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Replacing Natural Gas in Alberta's Oil Sands: Trade-Offs Associated with Alternative Fossil Fuels

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Concerns regarding resource availability and price volatility have prompted industries to consider replacing natural gas (NG) with an alternative fuel. The oil sands industry utilizes large amounts of NG for the production of steam, electricity, and hydrogen, and several "replacement fuels" are currently being considered. A life cycle framework is developed and applied to two generic oil sands projects as a case study (mining with upgrading and in situ with upgrading) to examine the energy, greenhouse gas, and financial implications of replacing NG with four fossil fuels: asphaltenes, coke, bitumen, and coal. Key trade-offs are identified among the fuels, as well as those associated with applying carbon capture and storage (CCS) to the systems. The analysis indicates that there is no vector dominant alternative to NG among the fuels investigated, although asphaltenes appear to offer the most potential. The analysis confirms that CCS can reduce life cycle emissions to 25% of those of current systems but will not be implemented for oil sands energy systems without a financial incentive or regulatory requirement. Under the analysis' base conditions, the CO_2 avoidance cost is \$66/tonne CO_2 equivalent and \$87/tonne for the mining and in situ asphaltenes cases, respectively. However, the impact of compounding uncertainties is demonstrated and shown to be critical for appropriate interpretation.

1. Introduction

Concerns regarding resource availability and price volatility have prompted industries to consider replacing natural gas (NG) with an alternative fuel. Electricity generators, for example, concerned about high NG prices are investigating potential replacements.[1] NG is widely used because of its attractive properties compared to many fossil fuel alternatives (e.g., efficient production and distribution system, clean-burning, noncorrosive), including the lowest greenhouse gas (GHG) emissions per unit of energy. NG accounted for 21% of the world total primary energy supply in 2006 with the industrial sector being the largest consumer.[2] As such, replacement of NG by industry potentially has significant techno-economic and environmental implications. As North America and other jurisdictions continue to develop and implement regulations targeting abatement of GHG emissions, any entity considering replacing NG with an alternative fuel must consider the GHG emissions implications, financial considerations, and a host of other factors.

The oil sands industry in Northern Alberta, Canada, uses mining and in situ operations as the two primary means of recovering bitumen, the petroleum resource in oil sands deposits. Bitumen is a heavy, viscous form of oil found combined with sand and water. Operators utilize traditional surface mining techniques and then process the sands to extract the bitumen, or they perform the extraction in the reservoir itself (in situ) and recover bitumen to the surface (see ref 3 for more information on these processes). Steam assisted gravity drainage (SAGD) is the in situ technique currently experiencing the most growth in the industry. It involves injecting large quantities of steam into the reservoir to reduce the viscosity of the bitumen, allowing it to be pumped to the surface. Once the bitumen has been extracted from the oil sands, it can be combusted or gasified on-site as a fuel source, diluted, and sold to the market or upgraded to a light "sweet" or light "sour" synthetic crude oil (SCO). Upgrading can use a variety of techniques to convert the heavy bitumen to lighter hydrocarbons.

The oil sands industry utilizes large amounts of NG in their operations for the production of steam, electricity, and hydrogen. In 2005, these operations purchased almost 20 000 000 m^3/day of

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(1) Gaalaas, T.; Randall, C. *Coal Age* **2006**, *111* (4), 53–54.
(2) International Energy Agency. *Key World Energy Statistics*. http://www.iea.org/textbase/nppdf/free/2008/key_stats_2008.pdf, 2008.
(3) Alberta Chamber of Resources. *Oil Sands Technology Roadmap: Unlocking the Potential*; Alberta Chamber of Resources: Edmonton, Canada, 2004.

NG, a number forecast to approximately triple by 2015.[4] The industry is considering several potential "replacement fuels" for NG, including asphaltenes, coke, and bitumen (byproducts or products of oil sands operations) and coal (readily available in Alberta). These alternative feedstocks require different production processes and have varying properties (e.g., carbon content, energy density) and, therefore, have different life cycle implications. While other alternatives have been proposed that are anticipated to have lesser negative environmental impacts (e.g., geothermal, biomass), the fossil fuels are expected to be the most widely considered over the next decade due to their relatively low cost, accessibility, and system reliability.

As the finished products from the oil sands industry are primarily transportation fuels, regulations targeting transportation fuels' life cycle GHG emissions are impacting decision-making within the industry. These regulations [e.g., California's low carbon fuel standard (LCFS)] will require fuel providers to ensure that the mix of fuels they sell into the market meets, on average, a declining GHG emissions standard based on estimates of CO_2 equivalent (CO_2E) per energy unit of fuel on a life cycle basis. Under these regulations, unconventional fossil fuels such as bitumen may face particular challenges due to the energy-intensive nature of their production. Further, the implications for life cycle GHG emissions of replacing any NG must be determined, as replacement with heavier feedstocks may further impede the ability of oil sands products to meet LCFSs.

The objective of this investigation is to examine, on a life cycle basis, trade-offs among GHG emissions, energy use and financial cost associated with substituting four fossil fuels (asphaltenes, coke, bitumen, and coal) for NG. As a case study, the production of electricity, steam, and hydrogen for oil sands operations, using a gasification system, is investigated. Gasification was chosen as it offers the flexibility required to produce multiple products in varying proportions from a single system and to capture emissions such as CO_2 and criteria air contaminants relatively efficiently. However, while gasification is not a new technology, neither is it as widely used as traditional combustion. There is relatively little experience operating gasification for the polygeneration of steam, hydrogen, and electricity; in 2003, Jones and Shilling[5] reported three gasification facilities operating for cogeneration and hydrogen production. Even less experience exists in operating these systems in conjunction with carbon capture and storage (CCS), which is an important technology to consider as it addresses the CO_2 concerns of exploiting heavy fossil fuels but also comes with its own set of trade-offs in terms of substantially increased costs and risks associated with operational performance. This lack of operating data associated with these systems introduces a significant amount of uncertainty into the study. This uncertainty is addressed in the analysis and is discussed in the Sensitivity Analysis and Discussion sections and the Supporting Information.

