represented by E, whereas CO_2 captured in power and hydrogen plants is symbolized by CCO2. The oil products in the superstructure are mined SCO (MSCO), SAGD SCO (TSCO), and bitumen (BIT). The energy-demand side in Figure 1 also shows optional power (PEX) and hydrogen (HEX) demands, which, in this study, have a default value of zero. Oil sands producers A1−A3, B1−B3, and C, as defined in Table 1, appear on the demand side. The production values for producers A1−A3 are computed by the OSOM based on the oil sands processed in the year 2003.[10,11] The production figures for plants B1−B3 are null because in 2003 no SAGD plants with integrated bitumen upgrading existed. The values for producers C come from ref 12.

The EOM selects the type and number of hydrogen plants, power plants, and boilers from a pool of available technologies with and without integrated CO_2 capture. The particular combination of plants determined by the EOM for given production levels of SCO and bitumen *and* CO_2 reduction target is referred to as an *optimal energy infrastructure* in this work.

It is important to notice that the EOM does not calculate the energy demands to be optimized. These values are inputs to the model and must be specified by the user. In this work, the energy demands of the oil sands industry in 2003 are calculated using the OSOM. The OSOM is a deterministic model that was specifically developed as a source of inputs for the EOM model.[2,10] This model computes energy demands of oil sands operations based on the oil production of individual producers. Table 2 summarizes the energy demands as calculated by the OSOM, arranged by commodity.

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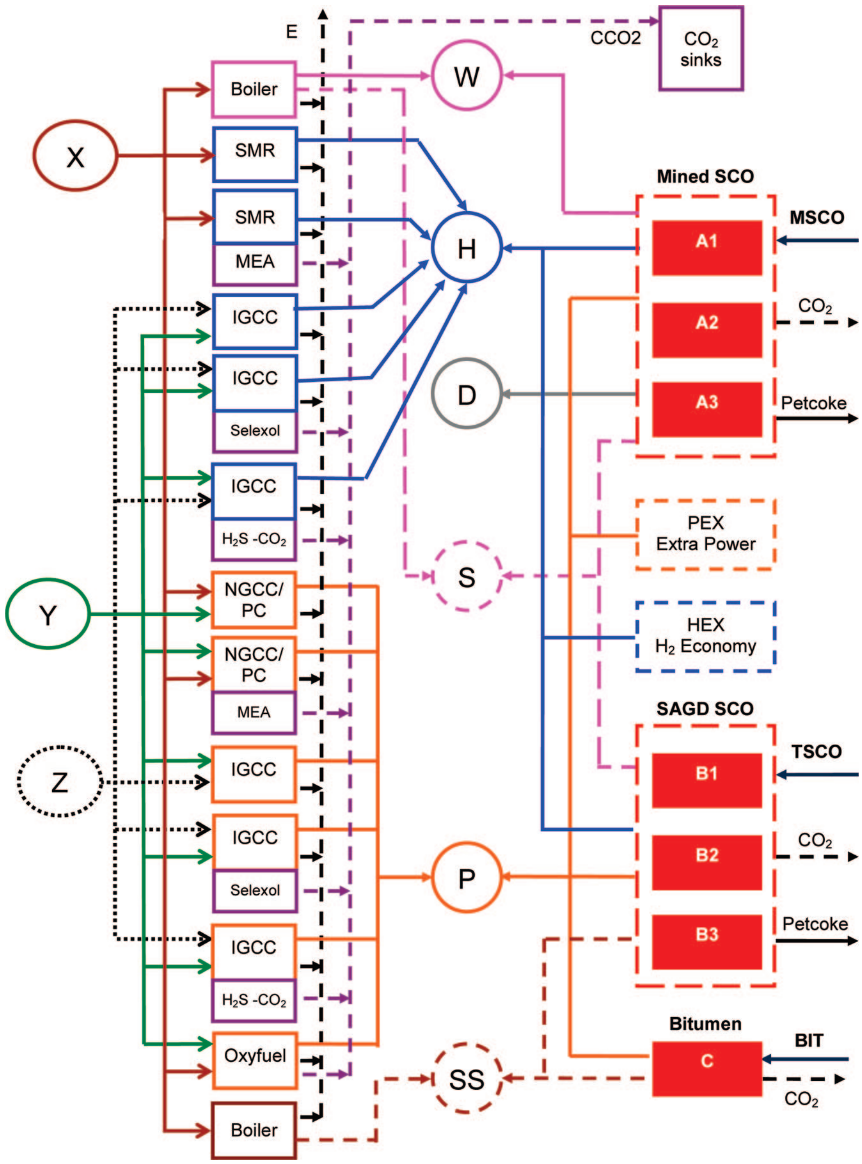

Figure 1. EOM superstructure.

Table 1. Production Values from 2003 for All EOM Producers (bbl/day)[10]

producer	description[a]	daily production
A1	mined bitumen upgraded by LCF + FC + HT	231 000
A2	mined bitumen upgraded by DC + HT	213 000
A3	mined bitumen upgraded by LCF + HT	94 000
A	total mined SCO production	538 000
B1	SAGD bitumen upgraded by LCF + FC + HT	0
B2	SAGD bitumen upgraded by DC + HT	0
B3	SAGD bitumen upgraded by LCF + HT	0
B	total SAGD SCO production	0
C	total SAGD-diluted bitumen production	350 000

[a] DC, delayed coking; FC, fluid coking; HT, hydrotreating; LCF, LC fining.

Table 2. Energy Demands for Oil Sands Operations[2]

energy demands	units	A1	A2	A3	C
diesel	L/h	18 950	18 954	5582	N/A
hot water	tons/h	12 460	12 362	3640	N/A
steam, process	tons/h	1539	1166	383	N/A
steam, SAGD	tons/h	N/A	N/A	N/A	5642
power	kW	232 845	249 235	106 933	49 632
hydrogen	tons/h	29.5	24.5	17.8	N/A
process fuel	GJ/h	119	995	197	N/A

Because the energy demands are inputs to the EOM, the model has great flexibility to optimize different energy production scenarios. The user could, for instance, specify all energy demands to be zero, with the exception of power, which would be useful to provide optimal infrastructures to meet the electricity demands of a city, state, or country, with reduced CO_2 emissions. The EOM is thus conceived as a flexible energy production and optimization analysis tool, which is currently applied to the oil sands industry.

EOM Technologies and Plant Sets

Aside from conventional natural gas-fired boilers, several different power and hydrogen production technologies are available in the optimization model. A list of all such technologies in the form of plant sets is presented below. The default number of units per set is shown in parentheses. The default number of plants per set corresponds roughly to 4 times the oil sands industry energy demands in 2003. If larger energy outputs are to be optimized, the number of units in the pertinent sets must be increased.

