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Variability and Uncertainty in Life Cycle Assessment Models for Greenhouse Gas Emissions from Canadian Oil Sands Production

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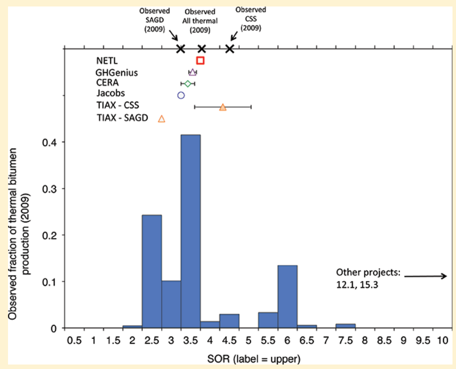
S *Supporting Information*

ABSTRACT: Because of interest in greenhouse gas (GHG) emissions from transportation fuels production, a number of recent life cycle assessment (LCA) studies have calculated GHG emissions from oil sands extraction, upgrading, and refining pathways. The results from these studies vary considerably. This paper reviews factors affecting energy consumption and GHG emissions from oil sands extraction. It then uses publicly available data to analyze the assumptions made in the LCA models to better understand the causes of variability in emissions estimates. It is found that the variation in oil sands GHG estimates is due to a variety of causes. In approximate order of importance, these are scope of modeling and choice of projects analyzed (e.g., specific projects vs industry averages); differences in assumed energy intensities of extraction and upgrading; differences in the fuel mix assumptions; treatment of secondary noncombustion emissions sources, such as venting, flaring, and fugitive emissions; and treatment of ecological emissions sources, such as land-use change-associated emissions. The GHGenius model is recommended as the LCA model that is most congruent with reported industry average data. GHGenius also has the most comprehensive system boundaries. Last, remaining uncertainties and future research needs are discussed.



INTRODUCTION

As conventional oil production becomes constrained, transportation fuels are being produced from low-quality hydrocarbon resources, such as bitumen deposits and other unconventional fossil resources. These include oil sands, enhanced oil recovery, coal-to-liquids and gas-to-liquids synthetic fuels, and oil shale.

Production of crude bitumen from the oil sands was almost 1.5 M bbl/d in 2009.[1,2] Production of liquid products from oil sands, including raw bitumen and synthetic crude oil (SCO), reached 1.35 M bbl/d in 2009. This represents an increase from ≈600 k bbl/d in 2000.[3] Current plans for expansion of production suggest over 7000 k bbl/d of capacity in all stages of operation, construction, and planning.[2]

In general, liquid fuels produced from unconventional resources have higher energy consumption per unit of fuel produced than those produced from conventional petroleum deposits. This is due to the higher energy intensity of primary resource extraction and the energy requirements of hydrocarbon processing and upgrading. Greenhouse gas (GHG) regulations such as the California Low Carbon Fuel Standard (LCFS) and European Union Fuel Quality Directive seek to properly account for the GHG intensities of these new fuel sources.

This paper examines models of upstream GHG emissions from Alberta oil sands production. The goal of this work is to understand the validity and comparability of previously published life cycle assessment models of GHGs from oil-sands-derived fuels, and to compile a range of emissions factors for oil-sands-derived fuel streams. Assumptions and data inputs to models are compared with observed data. Recommendations are then made for the use of these LCA results and for future research needs.

OVERVIEW OF OIL SANDS PRODUCTION METHODS

Oil sands are a mixture of sand and other mineral matter (80–85%), water (5–10%), and bitumen (10–18%).[4] Bitumen is a dense, viscous mixture of high-molecular-weight hydrocarbons. Bitumen is either diluted or upgraded to SCO before shipment to refineries for processing into liquid fuels.

Oil sands extraction. Bitumen is produced through surface mining or in situ production processes. Surface mining requires removal of overburden and mining of the bitumen/sand mixture (ore). The ore is transported to processing facilities where it is mixed with hot water, screened, and separated into bitumen and tailings.[4] A variety of in situ techniques exist, the most commonly applied being steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).

Mining-Based Bitumen Production. Overburden removal is typically performed with a truck-and-shovel operation.[5] Bitumen ore is mined with diesel or electric hydraulic shovels. Large haul trucks move the ore to crushing and slurrying

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centers for hydrotransport to extraction centers (diesel-powered using fuel generated on site as SCO). Some processing equipment is powered with electricity coproduced on site from natural gas, upgrading process gas, or coke.[6] Published estimates of mining energy consumption vary by an order of magnitude (0.3–3.6 GJ/m^3 of SCO).[6–8] Given that the high end of this range (3.6 GJ/m^3 SCO) represents some 10% of the energy content of the SCO, this is most likely an overestimate of mining energy inputs.