Alternatives to NG in the oil sands have been widely discussed (e.g., refs 3, 4, and 6), and some operators are already utilizing or considering utilizing asphaltenes and coke in their operations (e.g., Nexen,[7] Suncor[8]). Various studies have been conducted to determine the feasibility/suitability of alternative fuel gasification (e.g., Furimsky[9] and Bowman and duPlessis[10] looked at coke gasification). Studies included considerations of economics (e.g., Vartivarian and Andrawis[11] who found hydrogen from coke gasification was competitive at higher NG prices), environmental impacts (e.g., Furimsky[12] studied the impacts of polygeneration using byproduct gasification, while Söderbergh et al.[13] found that gasifying residues would increase GHG emissions), and the combination of the two (Ordorica-Garcia et al.[14] included coal gasification for hydrogen and electricity as an option in their optimization model). The implications of adding CO_2 capture to an asphaltenes-fuelled gasification polygeneration system in the oil sands have also been investigated.[15] While Ordorica-Garcia et al. did consider life cycle impacts in a previous, related study,[16] it does not appear that any of the aforementioned studies took a full systems approach to their analyses.

The results of this study provide insight into the environmental and financial trade-offs of replacing NG and are expected to be of interest to the oil sands industry, along with the government decision-makers tasked with regulating the industry's GHG emissions. However, the results can also be generalized to inform stakeholders in other industries where there could be benefits to replacing NG. For example, the refining industry utilizes NG and requires the production of electricity, steam, and hydrogen. As various and often broadly applicable regulatory approaches to reducing GHG emissions continue to be debated and developed (e.g., LCFS, cap and trade schemes, carbon taxes), it will become increasingly important for industries and other stakeholders to understand the full set of implications of the use of alternative fuels.

2. Methods

This study takes a systems/life cycle approach to investigate trade-offs associated with replacing a NG energy system with four alternative fossil fuel systems. For the case study, two generic oil sands projects are investigated: Mining with upgrading, and in situ SAGD with upgrading. Asphaltenes, coke, bitumen, and coal are investigated as potential alternatives to NG. Asphaltenes and coke are two heavy fractions of the bitumen and can be produced as byproducts of the upgrading process: They can be used on-site as fuels, stockpiled, or sold where markets exist. Asphaltenes, coke, and bitumen are readily available to oil sands operations and, in the case of the byproducts, currently have no direct fuel costs. Coal is examined since it is widely accessible and has the additional advantages of large reserves and relatively low cost in Alberta.

2.1. Energy and Hydrogen Demands of Oil Sands Projects. Oil sands projects require electricity and steam to extract the bitumen from the oil sands; in particular, SAGD requires large

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(7) Nexen Inc. *SAGD and Upgrader Integration*. http://www.nexeninc.com/Operations/Athabasca_Oil_Sands/Long_Lake/SAGD.asp, 2009.
(8) Suncor Energy Inc. *Voyageur Project, Volume 1B, Voyageur Upgrader, Project Application*; submitted to Alberta Energy and Utilities Board and Alberta Environment, March 2005.
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(14) Ordorica-Garcia, G.; Elkamel, A.; Douglas, P. L.; Croiset, E.; Gupta, M. *Energy Fuels* **2008**, *22*, 2660–2670.
(15) Ordorica-Garcia, G.; Wong, S.; Faltinson, J.; Singh, S. *Energy Procedia*. **2009**, *1*, 3977–3984.
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Table 1. Summary of Assumptions for Cases Considered[a]

system	fuel parameters: amount required [GJ/bbl_{SCO}]	price [2007 U.S. \$/GJ]	carbon content [wt %]	higher heating value [GJ/t]	key design parameters[b]
base cases					configuration: cogeneration, SMR, boilers
NG	M, 1.2; IS, 1.9	6.5	75[c]	54[c]	boiler efficiency: 80%; system efficiency[d]: M, 79%; IS, 80%
alternative cases−without CCS					configuration: E-gas gasification
asphalt	M, 1.5; IS, 2.4		81[e]	38[e]	system efficiency: M, 65%; IS, 64%
coke	M, 1.5; IS, 2.6		77[f]	30[f]	system efficiency: M, 61%; IS, 60%
bitumen	M, 1.6[h]; IS, 3.0[h]	M, 2.8; IS, 3.0	84[g]	42[g]	system efficiency: M, 66%; IS, 65%
coal	M, 1.7; IS, 2.8	2.0	48[i]	19[i]	system efficiency: M, 56%; IS, 56%
alternative cases−with CCS					
NG + CCS	M, 1.4; IS, 2.2	6.5	75[c]	54[c]	CO_2 capture rate: 92% (cogeneration, boilers); 90% (SMR) postcombustion (amine systems)
asphalt + CCS	M, 1.8; IS, 3.1		81[e]	38[e]	CO_2 capture rate: 92% precombustion capture (Selexol system)

[a] Asphalt, asphaltenes; bbl_{SCO}, barrel of synthetic crude oil (SCO) produced; CCS, carbon capture and storage; CO_2, carbon dioxide; M, mining with upgrading case; IS, in situ with upgrading case; SMR, steam methane reformer. [b] All efficiencies HHV and calculated as "'the sum of electricity, steam, and hydrogen produced' divided by 'energy in fuel fed to gasifier/cogeneration/SMR (excluding upstream energy)' multiplied by 100%". [c] NG carbon content based on ref 19, HHV from ref 19. [d] NG system efficiency includes NG used as a feedstock for the SMR. [e] Asphaltenes carbon content based on ref 20, HHV from ref 21. [f] Coke carbon content and HHV ref 22. [g] Bitumen carbon content and HHV ref 22. [h] Bitumen consumption includes "upstream" bitumen. [i] Coal carbon content and HHV taken from ref 19 for Wyoming Powder River Basin coal.

quantities of steam. Upgrading also requires electricity and steam, as well as hydrogen which can be used to hydrotreat the bitumen (to reduce sulfur) and to hydrocrack it (to break some of the long hydrocarbon chains) to improve the quality of the product in order that it can be sold as a higher value synthetic crude product.