Table 3. Sources of Techno-economic Data for EOM Technologies

plant set	boiler	hydrogen plant	power plant
S_BS_{SB}	13–15		
$S_{H_1}S_{H_2}$		16 and 17	
$S_{H_3}S_{H_4}S_{H_5}$		18 and 19	
$S_{P_1}S_{P_2}S_{P_6}S_{P_7}$			20
$S_{P_3}S_{P_4}S_{P_5}$			21 and 22
$S_{P_8}S_{P_9}$			23

Boilers

S_B = natural gas-fired boilers producing process steam and hot water (default number = 90)

S_{SB} = natural gas-fired boilers producing SAGD steam (default number = 150)

Hydrogen Plants

S_{H1} = steam methane reforming (SMR) hydrogen plants without CO_2 capture (default number = 120)

S_{H2} = SMR hydrogen plants with 90% CO_2 capture via MEA (default number = 120)

S_{H3} = coal gasification hydrogen plants without CO_2 capture (default number = 30)

S_{H4} = coal gasification hydrogen plants with 90% CO_2 capture via Selexol (default number = 30)

S_{H5} = coal gasification H_2 plants with 90% CO_2 plus H_2S co-capture via Selexol (default number = 30)

Power Plants

S_{P1} = NGCC power plants without CO_2 capture (default number = 30)

S_{P2} = PC (supercritical) power plants without CO_2 capture (default number = 30)

S_{P3} = IGCC power plants without CO_2 capture (default number = 30)

S_{P4} = IGCC power plants with 88% CO_2 capture via Selexol (default number = 30)

S_{P5} = IGCC power plants with 88% CO_2 plus H_2S co-capture via Selexol (default number = 30)

S_{P6} = NGCC power plants with 90% CO_2 capture via MEA (default number = 30)

S_{P7} = PC (supercritical) power plants with 90% CO_2 capture via MEA (default number = 30)

S_{P8} = natural gas Oxyfuel power plants with CO_2 capture (default number = 30)

S_{P9} = coal Oxyfuel power plants with CO_2 capture (default number = 30)

The EOM incorporates comprehensive techno-economic parameters for each of the above technologies, which are used to estimate the costs of building and operating the optimal energy infrastructures and the associated CO_2 emissions. Table 3 lists the studies that are the source for techno-economic data for each of the technologies featured in the EOM.

Indexes

In the EOM, the following indexes are linked to model variables and plant sets: b, boiler; C, coal; D, demand; NG, natural gas; h, hydrogen plant; p, power plant; PF, process fuel.

Thus, HHV_{NG} is used in this work to denote the high heating value of natural gas, whereas $X_b\ \forall\ b \in S_B$ is the natural gas consumption in the set of boilers S_B.

Constraints

The core of the optimization model consists of a series of constraints relating the input parameters to process variables of interest (e.g., steam, coal consumption, CO_2 emissions). These constraints include also mass and energy balances that link the energy supply side to the specified energy demands. The balances featured in this section are organized according to variables.

Process Steam. Steam at 6300 kPa and 500 °C (as used by Syncrude) is produced in natural-gas-fired boilers S_B. A portion of the boiler capacity is used for hot water (35 °C) production (see the Hot Water section below). Additional steam from SMR plants might also be available; thus, the total process steam supply in the fleet is given by

$$S = \sum_{b \in S_B} S_b + \sum_{h \in S_{H_1}} S_h \geq S_D \qquad (1)$$

The above constraint specifies that the total process steam supply must be equal or greater than the fleet-wide demand. The amount of steam produced in the boilers is given by eq 2

$$S_b = \frac{HHV_{NG}PSP\eta_{B_b}}{\Delta HS} X_b\ \forall\ b \in S_B \qquad (2)$$

HHV_{NG} is the heating value of natural gas. PSP is the percentage of the capacity of the boiler dedicated to steam production. The thermal efficiency of the boiler is represented by η_B, and ΔHS is the enthalpy of steam. The (optional) steam produced in SMR plants is calculated as follows:

$$S_h = SSR{\cdot}H_h\ \forall\ h \in S_{H_1} \qquad (3)$$

SSR is a parameter that relates the amount of steam produced in hydrogen plants to the hydrogen output of the plant. By default, the value of SSR in the optimizer is zero, and thus, the steam output of SMR plants is also zero. The entirety of the steam in the EOM by default comes from boilers. This is the case for all of the results presented in this paper.

SAGD Steam. Steam at 8000 kPa is used for SAGD bitumen extraction. The steam is produced in natural-gas-fired boilers S_{SB}. The total SAGD steam production in the fleet is given by eq 4

$$SS = \sum_{b \in S_{SB}} SS_b \geq SS_D \qquad (4)$$

The above constraint specifies that the total SAGD steam supply must be equal or greater than the fleet-wide demand. The amount of SAGD steam produced in the boilers is given by eq 5

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$$\mathrm{SS_b} = \frac{\mathrm{HHV_{NG}}\eta_{\mathrm{B_b}}}{\Delta\mathrm{HS}} X_\mathrm{b}\ \forall\ \mathrm{b} \in S_{\mathrm{SB}} \quad (5)$$

Hot Water. In the EOM, all hot water is produced in S_B boilers. The relationship between hot water supply and demand is given by the following equation:

$$W = \sum_{\mathrm{b} \in S_\mathrm{B}} W_\mathrm{b} \geq W_\mathrm{D} \quad (6)$$

The hot water produced in the NG boilers is defined by eq 7

$$W_\mathrm{b} = \frac{\mathrm{HHV_{NG}}(1 - \mathrm{PSP})\eta_{\mathrm{B_b}}}{\Delta\mathrm{HW}} X_\mathrm{b}\ \forall\ \mathrm{b} \in S_\mathrm{B} \quad (7)$$

where ΔHW is the enthalpy of the hot water leaving the boilers. The water is assumed to have a temperature of 35 °C, as specified in ref 14.

Hydrogen. Hydrogen, which is used for bitumen upgrading, is produced in steam-reforming- and IGCC-based plants, as shown below. A certain excess amount of hydrogen may be produced (HHE), which represents the hydrogen available for export. This hydrogen could be used for mobile applications or in secondary energy generation processes outside of oil sands operations. By default HHE is zero.

$$H = \sum_{\mathrm{h} \in S_{\mathrm{H_1}} \cup S_{\mathrm{H_2}}} H_\mathrm{h} + \sum_{\mathrm{h} \in \bigcup_{i=3}^{5} S_{\mathrm{H}_i}} H_\mathrm{h} \geq H_\mathrm{D} + \mathrm{HHE} \quad (8)$$

The hydrogen produced in natural-gas-based plants is given by the following equation:

$$H_\mathrm{h} = \frac{\mathrm{HHV_{NG}}}{N_{\mathrm{H_h}}} X_\mathrm{h}\ \forall\ \mathrm{h} \in S_{\mathrm{H_1}} \cup S_{\mathrm{H_2}} \quad (9)$$

where N_H is the energy required to produce a ton of hydrogen. The hydrogen produced in gasification plants using coal as feedstock is given by eq 10

$$H_\mathrm{h} = \frac{\mathrm{HHV_C}}{N_{\mathrm{H_h}}} Y_\mathrm{h}\ \forall\ \mathrm{h} \in \bigcup_{i=3}^{5} S_{\mathrm{H}_i} \quad (10)$$