At the extraction facilities, bitumen froth (60%+ bitumen, remainder water) is separated from sand, requiring warm water and consuming ≈40% of the energy used to produce a barrel of SCO.[5] Within integrated mining operations, upgrader by-products such as process gas and coke provide heat and power for the separation process.[6] After primary separation, bitumen froth is treated to remove water and solids, using naphtha or parrafinic solvents. This produces clean bitumen ready for upgrading to synthetic crude oil. Energy costs for separation of the bitumen are estimated at 0.9 GJ/m^3.[8,9]

In Situ Bitumen Production. Bitumen and heavy oil in the oil sands region are generally produced in situ using thermal methods such as CSS and SAGD, although smaller amounts of cold (primary) production of extra-heavy oil does occur in the oil sands region.[5,10] A significant reduction in hydrocarbon viscosity with modest increases in temperature allows bitumen to flow to the well for production. Thermal in situ production is generally more energy-intensive than mining-based production.

GHG emissions from in situ production result primarily from fuels combusted for steam generation. A key indicator is the steam oil ratio (SOR), often measured as cubic meters of cold-water equivalent (CWE) steam injected per cubic meter of oil produced. SORs for commercial thermal in situ recovery projects generally range from 2 to 5, with the production-weighted industry average being 3.6 in 2009.[10] This represents the volume-weighted average of projects listed in Energy Resources Conservation Board data sets as "commercial-CSS" and "commercial-SAGD". Primary production of bitumen is not included because steam is not injected. SORs above 10 have been reported, but these represent transient effects at the outset of SAGD operations.[10] SORs have tended to improve over time with the maturation of SAGD technology.

The SOR is not the sole driver of in situ extraction emissions.[11] The amount of energy required to convert water to steam for injection depends on steam quality and pressure, the efficiency of steam generation, and heat recovery from produced fluids. Because of the requirement for 100% quality steam, the energy content of steam for SAGD projects is higher than that in heavy oil TEOR projects,[12] at ≈2.8 GJ/m^3.[11,13] Steam enthalpy varies little at relevant SAGD pressures, but the partitioning between sensible and latent heat changes across low- and high-pressure SAGD operating pressures.[11] To produce 100% quality steam, 80% quality steam is first produced in once-through steam generators (OTSGs), and condensate is returned to the boiler using vapor–liquid separators. This requires rejection of solute-laden water ("blowdown" water). Energy can be lost as a result of warm blowdown water. This energy requirement can be offset by the fact that produced fluids in a mature SAGD operation are hot, allowing heat recovery from the produced fluids stream. This produced fluid heat recovery has been suggested to equal some 10–30% of the heat content of the steam.[11] Literature estimates for steam energy requirements vary: Charpentier cites up to 2.8 GJ/m^3 of steam, whereas Butler cites ≈3.4 GJ/m^3 for 100% quality steam generation with heat recovery.[14,15] Electricity consumption for in situ production has been estimated as 190 MJ/m^3 bitumen (8.25 kWh/bbl bitumen) but will vary with SOR due to dependence on pumping and separation loads.[5]

Steam generation for in situ production is generally fueled with natural gas. An exception is the OPTI-Nexen Long Lake project, which consumes gasified bitumen residues,[16,17] increasing GHG emissions compared with natural-gas-fueled SAGD.[17,18]

Bitumen Upgrading. Because contaminants are concentrated in heavy hydrocarbon fractions, bitumen has a high sulfur and metals content. In addition, bitumen is carbon-rich, hydrogen-deficient, and contains a larger fraction of asphaltenes than conventional crude oil. Thus, bitumen requires more intensive upgrading and refining than conventional crude oil.

Raw bitumen will not flow through a pipeline at ambient temperatures so it is upgraded to SCO or diluted with a light hydrocarbon diluent (creating "dilbit", or "synbit" if synthetic crude oil is used as the diluent) before transport. Diluent can be either returned to the processing site or included with bitumen to the refinery stream.

Greenhouse gas emissions from upgrading have three causes:

1 Combustion of fuels for process heat, including process gas, natural gas, and petroleum coke.
2 Hydrogen production using steam reformation of natural gas or, less commonly, from gasification of coke or bitumen residues.
3 Combustion for electricity generation (whether in cogeneration or off-site for from purchased electricity).

Upgrading bitumen to SCO is performed in two stages. Primary upgrading separates the bitumen into fractions and reduces the density of the resulting SCO. Secondary upgrading treats resulting SCO fractions to remove impurities such as sulfur, nitrogen, and metals.