The electricity, steam, and hydrogen demands for the case study were determined through a review of publicly available regulatory submissions (see the Supporting Information). Average demands were used as point estimates in this analysis and were held constant across the systems considered (see Table 2). The determined energy demands compare reasonably well with those presented in the literature;[16] however, a sensitivity analysis of key parameters was also conducted. A further discussion of uncertainties is presented in the Supporting Information.

2.2. Energy and Hydrogen Supply Systems. Three categories of energy and hydrogen supply systems are analyzed: the NG systems that represent current operations ("base cases"), the alternative fuel systems, and the systems that employ CCS technology (in total 14 cases). Summaries of the characteristics of the cases considered and primary assumptions are presented in Tables 1 and 2. Again, additional discussion of uncertainties is presented in the Supporting Information.

Natural Gas Cases: M-, IS-NG. The NG base cases [for the mining (M-) and in situ (IS-) projects] consist of electricity and steam production through cogeneration with supplementary boilers and hydrogen production by steam methane reforming (SMR). This system configuration, commonly used in oil sands projects, as well as the associated upstream operations, is shown in Figure 1. Oil sands operations may also meet their energy and hydrogen demands from the provincial electricity grid or from colocated operations; however, these options are beyond the scope of this study. Key assumptions and data for the NG cases are identified in Table 1, and further details on the cases are in the Supporting Information.

Alternative Fuel Cases: M-, IS-Asphaltenes; M-, IS-Coke; M-, IS-Bitumen; M-, IS-Coal. These are polygeneration systems using E-Gas gasification technology, based on systems presented by Amick.[17] In these systems, fuel is fed to the gasifier to produce a synthesis gas rich in hydrogen and carbon monoxide (based on ref 18), which can then be combusted to produce steam and/or electricity or purified to produce hydrogen, while "waste" heat can be used to generate additional steam. Systems in ref 17 were modified in this study to produce electricity, steam, and hydrogen in the appropriate ratios (per energy demands above; see the Supporting Information). The system fuelled by asphaltenes is shown in Figure 1 as an example, while all cases are summarized in Table 1. The system boundaries for the coke system are identical to those of the asphaltenes, while those of the bitumen system extend to include bitumen extraction. Similarly, the coal system includes coal mining and transport.

Production of the asphaltenes and coke is not included as an "upstream" activity in the energy supply systems nor are prices assigned to these fuels as they are assumed to be produced as byproducts that would otherwise be stockpiled on-site and to be produced in sufficient quantities to meet the systems' demands. Should a market develop for asphaltenes or the existing coke market expand, prices would need to be assigned (this is investigated in the sensitivity analysis). With the use of the byproducts in the gasification system, they will no longer need to be transported to a stockpile. As such, the systems are credited with the emissions avoided. However, the gasification process will produce a slag that will require disposal. The bitumen systems are unique in that the use of bitumen to generate process inputs will increase the energy demands per unit of SCO: To produce a barrel of SCO, not only must the bitumen for processing be extracted but also "extra" bitumen to

(17) Amick, P. *Petroleum Coke Gasification Synergies for Refineries*; Presentation to the Gulf Coast Power Association, http://www.gulfcoastpower.org/default/S05-amick.pdf, 2005.

(18) Gough, R. Case Studies: Real-World Applications of the Petcoke Gasification Technology... In *Petcoke Gasification: Clean Cost-Effective Energy for Refiners*; Hart Energy Publishing LP: 2004; pp 10−14.

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(21) OPTI Canada Inc. *OPTI Canada Long Lake Project, Application for Commercial Approval, Volume 1, Technical Information, Section B−Project Description*; December 2000.

(22) Jacobs Consultancy. *Alternative Fuels Study Technology Review* (*Volume 1*); Prepared for Alberta Energy Research Institute and Alberta Environment, December, 2008.

Table 2. Summary of Study Assumptions[a]

	Energy and Hydrogen Demands
electricity	M, 0.096 GJ/bbl_{SCO}; IS, 0.051 GJ/bbl_{SCO}
steam	M, 0.41 GJ/bbl_{SCO}; IS, 1.1 GJ/bbl_{SCO}
hydrogen	M, IS, 0.42 GJ/bbl_{SCO}
	Analysis Assumptions
spatial boundaries	process-based LCA approach: Province of Alberta; EIO-LCA approach: Canadian economy[b]
amortization period	30 years
discount rate	15%
currency	2007 U.S. dollars
CO_2 storage period (modeled)	100 years
	Life Cycle Stages
construction and decommissioning	steam, electricity and hydrogen production facilities (other oil sands infrastructure not included) natural gas: pipeline coal: rail line, rolling stock manufacture CCS: CO_2 pipeline, CO_2 storage infrastructure
operations	steam, electricity and hydrogen production only (other oil sands operations not included)
maintenance	energy system equipment maintenance
slag disposal, avoided stockpiling	landfilling of slag produced in gasification system coke and asphaltenes cases are credited with impacts avoided through their use (i.e., those associated with stockpiling)
upstream	natural gas: extraction and transport by pipeline 845 km coke and asphaltenes are byproducts that are assumed to be produced regardless of whether they are used by the energy system; impacts of production are not included in the system bitumen: mining and/or extraction of "upstream" bitumen coal: mining and transport by rail 450 km
CO_2 transport and storage	CO_2 transported 400 km by pipeline and injected into a depleted oil reservoir (not used for enhanced oil recovery)

[a] bbl_{SCO}, barrel of synthetic crude oil (SCO) produced; CCS, carbon capture and storage; CO_2, carbon dioxide. [b] Reference 23.