Power. The total power produced in the fleet is the sum of power produced in all power plants plus the power cogenerated in gasification hydrogen plants as shown in eq 11 below

$$P = \sum_{\mathrm{p} \in \bigcup_{i=1}^{9} S_{\mathrm{P}_i}} P_\mathrm{p} + \sum_{\mathrm{h} \in \bigcup_{i=3}^{5} S_{\mathrm{H}_i}} P_\mathrm{h} \geq P_\mathrm{D} + \mathrm{PEX} + \sum_{\mathrm{h} \in \bigcup_{i=1}^{2} S_{\mathrm{H}_i}} P_\mathrm{h} + P_{\mathrm{CO_2}} \quad (11)$$

PEX is the power for export generated in the fleet (optional). By default, this value is zero in the optimizer. P_h represents both the power co-generated in gasification hydrogen plants (left of ≥ in eq 11) and the ancillary power requirements of SMR hydrogen plants (right of ≥ in eq 11). P_{CO_2} is the power required to transport the captured CO_2 to storage, as given by eq 12. PCT is a parameter representing the unitary power requirements for CO_2 transport (per 100 km segment), and PKM is the length of the pipeline. PCT values were provided by staff at the Alberta Research Council's Carbon and Energy Management Unit, from their in-house model for CO_2 transport.[24]

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(23) Davison, J. Performance and costs of power plants with capture and storage of CO_2. *Energy* **2007**, *32*, 7.

(24) Faltinson, J. Personal communication, Carbon and Energy Management, Alberta Research Council, Feb 2007.

$$P_{\mathrm{CO_2}} = \left(\sum_{\mathrm{h} \in \bigcup_{i=2}^{5} S_{\mathrm{H}_i}} C_h + \sum_{\mathrm{p} \in \bigcup_{i=1}^{9} S_{\mathrm{P}_i}} C_p \right) \mathrm{PCT} \frac{\mathrm{PKM}}{100} \quad (12)$$

The individual plant electricity generation is given by the following expressions:

$$P_\mathrm{p} = \frac{\mathrm{HHV_{NG}}}{\mathrm{HRP_p}} X_\mathrm{p}\ \forall\ \mathrm{p} \in S_{\mathrm{P_1}} \cup S_{\mathrm{P_6}} \cup S_{\mathrm{P_8}} \quad (13)$$

$$P_\mathrm{p} = \frac{\mathrm{HHV_C}}{\mathrm{HRP_p}} Y_\mathrm{p}\ \forall\ \mathrm{p} \in \bigcup_{i=2}^{5} S_{\mathrm{P}_i} \cup S_{\mathrm{P_7}} \cup S_{\mathrm{P_9}} \quad (14)$$

HRP symbolizes the heat rate of each power plant. Equations 13 and 14 represent the power produced in natural gas and coal power plants, respectively. Equation 15 is used to calculate both the ancillary energy requirements of SMR hydrogen plants and co-produced power from gasification plants. HPW is a parameter that represents the amount of power required/co-generated as a function of the hydrogen output of each plant.

$$P_\mathrm{h} = \mathrm{HPW_h} H_\mathrm{h}\ \forall\ \mathrm{h} \in \bigcup_{i=1}^{5} S_{\mathrm{H}_i} \quad (15)$$

Natural Gas. Natural gas is consumed in boilers, hydrogen plants, and power plants. It is also used as process fuel for upgrading operations. Accordingly, the following equation is developed:

$$X = \sum_{\mathrm{b} \in S_\mathrm{B} \cup S_{\mathrm{SB}}} X_\mathrm{b} + \sum_{\mathrm{h} \in S_{\mathrm{H_1}} \cup S_{\mathrm{H_2}}} X_\mathrm{h} + \sum_{\mathrm{p} \in S_{\mathrm{P_1}} \cup S_{\mathrm{P_6}} \cup S_{\mathrm{P_8}}} X_\mathrm{p} + X_{\mathrm{PF}} \quad (16)$$

The optimization will adjust each one of the variables in eq 16 as needed, to satisfy energy demands in the fleet and CO_2 reduction constraints. Currently, there is no constraint on the total amount of natural gas available for operations nor on the units that can use natural gas as fuel. This in practical terms implies that the natural gas supply in the EOM is unlimited. Further, the price of gas does not change as its demand increases. These restrictions can be easily waived by including bounds on natural gas availability and having a gas price function in terms of demand.

Coal. Coal is consumed in hydrogen and power plants and is also available as process fuel for upgrading operations according to eq 17

$$Y = \sum_{\mathrm{h} \in \bigcup_{i=3}^{5} S_{\mathrm{H}_i}} Y_\mathrm{h} + \sum_{\mathrm{p} \in \bigcup_{i=2}^{5} S_{\mathrm{P}_i} \cup S_{\mathrm{P_7}} \cup S_{\mathrm{P_9}}} Y_\mathrm{p} + Y_{\mathrm{PF}} \quad (17)$$

The amount of coal consumed in each plant is a function of its output, as determined by the EOM. As with natural gas, no supply constraint is imposed on coal and its price does not vary with increased demand. This restriction can also be waived as for the case of natural gas.

CO_2. All plants included in the upgrading process consume fossil fuels, producing CO_2 as a byproduct. The total CO_2 is the sum of CO_2 emitted and CO_2 captured, as shown in eq 18.

$$\mathrm{CO_2} = \mathrm{E} + \mathrm{C} \quad (18)$$

The total CO_2 emitted comes from boilers and hydrogen and power plants as shown below. The terms of eq 19 correspond to boilers, NG and coal H_2 plants, and natural gas and coal power plants in that order. The last two terms in eq 19 correspond to the CO_2 emissions from diesel and process fuel use in mining oil sands and upgrading bitumen to SCO, respectively.

$$E = \sum_{b \in S_B} E_b + \sum_{b \in S_{SB}} E_b + \sum_{h \in S_{H_1} \cup S_{H_2}} E_h + \sum_{h \in \bigcup_{i=3}^{5} S_{H_i}} E_h + \sum_{p \in S_{P_1} \cup S_{P_6} \cup S_{P_8}} E_p + \sum_{p \in \bigcup_{i=2}^{5} S_{P_i} \cup S_{P_7} \cup S_{P_9}} E_p + E_{DF} + E_{PF} \quad (19)$$

The total CO_2 captured in the fleet is given by eq 20

$$C = \sum_{h \in S_{H_2}} C_h + \sum_{h \in S_{H_4} \cup S_{H_5}} C_h + \sum_{h \in S_{P_6} \cup S_{P_8}} C_p + \sum_{p \in S_{P_4} \cup S_{P5} \cup S_{P_7} \cup S_{P9}} C_p \quad (20)$$

The terms of eq 20 represent the CO_2 captured from NG and coal hydrogen plants and natural gas and coal power plants in that specific order. In the optimization model, no CO_2 captured is applied to steam boilers (S_B and S_{SB}).