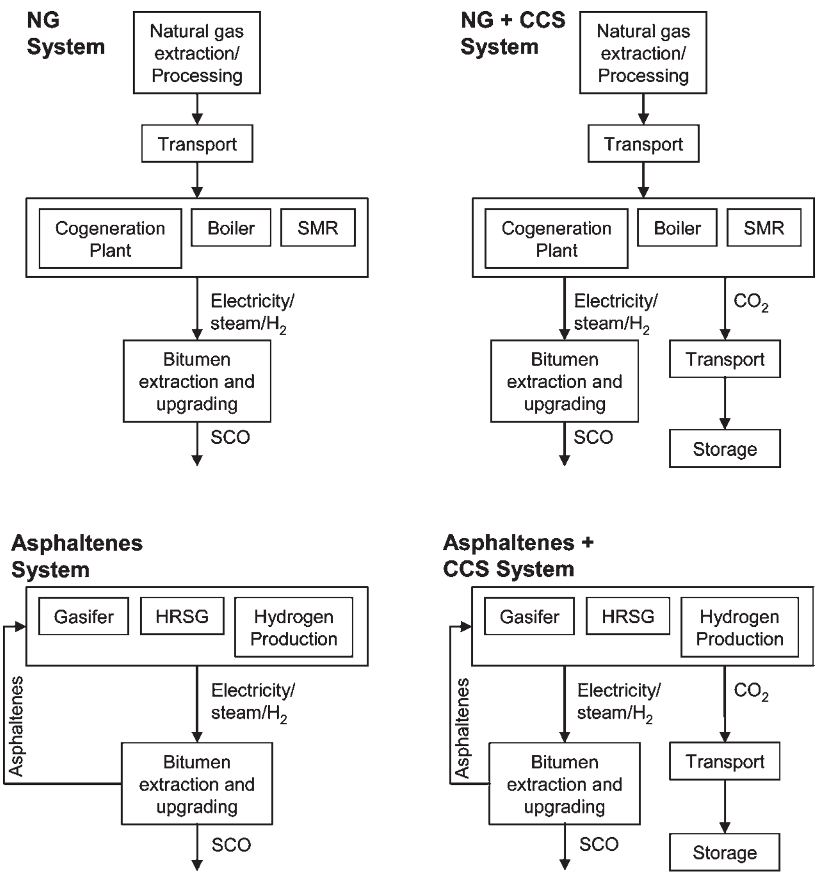
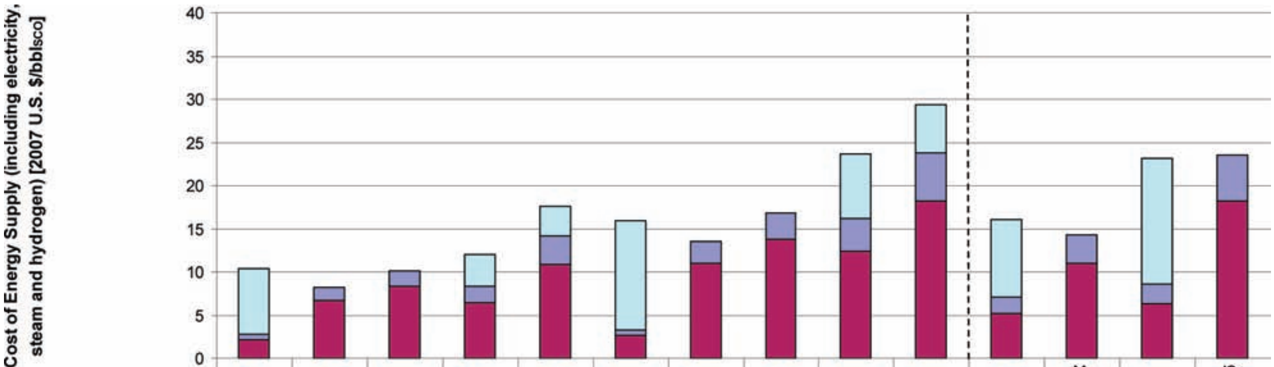


Figure 1. Simplified schematic diagrams of the natural gas (NG) and asphaltenes systems, with and without carbon capture and storage (CCS). The systems are identical for the mining and in situ cases; only the energy demands differ. Where appropriate, the extraction, processing, and transport of the fuel are included as well as the construction and decommissioning of the energy and hydrogen supply facilities on the sites of the oil sands projects. CO_2, carbon dioxide; H_2, hydrogen; HRSG, heat recovery steam generator; SCO, synthetic crude oil.



	M-NG	M-Asphalt	M-Coke	M-Bitumen	M-Coal	IS-NG	IS-Asphalt	IS-Coke	IS-Bitumen	IS-Coal	M-NG+CCS	M-Asphalt+CCS	IS-NG+CCS	IS-Asphalt+CCS
CCS cost increase											6	6	7	10
Fuel	7.6			3.6	3.4	13			7.4	5.6	9.0		15	
Non-fuel O&M	0.63	1.5	1.8	1.9	3.3	0.67	2.5	3.0	3.8	5.6	2.0	3.2	2.2	5.3
Capital	2.1	6.7	8.3	6.5	11	2.6	11	14	12	18	5.1	11	6.4	18

Figure 2. Financial cost of the natural gas (NG) and alternative fuel systems for oil sands extraction and upgrading, with and without carbon capture and storage (CCS). "Fuel" includes NG, bitumen, and coal; any ancillary fuels used in the systems (e.g., diesel for transportation) are included in the "Non-fuel O&M"; O&M, operations and maintenance. Other abbreviations as per Table 1.

fuel the gasifier (0.21 barrels (bbl) of bitumen per barrel of SCO produced for the mining project and 0.35 bbl_{bit}/bbl_{SCO} for the in situ project). The energy required to extract this "extra" bitumen (including the electricity and steam ultimately generated from the bitumen system itself; see the Supporting Information) is considered "upstream" in the same way as is the energy used for NG extraction.

CCS Cases: M-, IS-NG + CCS; M-, IS-Asphaltenes + CCS. CCS was investigated for application to the NG and the asphaltenes systems (the latter as representative of the gasification systems), as illustrated in Figure 1. In the NG with CCS system, the cogeneration plant and boilers are assumed to share a single amine capture system, but the exhaust stream from the SMR unit is assumed to be sufficiently distinct as to require a separate capture system.

2.3. Systems Environmental and Financial Implications. Life cycle assessment (LCA) and life cycle costing (LCC) methods are applied to analyze the energy systems. These life cycle approaches ensure that the implications of both on-site operations and upstream activities (see Figure 1) are included in the analysis.

A "hybrid" LCA approach is utilized which combines both process-based and economic input−output (EIO) LCA (see Hendrickson et al.[24] for details on these methods). The functional unit is a bbl of SCO. The metrics examined are financial cost, GHG emissions (kilograms of CO_2E), and energy use (megajoules). Table 2 identifies the key assumptions made in this analysis (see the Supporting Information for additional details).

The LCC analysis determines the financial cost associated with the energy system (electricity, steam, and hydrogen supply) only, not the cost of the full oil sands project. Within the analysis, a penalty (50%) is applied to some costs to account for the Northern Alberta setting. Costs in this region have historically been higher than those in locations further south due to labor and material pressures experienced in the region, as well as the distance between the projects and major population centers. The cost penalty is investigated in the sensitivity analysis.

(23) Charpentier, A. D.; MacLean, H. L. *Input-Output Approach in the LCA of Oil Sands Project*; Input-Output Symposium following the International Society for Industrial Ecology 2007 Conference. Toronto, ON, 2007. Model available at http://www.eiolca.net/

(24) Hendrickson, C. T.; Lave, L. B.; Matthews, H. S. *Environmental Life Cycle Assessment of Goods and Services: An Input-Output Approach*; Resources for the Future: Washington, DC, 2006.

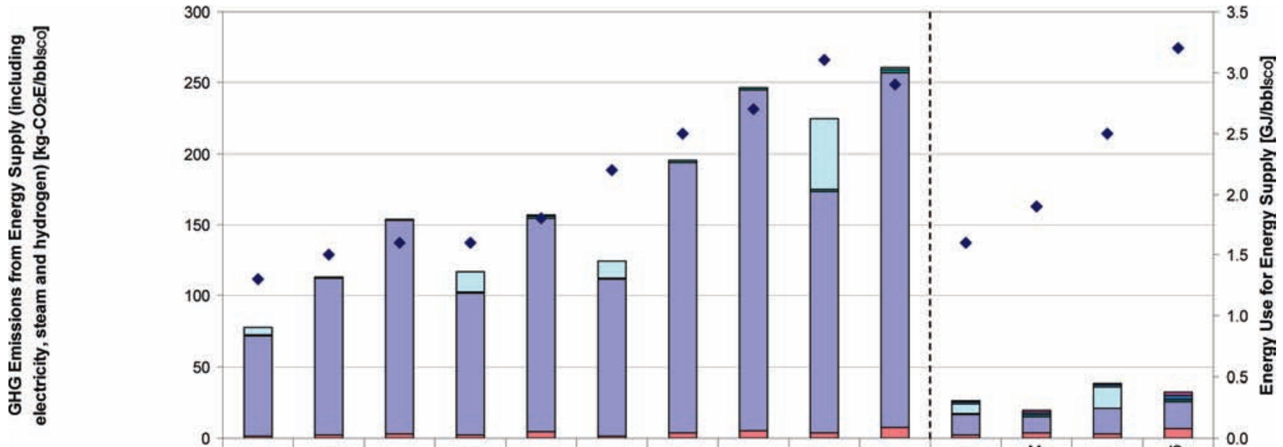
The cost-effectiveness of mitigating GHG emissions through the use of the alternative cases with CCS rather than the NG base cases is calculated (dollars per tonne of CO_2E avoided). The cost is calculated by dividing the difference in cost per unit of energy output between the CCS system and a baseline system by the difference in GHG emissions per unit of energy output between those same two systems. The choice of baseline is critical as it can have a significant impact on the results; a judgment has to be made about which baseline is appropriate in each case. The NG base cases (i.e., without CCS) were chosen as these represent the current technology of choice for oil sands operators.

3. Results

3.1. Financial Results. Figure 2 summarizes the cost of energy supply (the costs to satisfy the hydrogen, electricity, and steam requirements per bbl of SCO) for each of the 14 cases considered; note that this is not the entire cost of the oil sands project but just the energy system component. On a financial basis, several of the alternative fuels are competitive with NG. As well, mining energy costs are 40−50% lower than in situ energy costs, consistent with the lower energy demands of the mining with upgrading case.

All of the alternative fuel systems considered require investment in gasification technology, which has a higher capital cost than the NG system by more than a factor of 2. However, this additional capital is offset by lower fuel costs. This shift in risk from operating to capital is central to the decision of whether to replace NG systems with the heavier fossil fuel systems considered in this study. The byproducts of bitumen upgrading (asphaltenes and coke) are the cheapest options in part because they are produced on-site and are essentially "free" sources of energy. Bitumen and coal are less attractive as they require more expensive capital equipment then the NG systems in addition to fuel costs which, while less than NG, are still significant. Bitumen is a unique system as it is used to supply energy for both the oil sands projects (as with all of the other fuels) as well as the "upstream" operations that extract the fuel (bitumen).