The total CO_2 emissions reduction is given by eq 21. The CO_2 emissions of the fleet must be equal or less than a user-defined reduction percentage, ERG, multiplied by the baseline emissions, as shown in eq 22. EBL represents the baseline CO_2 emissions of the base case, which is an input to the optimization model. In this study, this figure is determined by running the optimization model using only natural gas as fuel, no CO_2 capture, and employing exclusively SMR and NGCC plants for hydrogen and power production, respectively. When using this approach, the baseline emissions and costs for any production level are equivalent to a “business as usual” (BAU) scenario. If another baseline scenario is desired, alternative feedstock(s), capture level, and technologies must be employed. The corresponding total CO_2 emissions value is then used as a new EBL with the desired set of conditions to be compared against the baseline case.

$$\mathrm{RED} = \mathrm{EBL} - \mathrm{E} \quad (21)$$

$$\mathrm{E} \le \mathrm{EBL}(1 - \mathrm{ERG}) \quad (22)$$

The emissions from boilers are given by eq 23. The CO_2 emitted by hydrogen plants and power plants is given in eqs 24 and 25, respectively.

$$E_b = \mathrm{FEF}_{NG} X_b \;\forall\, b \in S_B \cup S_{SB} \quad (23)$$

$$E_h = \mathrm{HEF}_h H_h \;\forall\, h \in \bigcup_{i=1}^{5} S_{H_i} \quad (24)$$

$$E_p = \mathrm{EFP}_p P_p \;\forall\, p \in \bigcup_{i=1}^{9} S_{P_i} \quad (25)$$

Parameters FEF, HEF, and EFP are the CO_2 emissions per unit of natural gas burned, hydrogen produced, and power generated, respectively. The CO_2 emissions resulting from diesel fuel and process fuel are given by eqs 26 and 27.

$$E_{DF} = \mathrm{FEF}_{DIE} D_D \quad (26)$$

$$E_{PF} = (\mathrm{FEF}_{NG} X_{PF}) + (\mathrm{FEF}_C Y_{PF}(\mathrm{ULC} - \mathrm{ASH})) \quad (27)$$

where FEF represents the CO_2 emissions per unit of natural gas, diesel, and C in the coal. The last term in eq 27 adjusts the CO_2 emissions from coal burning by subtracting the mass of the coal that is ash (ASH) and, thus, non-CO_2 forming. ULC is the carbon content of the fuel as given in the ultimate analysis.

The CO_2 captured in hydrogen plants is a function of their output (eq 28). Likewise, for power plants, the CO_2 captured is calculated depending upon the power output of each particular plant, as seen in eq 29. CCH and CCP are parameters that relate the CO_2 captured to the unitary output of the power and hydrogen plants and are calculated on the basis of the techno-economic performance of each technology.

$$C_h = \mathrm{CCH}_h H_h \;\forall\, h \in S_{H_2} \cup S_{H_4} \cup S_{H_5} \quad (28)$$

$$C_p = \mathrm{CCP}_p P_p \;\forall\, p \in \bigcup_{i=4}^{9} S_{P_i} \quad (29)$$

In the EOM, a number of binary variables are defined to quantify the number of units and plants present in the optimal energy infrastructures as well as to establish constraints.

Boilers
$\mathrm{IB}_b = 1$, if boiler b exists in the infrastructure; 0, otherwise; $b \in S_B \cup S_{SB}$

Hydrogen Plants
$\mathrm{IH}_h = 1$, if plant h exists in the infrastructure; 0, otherwise; $h \in \cup_{i=1}^{5} S_{H_i}$

Power Plants
$\mathrm{IP}_p = 1$, if plant p exists in the infrastructure; 0, otherwise; $p \in \cup_{i=1}^{9} S_{P_i}$

Energy Producers. This set of constraints limits the number of boilers, H_2, and power plants that can exist at any given time in the optimization. Individual technologies can be excluded from the optimization by setting its number of plants to zero. Conversely, one may choose to specify a limited number of a certain type of plants, or when a constraint associated with a certain technology is deactivated, one may allow for an unlimited number of such plants to exist.

Equations 30–32 show the general form of the constraints on the number of boilers, hydrogen, and power plants allowed in the optimizer, respectively.

$$\sum \mathrm{IB}_b \le \text{integer} \quad \forall\, b \in S_B \cup S_{SB} \quad (30)$$

$$\sum \mathrm{IH}_h \le \text{integer} \quad \forall\, h \in \bigcup_{i=1}^{5} S_{H_i} \quad (31)$$

$$\sum \mathrm{IP}_p \le \text{integer} \quad \forall\, p \in \bigcup_{i=1}^{9} S_{P_i} \quad (32)$$

The integer numbers above should be set to be equal to or less than the number of units specified for individual plant sets (see the EOM Technologies and Plant Sets section earlier).

Energy Supply. This set of constraints ensures that the total of each energy commodity produced in boilers, hydrogen, and power plants in the optimizer meets the demands specified by the user. The reader must note that most of these constraints have been defined earlier, hence their numbering is shown based on their initial order of appearance in the paper.

$$\sum_{b \in S_B} S_b + \sum_{h \in S_{H_1}} S_h \ge S_D \quad (33)$$

$$\sum_{b \in S_{SB}} \mathrm{SS}_b \ge \mathrm{SS}_D \quad (34)$$

Equations 33 and 34 are the supply constraints on process and SAGD steam, respectively. Equation 35 shows the constraints on hot water production, while eqs 36 and 37 regulate the hydrogen and power production in the fleet, respectively. Equation 38 ensures that the demands for process fuel are met by either coal or natural gas or a combination of both.

$$\sum_{b \in S_B} W_b \ge W_D \quad (35)$$

$$\sum_{h \in S_{H_1} \cup S_{H_2}} H_h + \sum_{h \in \bigcup_{i=3}^{5} S_{H_i}} H_h \ge H_D + \mathrm{HHE} \quad (36)$$

$$\sum_{p \in \bigcup_{i=1}^{9} S_{P_i}} P_p + \sum_{h \in \bigcup_{i=3}^{5} S_{H_i}} P_h \geq P_D + \mathrm{PEX} + \sum_{h \in \bigcup_{i=1}^{2} S_{H_i}} P_h + P_{CO_2} \quad (37)$$

$$(X_{PF}\mathrm{HHV}_{NG}) + (Y_{PF} \cdot 1000 \cdot \mathrm{HHV}_C) = \mathrm{PF}_D\mathrm{HHV}_{NG} \quad (38)$$

Base Case Energy. Some additional constraints can also be introduced to allow for the fixing of the outputs of a subset of power and hydrogen plants to match the energy demands in 2003, the base case year in this study. This may be desirable when optimizing the energy demands of the oil sands industry in a post-2003 time period if some plants from 2003 are still operational. These "base case energy supply" constraints are inactive by default in our current GAMS implementation of the model but can be activated for any given run.

Equations 39–41 define the base case energy supply for power, hydrogen plants, and process fuel, respectively. In 2003, all power is assumed to be generated in NGCC plants and the hydrogen is produced in SMR plants, both without CO_2 capture. Likewise, all process fuel is assumed to be natural gas. The base case energy constraints therefore are based on these technologies, as seen below.

$$\sum P_p \geq P_D^{2003}\ \forall\, p \in S_{P_1} \quad (39)$$

$$\sum H_h \geq H_D^{2003}\ \forall\, h \in S_{H_1} \quad (40)$$

$$X_{PF} \geq \mathrm{PF}_D^{2003} \quad (41)$$

Unit Capacity. In addition to constraints on the energy supply of the fleet, an additional set of constraints is specified to ensure that the individual output of each energy producer in the infrastructure does not exceed its design capacity.

Equations 42–44 are the capacity constraints for boilers. SBC is the nominal capacity of each boiler in the fleet.

$$S_b \leq (\mathrm{SBC} \cdot \mathrm{PSP})\mathrm{IB}_b \quad \forall\, b \in S_B \quad (42)$$

$$S_b \leq \mathrm{SBC} \cdot \mathrm{IB}_b \quad \forall\, b \in S_{SB} \quad (43)$$

$$W_b \leq \mathrm{SBC}(1 - \mathrm{PSP})\left(\frac{\Delta \mathrm{HS}}{\Delta \mathrm{HW}}\right)\mathrm{IB}_b \quad \forall\, b \in S_B \quad (44)$$

The capacity constraints for individual hydrogen plants are given by the product of their design output (HCAP) and their specified availability factor (CF), as shown below.

$$H_h \leq \mathrm{HCAP}_h\mathrm{CF}_h\mathrm{IH}_h \quad \forall\, h \in \bigcup_{i=1}^{5} S_{H_i} \quad (45)$$

Similar to hydrogen plants, the capacity constraints for individual power plants are given by the product of their nominal output (POUT) and their specified availability factor (CF), as shown in eq 46.

$$P_p \leq \mathrm{POUT}_p\mathrm{CF}_p\mathrm{IP}_p \quad \forall\, p \in \bigcup_{i=1}^{9} S_{P_i} \quad (46)$$

CO_2 Reduction. A constraint is imposed on the allowed CO_2 emissions of the fleet of producers. It reduces the total emissions by a specified percentage, with respect to the baseline emissions for a given year. Equation 47 illustrates the CO_2 reduction constraint, which was introduced earlier (see the CO_2 section above).

$$\mathrm{E} \leq \mathrm{EBL}(1 - \mathrm{ERG}) \quad (47)$$

Objective Function

The goal of the optimization is to minimize the total yearly cost of supplying all of the energy required to sustain a given production level of SCO and bitumen in the oil sands industry. Accordingly, the objective function is defined as the annual costs of producing steam, hot water, hydrogen, and power plus the cost of supplying diesel and process fuel to the oil sands industry. In addition to these energy commodities, the model also accounts for the cost of transporting CO_2 to the sinks via pipeline and for CO_2 storage/injection costs. Equation 48 expresses the objective function in a general form.

$$\text{minimize}[P_{cost} + H_{cost} + S_{cost} + \mathrm{SS}_{cost} + W_{cost} + F_{cost} + D_{cost} + \mathrm{CT}_{cost} + \mathrm{CS}_{cost}] \quad (48)$$

Each term in eq 48 comprises the capital, nonfuel operating, and fuel costs, where applicable. Equations 49 and 50 show the breakdown of the above costs in the EOM for power and H_2 plants, in that order.

$$P_{cost} = \sum_{p \in \bigcup_{i=1}^{9} S_{P_i}} \left[\mathrm{IP}_p(\mathrm{CAP}_p + \mathrm{OM}_p) + t\left(P_p \frac{\mathrm{HRP}_p}{1000}\mathrm{fuel}_{cost}\right)\right] \quad (49)$$

$$H_{cost} = \sum_{h \in \bigcup_{i=1}^{5} S_{H_i}} \left[\mathrm{IH}_h(\mathrm{CAP}_h + \mathrm{OM}_h) + t\left(\frac{\mathrm{fuel}_{cost}}{1000}(X_h\mathrm{HHV}_{NG} + Y_h\mathrm{HHV}_C)\right)\right] \quad (50)$$

where CAP and OM are the fixed annual capital and nonfuel operating costs, respectively. These costs are calculated separately, using supporting equations as presented in ref 2. The parameter t denotes the assumed hours per year for the economic analysis.

The costs of steam and hot water production consist only of the cost of water and fuel as show in eqs 51–53. This simplification stems from the fact that the capital expense of a boiler, when amortized over 20+ years is negligible, in comparison to the annual operating (chiefly fuel) costs for steam generation.

$$S_{cost} = \sum_{b \in S_B} t\left[\left(X_b\mathrm{PSP}\frac{\mathrm{HHV}_{NG}}{1000}\mathrm{NG}_{cost}\right) + (S_b\mathrm{water}_{cost})\right] \quad (51)$$

$$\mathrm{SS}_{cost} = \sum_{b \in S_{SB}} t\left[\left(X_b\frac{\mathrm{HHV}_{NG}}{1000}\mathrm{NG}_{cost}\right) + (S_b\mathrm{water}_{cost})\right] \quad (52)$$

$$W_{cost} = \sum_{b \in S_B} t\left[\left(X_b(1 - \mathrm{PSP})\frac{\mathrm{HHV}_{NG}}{1000}\mathrm{NG}_{cost}\right) + (W_b\mathrm{water}_{cost})\right] \quad (53)$$

The costs of process fuel and diesel fuel are specified by eqs 54 and 55.

$$F_{cost} = t\left[\left(X_{PF}\frac{\mathrm{HHV}_{NG}}{1000}\mathrm{NG}_{cost}\right) + (Y_{PF}\mathrm{HHV}_C\mathrm{coal}_{cost})\right] \quad (54)$$

$$D_{cost} = t \cdot D_D \cdot \mathrm{diesel}_{cost} \quad (55)$$

Finally, the CO_2 transport costs as a function of distance and storage/injection costs are given by eqs 56 and 57. The default pipeline length in the case study considered in the next section is 600 km, which covers CO_2 transport from Fort McMurray to a theoretical hub in Edmonton (400 km) and from Edmonton to nearby depleted oil fields (200 km radius), such as the Red Water Field.[8]

$$\mathrm{CT}_{cost} = t\left(\sum_{h \in \bigcup_{i=2}^{5} S_{H_i}} C_h + \sum_{p \in \bigcup_{i=1}^{9} S_{P_i}} C_p\right)\mathrm{CCT}\frac{\mathrm{PKM}}{100} \quad (56)$$

$$\mathrm{CS}_{\mathrm{cost}} = t\left(\sum_{h \in \bigcup_{i=2}^{5} S_{H_i}} C_h + \sum_{p \in \bigcup_{i=1}^{9} S_{P_i}} C_p\right)\mathrm{CST} \qquad (57)$$

The parameters CCT and CST are the unitary CO_2 transport cost per 100 km pipeline segment and the unitary CO_2 injection/storage cost, respectively. PKM represents the length of the pipeline (in kilometers). The total CO_2 transport and storage costs are a function of the CO_2 captured and the length of the pipeline. The default value of CST is taken from ref 25.