Given the current regulatory/political environment (i.e., current and future climate policies, LCFS, and the "dirty oil" label), it is unlikely that a new oil sands operation would



GHG Emissions [kg-CO2E/bblsco]	M-NG	M-Asphalt	M-Coke	M-Bitumen	M-Coal	IS-NG	IS-Asphalt	IS-Coke	IS-Bitumen	IS-Coal	M-NG+CCS	M-Asphalt+CCS	IS-NG+CCS	IS-Asphalt+CCS
CO2 Storage											0.72	1.4	1.1	2.3
CO2 Transport											1.3	1.8	1.5	2.6
Upstream	5.5			14	0.98	12			50	1.6	7.2		15	
Stockpiling		-0.015	-0.021				-0.026	-0.034				-0.019		-0.032
Slag Disposal		1.4E-03	4.7E-04	1.9E-05	1.7E-03		2.3E-03	7.8E-04	3.1E-05	2.9E-03		1.7E-03		2.9E-03
Maintenance	0.22	0.70	0.87	0.62	1.14	0.24	1.2	1.5	1.0	1.9	0.47	1.0	0.53	1.7
Operations	71	110	150	100	150	110	190	240	170	250	14.0	11	18	19
Const/Decomm	1.4	2.4	3.0	2.1	4.8	1.8	4.0	5.0	3.5	7.4	2.6	4.0	3.4	6.6
Energy Use [GJ/bbl]	1.3	1.5	1.6	1.6	1.8	2.2	2.5	2.7	3.1	2.9	1.6	1.9	2.5	3.2

Figure 3. Greenhouse gas (GHG) emissions and energy use of natural gas (NG) and alternative fuel systems, with and without carbon capture and storage (CCS). Abbreviations as per Table 1.

build a gasification system for any of the alternatives considered in this analysis without also implementing CCS to reduce the CO_2 emissions from the system. As shown in Figure 2, adding CCS to the systems significantly increases their costs. The cost of energy supply is increased by approximately 40% for the NG cases and 70% for the asphaltenes cases. This cost increase for CCS is on the order of \$6 to \$10/bbl_{SCO}. However, GHG emissions can be reduced more (see following section) and at a lower system cost in the asphaltenes cases than in the NG cases; this is expected given the relative ease of capturing CO_2 from the concentrated, higher pressure gasification exhaust compared to the more dilute, lower pressure NG combustion exhaust.

Under the base conditions, the CO_2 avoidance cost is \$66/tonne of CO_2E for the mining asphaltenes CCS case and \$87/tonne for the in situ asphaltenes CCS case. In order for a mining or in situ operator to prefer the asphaltenes system with CCS over a NG system without CCS, the penalties for emitting CO_2 would have to be at least equal to the above values. These results confirm that CCS will not be implemented for oil sands energy systems without some financial incentive or regulatory requirement (beyond what is currently required).

3.2. Energy Use and GHG Emissions. Every alternative energy (without CCS) system considered uses significantly more energy and emits more GHGs than the NG base cases (Figure 3). The emissions for the mining and in situ cases for asphaltenes are the lowest of the alternatives but are still about 54% and 58% greater than those of the NG cases, respectively, and their energy use is about 15% greater. The difference in emissions between NG and the alternatives is more pronounced in the in situ cases simply due to the increased energy demands for this method of extraction compared to the mining method. The advantages of asphaltenes over the other three alternatives are primarily explained by their heating value (higher than those of coke and coal), carbon content (lower than that of bitumen), and system efficiency (higher than that of coke and coal; efficiency is a function of heating value as described in the Supporting Information). The combination of the heating value and carbon content for each fuel partially explains why the energy use and GHG emissions do not correlate consistently across all cases. Although coal has a lower carbon content than the other alternative fuels, it also has a much lower heating value, resulting in GHG emissions more than double those of the NG cases. Bitumen extraction is the most energy intensive feedstock production method considered, with the resulting highest upstream energy use and associated GHG emissions of any fuel, including NG.

The operations stage of the systems dominates the life cycle GHG emissions (and energy use) representing about 85−95% of life cycle emissions, confirming that improvement efforts should be focused on this stage. When CCS is added, the GHG emissions drop considerably (as expected) but energy use increases significantly due to the energy penalty associated with operating the capture and compression systems. Energy requirements increase by 13−23% for the NG cases whereas the energy penalty for gasification of asphaltenes results in a 27−28% increase. This is perhaps of less concern for the asphaltenes system (byproduct fuel with no associated cost) than for the NG system (concerns regarding price volatility). However, emissions from all CCS cases are less than the lowest base case considered (M-NG) by at least a factor of 2. The asphaltenes with CCS cases produce emissions that are 25% of those of the NG base cases, which demonstrates that it is possible to switch to a heavier feedstock but have resulting emissions that are lower than current emissions from projects using NG. In addition, the asphaltenes cases with CCS have lower emissions than the NG cases with CCS. This is primarily due to the larger upstream emissions associated with NG production (compared to no upstream emissions in the asphaltenes case). However, while the two systems have CO_2 capture rates of 92% (90% for the SMR), much more CO_2 is actually captured, compressed, transported, and stored in the asphaltenes with CCS system. For example, in the mining cases, 0.067 tonne of CO_2/bbl_{SCO} and 0.13 tonne/bbl_{SCO} are captured and stored for the NG with CCS and asphaltenes with CCS cases, respectively.

3.3. Sensitivity Analysis. The case study presented shows the energy use, GHG emissions, and financial costs for realistic but hypothetical energy systems to support the needs of oil sands projects. Polygeneration of hydrogen, steam, and electricity adds significant complexity to the systems studied, and there is relatively little operational experience with polygeneration facilities producing these products on the necessary scale and in the appropriate ratios. Therefore, this analysis has considerable uncertainty and variability. A sensitivity analysis was conducted on over 20 key parameters, selected on the basis of their inherent importance to the results, their relative uncertainty, or their potential design variability, to determine their influence on the results and to thus identify the major drivers. The most important parameters impacting the results are discussed below.

Financial Analysis. The gasification of asphaltenes is the cheapest option of those considered, followed closely by the NG and coke systems. Given the inherent uncertainty in the analysis, it is difficult to conclude that this rank of competitiveness is robust. Therefore, it is worthwhile to explore the relative contributions of the most important factors and under what conditions it would be expected that one system would be preferred on a financial basis to another. A major driver for the cost of the NG systems is the fuel price whereas a major driver for the heavy fuels gasification systems is the capital costs of the systems themselves. These and other important factors are explored below and are categorized by influence on either the capital or operating cost portion of the system cost.