Baseline Costs and Emissions

A good way to test the performance of the EOM is by using it to optimize a well-known problem. For this study, the OSOM base case[10] constitutes an ideal case study. Because the base case results are readily available and well-understood, we decided to optimize the historical energy demands of the oil sands industry in 2003, under CO_2 reduction targets. This approach is useful to evaluate the features and output of the EOM. Furthermore, optimizing the 2003 case is an interesting exercise that can shed light on potential CO_2 mitigation strategies, derived from the model results.

Before optimizing energy demands, the EOM is used to calculate the baseline costs and emissions of the energy required to produce SAGD bitumen and mined SCO in the year 2003. This is accomplished by deactivating all power and hydrogen plants in the model, except for NGCC and SMR plants without capture. Hence, the assumed energy production infrastructure (non-optimal) corresponding to the year 2003 is specified, and its economics are assessed.

The costs calculated by the EOM are a function of a fair number of economic and technical parameters. The most representative economic parameters and their corresponding values for the 2003 case study are shown in Table 4.

One key purpose of the EOM is to assess the economic and environmental impacts of various energy production technologies and feedstocks in the oil sands industry. Therefore, the unitary energy costs in \$/bbl and the CO_2 intensities in tons of CO_2/bbl are used to measure the said impacts. This allows for consistent comparison among multiple scenarios.

The baseline (nonoptimal) energy costs calculated by the EOM for the year 2003 are \$13.64/bbl and \$5.38/bbl for SCO and SAGD bitumen, respectively. The total annual energy costs for all producers are 3.36 billion dollars, including energy plant capital charges, fuel, and nonfuel operating expenses. In terms of emissions, the baseline CO_2 emissions of the oil sands industry in 2003 are 2249 tons CO_2/h. Thus, the baseline intensities of SCO and bitumen are 0.075 and 0.037 tons of CO_2/bbl, respectively. The above values correspond to unconstrained CO_2 emissions in the oil sands industry.

It is useful to remark that the above costs are not the operating costs associated with SCO and bitumen production. They are rather the energy portion of the operating costs. Hence, items such as non-energy-producing assets (e.g., mining, upgrading equipment, etc.), overburden removal, and land reclamation are not covered in the costs presented above. Only energy-related capital and operating costs are contemplated in the EOM, for all product and oil sands producer combinations.

The EOM provides the breakdown of the energy costs, as shown in a graphical form in Figure 2, for all products, as a function of the energy infrastructure and feedstocks. The EOM output reveals that, for the 2003 non-optimized case, hydrogen, steam, and hot water production account for over three-quarters of the cost of producing a barrel of SCO, while for SAGD bitumen, the bulk of the energy costs is due to steam generation. These trends are consistent with the results from a previous study[10] that revealed similar distributions for the unitary energy demands of SCO and bitumen.

(25) Mitchell, B.; Van Ham, J. Canada's CO_2 Capture and Storage Technology Roadmap; CANMET Energy Technology Centre: Ottawa, Canada, 2006.

Table 4. Key Economic Parameters for EOM Analysis for Year 2003[2]

parameter	units	value
coal cost	\$/GJ	1.9
natural gas cost	\$/GJ	6.0
diesel cost	\$/L	0.7
CO_2 transport cost (600 km)	\$ (ton of CO_2)$^{-1}$ (100 km)$^{-1}$	1.2
CO_2 storage cost	\$/ton of CO_2	6

Optimization Results under CO_2 Constraints

In the following analysis, the above demands are optimized at increasing CO_2 reduction targets, starting with a 0% reduction with respect to the baseline (no CO_2 capture, natural gas only fuel). It is expected that the attainable CO_2 reduction has a maximum finite value. The EOM is able to find that value, for a given combination of inputs.

Table 5 summarizes the results of the optimization. Table 6 shows the optimal energy infrastructures determined by the EOM for increasing CO_2 reduction targets. The first row in Table 5 contains the baseline values for 2003, which correspond to the energy costs and emissions of a nonoptimized energy infrastructure, found on the first row in Table 6. The second row in Table 5 shows the EOM results for an optimal energy infrastructure with identical CO_2 emissions as the baseline case. Such an optimized energy infrastructure could potentially reduce the energy costs of SCO by 8% while emitting the same amount of CO_2 as the baseline given the specified coal and natural gas prices. Columns 3 and 4 in Table 5 show the relative difference of the energy costs of SCO with respect to baseline and optimal values, respectively, with a 0% CO_2 emissions reduction. Thus, for instance, the baseline energy costs of SCO are 7.6% higher than the optimized baseline case. Conversely, the SCO energy costs of the optimized baseline case are 7.1% lower than those of the non-optimal baseline.

After an optimal baseline case was found by the EOM, the CO_2 reduction level was increased, as can be seen in Table 5. Optimal solutions were found for CO_2 reduction values of 10−30%. The optimizer yielded an infeasible solution for a CO_2 reduction level of 40%. Therefore, a value of 35% was specified, which yielded an optimal solution. The maximum possible CO_2 reduction attainable for this case study was found to be 35.2%. No combination of plants in the model can yield CO_2 reductions greater than the above value, which corresponds to an infrastructure consisting of NG Oxyfuel power plants and SMR plants with CO_2 capture via MEA scrubbing, as seen in Table 6.

The results from the EOM suggest that CO_2 reductions up to 30% with respect to the baseline can be achieved with modest SCO energy costs savings. CO_2 reductions greater than 30% are possible, with 35.2% being the maximum possible reduction. Table 5 reveals that SCO CO_2 intensity reductions ranging from 12 to 45% are possible using optimal energy infrastructures in this case study. However, the above reductions roughly result in a 20% increase in the energy cost of SCO (with respect to baseline costs) or 30% with respect to optimal baseline values.

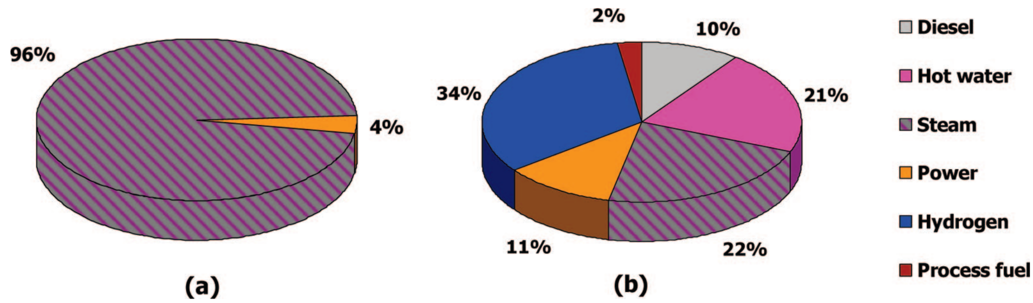

Figure 2. Energy costs breakdown from 2003 by commodity for (a) bitumen and (b) SCO.