The first set of parameters considered relates to fuel costs and operating conditions. The NG price assumed in the case study was \$6.5/GJ. At this price the in situ NG case is more expensive than the asphaltenes case but cheaper than the other heavy fuels cases. However, a NG price between \$4.9 and \$5.6/GJ would make the NG case the least cost option; this price range is well within the range of variability seen in the NG market over the past decade.[25] It was assumed under the base conditions that the asphaltenes and coke cases would not incur a fuel cost as both fuels were produced as byproducts in the upgrading process. However, it is foreseeable that in the future (or if a facility is required to supplement their own production of the fuels by purchasing from an external source to satisfy their energy and hydrogen demands) a cost will be associated with these fuels. A price higher than between \$0.62 and \$1.3/GJ for asphaltenes (lower than the current average price of coal in Canada) would drive the cost of the in situ asphaltenes case higher than that of the NG case. The cost of the in situ coke case is already higher than that of the NG case, so any price for coke would simply increase the cost difference, making the coke case less attractive.

The efficiency of the in situ asphaltenes case under the base conditions was assumed to be 64% HHV. If this efficiency is lowered to 55% HHV, the asphaltenes case becomes more expensive than the NG case. While slightly below the range represented by the examples of gasification "multiproduct" systems cited by the IPCC,[26] it is conceivable that a facility could operate at this efficiency. In addition, an efficiency penalty of 20% (relative) is applied to the system when CCS is added to account for CCS equipment requiring additional energy to operate, thus reducing the overall system efficiency. Even a small change in this penalty will make the in situ asphaltenes with CCS case less competitive than the NG with CCS case.

The capital costs of the gasification systems in this analysis are highly uncertain and influenced by several factors including the cost penalties associated with location constraints, cost of materials and labor, and the performance of the gasification system (the lower the efficiency the more throughput required and therefore the larger the gasification system required to deliver the same energy/hydrogen products). The amortized capital cost for the in situ asphaltenes case is \$11/bbl_{SCO} under base conditions. A relatively small increase in the capital cost (11−22%) would result in the in situ asphaltenes case becoming more expensive than the NG case. Given our uncertainty about the actual cost of building a polygeneration gasification facility specifically for application in the oil sands, the capital cost is an important determinant of the overall competitiveness of the cases considered.

General factors such as location constraints and the costs of materials and labor apply to both the NG and gasification systems. For example, the ENR construction cost[27,28] and CEPCI[29] indices report cost increases of 22 and 33%, respectively, over the years 2002−2007. The increase in costs has arisen due to increased material costs globally and a constrained labor force, the latter particularly an issue for Alberta. High costs have been particularly prominent in Northern Alberta, which has experienced historic rates of growth due to rapid expansion of oil sands projects. Since the economic downturn during 2008−2009, these inflated costs have dropped significantly and there is uncertainty about which direction they will trend over the next decade. While NG systems generally have lower capital costs than gasification systems, they are still on the order of several hundred million dollars and are therefore also affected by such trends. The base condition assumption was a 50% location-specific cost penalty (on all NG and alternative cases; see the Supporting Information for an identification of specific costs to which this was applied) to account for the fact that the cost estimates obtained were generally from U.S. locations and were being applied to a remote location with a high demand for materials and a constrained labor market. A penalty over 80% would change the results in that the in situ NG case would become more competitive than the asphaltenes case. This value is well within the range of inflation factors applied to oil sands projects in Alberta (which can be as high as 100%).

(25) United States Department of Energy, Energy Information Administration. *U.S. Natural Gas Electric Power Price* (*dollars per thousand cubic feet*), *Annual*; http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3a.htm, 2009.

(26) Intergovernmental Panel on Climate Change. *IPCC Special Report on Carbon Dioxide Capture and Storage*; Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Metz, B., Davidson, O., de Coninck, H. C., Loos, M., Meyer, L. A., Eds.; Cambridge University Press: Cambridge, U.K., 2005.

(27) *Eng. News. Rec.* **2002**, *248* (7), 36.

(28) *Eng. News. Rec.* **2007**, *258* (8), 22.

(29) *Chem. Eng.* **2008**, *115* (13), 64.

Table 3. Sensitivity of the CO_2 Avoidance Cost to Variation in Select Parameters (All Values in \$/tonne-CO_2E Avoided)[a]

			relative change in parameter from original case					
			efficiency			gasification CCS capital cost penalty		
			−30%	0%	+30%	−30%	0%	+30%
relative change in parameter from original case	gasification capital cost	−30%	94	15	−22	8.3	15	22
		0%	210	85	30	76	85	96
		+30%	320	160	82	140	160	170
	gasification CCS capital cost penalty	−30%	190	76	23			
		0%	210	85	30			
		+30%	220	96	37			

[a] Original parameter values: efficiency = 64%; gasification CCS capital cost penalty = 17%; gasification capital cost = 18 (2007 U.S. dollars)/bbl_{SCO} or about 3.0 billion (2007 U.S. dollars) at a production rate of 75 000 bbl_{SCO}/day.

Uncertainties in many of the inputs to the CO_2 avoidance costs compound to make the resulting uncertainties in these values high and, correspondingly, interpretation particularly challenging. Table 3 demonstrates how the avoidance cost can change significantly from the base condition by varying, within plausible ranges, only three of the key parameters in the analysis. The table shows the results for the asphaltenes in situ case where the avoidance cost is \$85/tonne-CO_2E under the base conditions, when only operating and maintenance (as opposed to life cycle) emissions are considered. Depending on the values assumed, it is possible to obtain avoidance costs between −\$22 and \$320/tonne-CO_2E for the same system.

Other factors were explored that did not significantly impact the financial results. These included SOR (while it has a significant impact on the overall cost, it does not significantly change the preference between NG and the alternatives), boiler efficiency, discount rate, hydrogen required, and coal price.

GHG Emissions. The most important factors in determining the GHG emissions of the systems include the heavy fuel characteristics (e.g., HHV, composition), CO_2 capture rate, and upstream NG emissions. Depending on the fuel characteristics, the rank (in terms of GHG emissions) of the heavy fuels could change. For example, it may be possible to obtain better quality coke and poorer quality asphaltenes than those considered under the base conditions such that the emissions of the coke case would be lower than those of the asphaltenes case. However, no combination of improved characteristics for these fuels results in emissions lower than those of the NG cases.

Current CCS systems are being designed to capture more than 90% of the CO_2 passing through the equipment. However, this capture rate has yet to be demonstrated for all systems considered, and under different conditions it might be appropriate to capture smaller amounts of CO_2. This factor will increase or decrease the net emissions and can change the ranking of the different cases considered.

The results in Figure 3 show that the life cycle emissions for the asphaltenes with CCS cases are lower than those for the NG with CCS cases. This difference is due in large part to the upstream NG emissions. Estimates for these emissions vary greatly in the literature (see the Supporting Information), and further work is required to reconcile these values. However, even with the use of a low estimate for these emissions (NG system/without per Table S5 in the Supporting Information), the GHG emissions for the in situ NG with CCS case remained higher than those of the asphaltenes with CCS case.

The overall conclusion of the sensitivity analysis is that while the case study presented in the paper is realistic and reflects good engineering design and estimation, the results can be different depending on the specific project requirements, the economic environment in which these projects will be constructed, and how these technologies will actually perform as part of the overall oil sands operation and in the climate of Northern Alberta. As these projects are built and operational data collected, these results can be further refined. The sensitivity analysis has elucidated the factors that are extremely influential in the study and that should therefore be explored extensively in evaluations for specific projects. From a financial perspective, the price of NG, CCS cost penalty, efficiency of gasification, the capital costs of the gasification system, and the baseline system characteristics are the most important parameters. Also, the analysis provides a note of caution that a combination of plausible assumptions could lead to CO_2 avoidance cost estimates that are either so low or so high as to not be believed. Therefore, care must be employed when interpreting avoidance cost results. The most important factors in determining the GHG emissions of the systems include the heavy fuel characteristics, CO_2 capture rate, and upstream NG emissions.

4. Discussion

The decision to replace NG with an alternative fossil fuel requires analysis of multiple factors. Considerations include those related to the environmental, financial, and technological performances that are examined here, as well as others such as system operating experience, risk attitude, fuel security, and other environmental impacts.

This analysis focused on the use of gasification for the polygeneration of hydrogen, steam, and electricity from alternative fossil fuels. Gasification is not a new technology, but neither is it as widely used as combustion, which may make operators hesitant to switch away from NG. Another consideration is that shifting from NG to the gasification of heavy fossil fuels shifts risks from NG price volatility to risks associated with the capital investment required for the gasification system. One's belief about the future price of NG will heavily influence the choice of which risk to accept. Another risk prompting replacement of NG is concern around resource availability. Care must be taken to ensure that this does not become an issue for the chosen replacement fuel. While the U.S. and Canada have vast coal reserves, concerns may arise when using byproducts as primary fuels. In the case study, the coke system and the in situ asphaltenes case consume fuel at rates greater than sample production rates. For example, the proposed Voyageur upgrader would produce coke at a rate of about 0.03 t/bbl_{SCO} (based on ref 8). This is lower than the consumption rate of the mining system designed here and just slightly more than a third of that for the in situ system.

A solution may be to cofire the byproducts with another fuel, such as coal or biomass, but implications of these options would need to be examined. Alternatively, it may be possible to alter the project to produce more byproduct (e.g., ref 12), although this could in turn impact the energy demands to be met, or the system costs. Other factors that may need to be examined are environmental impacts beyond GHG emissions and energy use (e.g., criteria air contaminant emissions, land use impacts), with particular attention to those that are currently subject to regulation or that may become so within the project's operating life.

By examination of trade-offs between GHG emissions, energy use, and financial cost, this analysis presents a basis for discussion regarding the replacement of NG with alternative fossil fuels. Still, the uncertainty in the results must be considered (as emphasized by the sensitivity analysis), as must the specific characteristics of the case study; for example, the case study is based on specific energy demands, however these could vary depending both on the quality of the bitumen recovered from the oil sands deposit as well as the quality of the SCO produced for sale.

If an assessment of a particular oil sands operation was desired, high-quality, project-specific data could be substituted into the analytical framework utilized in this study. The analysis could also be expanded to include other alternative fuels and energy systems, particularly those expected to have lower life cycle GHG emissions (e.g., nuclear, biomass, geothermal systems). As with the fossil fuel systems, these options have unique advantages and disadvantages and their associated trade-offs would need to be thoroughly assessed. Finally, this study's analytical framework could be adapted and applied to other oil sands technologies (e.g., cyclic steam stimulation or an emerging technology) or to other industries. For example, the framework could be adapted to examine a polygeneration application such as for an oil refinery currently using NG for electricity, steam, and hydrogen production. Different combinations of technologies (e.g., different gasification technologies) and applications (e.g., differing requirements for hydrogen, steam, electricity, and other products) would also be useful comparisons to consider in future work.

The systems comparison of four potential replacements for NG provides insights into the trade-offs operators must consider before deciding to switch fuels and systems; in particular, there are trade-offs to be made between the concerns around NG use (e.g., price volatility, resource availability) and potentially increased emissions, cost, and energy use. While none of the potential substitutes investigated here clearly performs better than NG against all criteria, if concern regarding NG consumption outweighs the potential drawbacks of a substitute fuel, an asphaltenes gasification system employing CCS technology appears promising. Comprehensive, systems-level investigations such as this one can inform the decision-making of operators and regulators for a range of industries and provide a basis for more project-specific analyses, while identifying key areas where more detailed study is warranted. Through such careful analyses, a balance can be struck between environmental, financial, and other objectives.

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Supporting Information Available: Further details on the energy demand determination, the design and specifications of the energy systems, the life cycle analyses, and the sensitivity analysis. This material is available free of charge via the Internet at http://pubs.acs.org.