Table 5. Optimal Energy Costs and Associated CO_2 Emissions for Year 2003

	SCO					bitumen			
CO_2 reduction	cost ($/bbl)	cost (baseline) ± (%)	cost (optimal) ± (%)	CO_2 intensity (tons/bbl)	CO_2 intensity ± (%)	cost	CO_2 intensity (tons/bbl)	CO_2emissions (tons/h)	CO_2captured (tons/h)
0, baseline	13.64	0.0	7.6	0.075	0.0	5.38	0.037	2249	0
0, optimal	12.67	−7.1	0.0	0.075	0.0	5.34	0.038	2249	886
10%	12.91	−5.3	1.9	0.066	−12.2	5.35	0.037	2024	886
20%	13.18	−3.3	4.0	0.056	−26.2	5.37	0.038	1799	1,239
30%	13.45	−1.4	6.2	0.046	−38.3	5.40	0.036	1575	1,390
35%	16.32	19.7	28.8	0.042	−44.7	5.47	0.036	1462	1,093
35.2%	16.60	21.7	31.0	0.041	−45.0	5.50	0.036	1458	997

Table 6. Optimal Energy Infrastructures as a Function of CO_2 Reduction for Year 2003[a]

CO_2 reduction	S_{P_1}	S_{P_2}	S_{P_3}	S_{P_4}	S_{P_6}	S_{P_7}	S_{P_8}	S_{P_9}	S_{H_1}	S_{H_2}	S_{H_3}	S_{H_4}
0, baseline	2								13			
0, optimal	1	1									1	2
10%	2										1	2
20%	1	1										3
30%	1				1							3
35%							2			11		1
35.2%	1						2			13		

[a] S_{P_1}, NGCC; S_{P_2}, PC; S_{P_3}, IGCC; S_{P_4}, IGCC with CO_2 capture; S_{P_6}, NGCC with CO_2 capture; S_{P_7}, PC with CO_2 capture; S_{P_8}, NG Oxyfuel; S_{P_9}, coal Oxyfuel; S_{H_1}, SMR; S_{H_2}, SMR with CO_2 capture; S_{H_3}, H_2 IGCC; S_{H_4}, H_2 IGCC with CO_2 capture.

The energy cost and CO_2 intensity of bitumen are mostly insensitive to changes in the energy infrastructures. This is explained by the fact that over 95% of the energy cost per bbl of bitumen is due to steam production. Therefore, the economic impact of variations in the cost of power on the former cost is very low. Similarly, the CO_2 intensity of bitumen is to a large degree dictated by the emissions from steam production, which account for 96% of the total emissions in SAGD extraction. Therefore, even if the CO_2 intensity of the power produced is dramatically reduced, the final impact on the bitumen CO_2 intensity is almost negligible.

In addition to providing energy costs and CO_2 emissions and emissions intensities, the EOM results are useful for assessing the applicability of individual technologies for a particular scenario. For instance, Table 6 suggests that, at CO_2 reduction levels under 20%, NGCC and PC plants without capture are favored over IGCC or Oxyfuel power plants. Similarly, for CO_2 reduction levels less than 30%, coal gasification is the preferred technology for hydrogen production. As CO_2 reduction levels approximate their maximum value, gas-fueled Oxyfuel and SMR plants with CO_2 capture dominate over all other technologies. Table 6 shows that some technologies are never selected in the analysis (i.e., IGCC and coal Oxyfuel power plants, etc.), which suggests an inadequate suitability, given the particular combination of fuel costs and other techno-economic parameters for the featured case study.

Energy plants that co-capture and co-inject the acid gas underground (S_{P_5} and S_{H_5}) were excluded from this case study. The transport of acid gas streams containing elevated levels of hydrogen sulfide over the distances specified in this scenario is currently deemed infeasible. The reasons are chiefly due to safety concerns and the anticipated difficulty in obtaining a permit for such a transport pipeline in Alberta. Nevertheless, CO_2 and H_2S co-capture, transport, and injection is practiced safely in Alberta over short distances and could be attractive for some oil sand operators in the future, and the EOM can easily incorporate these technologies in its analyses.

Conclusions

A MILP optimization model has been introduced in this paper. The EOM yields optimal infrastructures for energy production, given a set of techno-economic parameters and energy demands. The model minimizes the total annual costs of energy production, by selecting the optimal combination of power and hydrogen plants. The user may specify a desired CO_2 emissions reduction, which must be met by the optimal energy infrastructure, while simultaneously minimizing the costs of energy production.

The EOM is currently applied to the oil sands industry, where it is useful as an analysis, optimization, and planning tool for industry and government stakeholders. The EOM results provide insights concerning the financial and environmental impacts of using different energy production and CO_2-capture technologies as a means to achieve desired CO_2 reductions in the oil sands industry. The implementation of the optimal energy infrastructures derived from the EOM has great potential to achieve significant CO_2 emissions reductions, at the minimal (optimal) cost.

In this paper, a case study consisting of the historical energy demands of the oil sands industry in the year 2003 was presented. The EOM was used to minimize the annual costs of producing H_2 and power for oil sands operations, subject to CO_2 emissions reductions constraints. In addition, the EOM determined the total energy costs of producing SCO and bitumen, including steam and hot water production and diesel and process fuel use.

The analysis results for the 2003 case study reveal that optimal energy infrastructures determined by the EOM have the potential to reduce the energy costs of SCO production by 2−7%, while attaining CO_2 reductions of up to 30% with respect to the baseline (2003) values. Also, the optimization results show that the maximum CO_2 reduction possible for the 2003 case study is 35.2%. The financial impact of this CO_2 reduction is a net increase of 22% in the energy costs associated with SCO production and roughly 2% for bitumen production via SAGD. The environmental impact of implementing the optimal energy infrastructures is a CO_2 intensity decrease ranging from 12 to 45% for SCO. In absolute terms, the optimal energy infrastructures could potentially reduce the CO_2 emissions of the oil sands industry to 1458 tons/h from 2249 tons/h in the 2003 (historical) case study.

The results of the case study also showcase the ability of the EOM to assess the applicability of individual technologies to minimize energy production costs at varying CO_2 emissions reduction constraint levels. The EOM output reveals that different technologies dominate at various CO_2 reduction levels. For instance, power plants without capture are suitable for CO_2 reduction levels lesser than 30%, while above 30% reduction, Oxyfuel- and CO_2-enabled plants are favored.

The results of the analysis confirm that the EOM can successfully optimize energy production for oil sands operations under increasing CO_2 constraints. The model yields a unique energy infrastructure that is optimal for each scenario. When used in conjunction with the OSOM,[10] the EOM is a useful analysis tool to study energy demands and production in the oil sands industry. In a forthcoming paper, we use the OSOM model to estimate the future energy demands of the oil sands industry and the EOM to develop optimal energy infrastructures to supply the energy with reduced CO_2 emissions. The outcomes of the study aim to shed light on potential technologies and strategies to mitigate CO_2 emissions in the oil sands industry at minimal cost, by optimizing energy production using the EOM.

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Nomenclature

A1 = mined bitumen upgraded by LCF + FC + HT
A2 = mined bitumen upgraded by DC + HT
A3 = mined bitumen upgraded by LCF + HT
B1 = SAGD bitumen upgraded by LCF + FC + HT
B2 = SAGD bitumen upgraded by DC + HT
B3 = SAGD bitumen upgraded by LCF + HT
BAU = business as usual
BBL = barrels of oil
BIT = SAGD bitumen
C = SAGD-diluted bitumen
CCO2 = CO_2 captured
CCS = carbon dioxide capture and storage
DC = delayed coking
E = CO_2 emission
FC = fluid coking
GHG = greenhouse gas
HEX = additional H_2 demands in the optimization model (optional)
HT = hydrotreatment
IGCC = integrated gasification combined-cycle power plant
LCF = LC fining
MEA = monoethanolamine
MILP = mixed integer linear program
MSCO = mined SCO
NG = natural gas
NGCC = natural gas combined-cycle power plant
OSOM = oil sands operations model
PC = supercritical pulverized coal power plant
PEX = additional power demands in the optimization model (optional)
SAGD = steam-assisted gravity drainage
SB = boiler, 6300 kPa and 500 °C steam
SCFD = standard cubic feet per day
SCO = synthetic crude oil
SMR/SR = steam methane reforming hydrogen plant
SSB = boiler, 80% steam at 8000 kPa
TSCO = SAGD SCO
X = natural gas
Y = coal
Z = alternative (opportunity) fuel

Variables

AF = annual amortization factor (%)
C = CO_2 captured (tons/h)
CAP = annual capital cost of plant ($/year)
C_h = CO_2 captured in hydrogen plants (tons/h)
C_p = CO_2 captured in power plants (tons/h)
CS_{cost} = CO_2 injection/storage costs ($/year)
CT_{cost} = CO_2 transport costs ($/year)
D_D = diesel fuel demand (h^{-1})
E = CO_2 emitted (tons/h)
E_b = CO_2 emissions of boilers (tons/h)
E_{DF} = CO_2 emissions of diesel fuel (tons/h)
E_h = CO_2 emissions of hydrogen plants (tons/h)
E_p = CO_2 emissions of power plants (tons/h)
E_{PF} = CO_2 emissions of process fuel (tons/h)
H_D = hydrogen demand (tons/h)
H_h = hydrogen from H_2 plants (tons/h)
H_{OUT} = hydrogen supply (tons/h)
OM = annual nonfuel O&M cost of plant ($/year)
P = power supply (kW)
P_{CO_2} = power required for CO_2 transport (kW)
P_D = power demand (kW)
PF_D = process fuel demand (N m^3 h^{-1})
P_h = power co-produced or consumed in hydrogen plants (kW)
P_{H_2} = power for hydrogen plants (kW)
P_p = power from power plants (kW)
RED = net CO_2 reduction of the fleet (tons/h)
S = process steam supply (tons/h)
S_b = process steam from boilers (tons/h)
S_D = process steam demand (tons/h)
S_h = process steam from H_2 plants (tons/h)
SS = SAGD steam supply (tons/h)
SS_b = SAGD steam from boilers (tons/h)
SS_D = SAGD steam demand (tons/h)
W = hot water supply (tons/h)
W_b = hot water from boilers (tons/h)
W_D = hot water demand (tons/h)
X = natural gas demand (N m^3 h^{-1})
X_b = natural gas demand in boilers (N m^3 h^{-1})
X_h = natural gas demand in hydrogen plants (N m^3 h^{-1})
X_i = natural gas consumption in unit i (N m^3 h^{-1})
X_p = natural gas demand in power plants (N m^3 h^{-1})
X_{PF} = natural gas demand for process fuel (N m^3 h^{-1})
Y = coal demand (kg/h)
Y_h = coal demand in hydrogen plants (kg/h)
Y_i = coal consumption in unit i (kg/h)
Y_p = coal demand in power plants (kg/h)
Y_{PF} = coal demand for process fuel (kg/h)

Binary Variables

IB_b = 1, if boiler b exists in the fleet; 0, otherwise
IH_h = 1, if hydrogen plant h exists in the fleet; 0, otherwise
IP_p = 1, if power plant p exists in the fleet; 0, otherwise

Parameters
CCH = CO_2 captured in hydrogen plants (tons of CO_2 captured/ton of H_2)
CCP = CO_2 captured in power plants (tons of CO_2 captured/kWh)
CCT = unitary CO_2 transport costs [\$ (ton of CO_2)$^{-1}$ (100 km)$^{-1}$]
CF = plant availability (capacity) factor (%)
CST = unitary CO_2 injection/storage costs (\$/ton of CO_2)
D = diesel demands (h^{-1})
EBL = baseline CO_2 emissions for a given year [tons/h]
EFP = unitary CO_2 emissions of power plant (tons of CO_2/kWh)
ERG = target CO_2 reduction percentage (% of baseline emissions for a given year)
ERS = power requirements for SAGD bitumen extraction (kW/ton of bitumen)
f = engine diesel fuel consumption (h^{-1})
F = process fuel demands (MJ/h)
FCH = fuel consumption rate in hydrogen plant (MJ/ton of H_2)
FEF_C = fuel emissions factor of coal (tons of CO_2/ton of C in coal)
FEF_{DIE} = fuel emissions factor of diesel fuel (tons of CO_2/L)
FEF_{NG} = fuel emissions factor of natural gas (tons of CO_2 N^{-1} m^{-3})
FRD = fuel requirements of delayed coker (MJ/ton of feed)
FRL = fuel requirements of LC finer (MJ/ton of feed)
fuel cost = natural gas or coal cost (\$/GJ)
H = hydrogen demand (tons/h)
HEF = unitary CO_2 emissions of hydrogen plant (tons of CO_2/ton of H_2)
HHE = additional hydrogen production (tons/h)
HHV_C = high heating value of coal (MJ/ton)
HHV_{NG} = high heating value of natural gas (MJ N^{-1} m^{-3})
HPW = power co-production/demands in hydrogen plants (kWh/ton of H_2)
HRP = heat rate of power plant (MJ/kWh)
N_H = fuel consumption in H_2 plant (MJ/ton of H_2)
P = power demand (kW)
PCT = unitary power demands for CO_2 transport [kWh (ton of CO_2)$^{-1}$ (100 km)$^{-1}$]
PEX = excess power (kW)
PKM = CO_2 pipeline length (km)
PSP = percentage of boiler capacity used for steam production (%)
RET = annual capital charge rate (%)
S = process steam demand (tons/h)
SS = SAGD steam demand (tons/h]
SSE = steam requirements for secondary bitumen extraction (tons of steam/ton of froth)
SSR = steam produced in H_2 plant (tons/ton of H_2 produced)
t = annual hours of operation (h/year)
W = hot water demand (tons/h)
water cost = fresh water cost (\$/ton)
ΔHS = enthalpy of steam (MJ/ton)
ΔHW = enthalpy of hot water (MJ/ton)
η_B = boiler thermal efficiency (%)

Indexes
b = boiler
C = coal
D = demand
NG = natural gas
h = hydrogen plant
p = power plant
PF = process fuel

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