Primary upgrading adjusts the H/C ratio by adding hydrogen or rejecting carbon from bitumen feedstock. The most common upgrading processes rely on fluid or delayed coking to reject carbon.[4,19,20] Coking generates upgraded oils as well as coke and process gas;[5] for example, Suncor's delayed coking upgrading resulted in 85% SCO, 9% process gas, and 6% coke by heating value.[21] Natural gas or coproduced process gas is often used to drive coking, but in a fluid coker, a portion of the coke is combusted to fuel the coking process. In existing operations, coke disposition varies: in 2009, Suncor combusted 26% of produced coke and exported another 7% for offsite use, and the rest was stockpiled or landfilled. In contrast, the CNRL Horizon project stockpiled all produced coke.[21]

A competing primary upgrading method uses hydrogen addition for primary upgrading. The Shell Scotford upgrader[22] uses an ebullating-bed catalytic hydrotreating process. Treating bitumen with hydrogen addition results in larger volumes of SCO produced from a given bitumen stream and a high-quality product. It also requires larger volumes of H_2, with associated natural gas consumption and GHG emissions. The Scotford upgrader produced 82% of process outputs as SCO, 18% as process gas, and no coke (on an energy content basis).[21]

In secondary upgrading, the heavier fractions of primary upgrading processes (which contain the majority of the contaminants) are hydrotreated (i.e., treated through the addition of H_2 in the presence of heat, pressure, and a catalyst). Light refinery-ready SCO of 30–34°API, 0.1 wt %

sulfur, and 500 ppm nitrogen is a common product.[23] Heavy SCO products, such as Suncor Synthetic H, are also produced, but in smaller quantities (≈20°API and sulfur content of ≈3 wt %).[24] In chemical composition, dilbit looks similar to heavy synthetic blends.

Hydrogen consumption by hydrotreaters is often in excess of 3 times the stoichiometric requirement for heteroatom removal because of simultaneous hydrogenation of unsaturated hydrocarbons.[23] Hydrogen consumed in secondary upgrading is generally produced via steam methane reformation of natural gas, regardless of primary upgrading process.[6] Current exceptions include the OPTI-Nexen integrated SAGD to SCO project, which gasifies bitumen residues for H_2 production. Consumption of H_2 in upgrading processes ranges from 1.2 to 3.1 GJ/m^3 of bitumen upgraded.[25]

Nearly all of the bitumen produced from mining is upgraded, while most of the in situ-based production is shipped as a bitumen/diluent mixture to refineries.[5] There is no fundamental physical or chemical reason that in situ-produced bitumen cannot be upgraded.[17]

SCO and Bitumen Refining. Nonupgraded bitumen supplied to refineries requires intensive refining because of quality deficiencies. Refining of bitumen also produces a less desirable slate of outputs without extensive processing as a result of high asphaltenes content. Light SCO is a high-value product with low sulfur content compared with conventional oils of similar density, because light SCOs lack the typical "bottoms" of a conventional crude oil (i.e., residual products from distillation). This is because components that would form the bottom of the distillation output profile are destroyed during upgrading.

Refining energy consumption is well correlated with the specific gravity and contaminant loading (e.g., sulfur) of input crude oil.[26,27] This is due to need for additional coking or additional hydrogen consumption, both of which are energy-intensive.

Noncombustion Process Emissions. Other process emissions include emissions from venting, flaring, and fugitive emissions (hereafter, VFF emissions). Environment Canada reported emissions of ∼3 g CO_2/MJ bitumen mined and in situ emissions of less than 1 g CO_2/MJ of bitumen produced.[28] Yeh et al.[29] found for mining operations that tailings ponds fugitive emissions had a wider range than fugitive emissions reported by Environment Canada, with a range of 0−8.7 g CO_2/MJ and a representative value of 2.3 g CO_2/MJ. It is not clear whether Environment Canada incorporates tailings pond emissions in these figures.

Land Use Change Associated Emissions. Land use change emissions are associated with biomass disturbance and oxidation due to land clearing, soil disturbance, and peat disturbance. These emissions are likely smaller than venting and fugitive emissions, with values ranging from 1.0 to 2.3 g CO_2/MJ of bitumen produced (representative value 1.4 g CO_2/MJ) for mining operations.[29] In a case that development is 100% on peatlands, land use emissions would increase by a factor of 3, suggesting that peat disturbance is a key driver of oil sands land use GHG emissions.[29] In situ operations have negligible land use emissions, ≈0.1 g CO_2 equiv/MJ of crude produced.

■ COMPARING PREVIOUS OIL SANDS LCA RESULTS

A number of LCAs of oil sands production have been performed, although none are yet comprehensive with detailed coverage of all oil sands production processes.[25,30,31] Over time, LCA studies have improved in quality and quantity of documentation, although gaps remain in the realm of publicly available models (see the Discussion and Recommendations section, below).

This paper reviews recent studies to determine the differences between study assumptions and to explore the uncertainty in resulting GHG emissions. The studies reviewed include

- **GREET**, the Greenhouse gases Regulated Emissions and Energy in Transportation model by Wang et al., Argonne National Laboratory;[32,33]
- **GHGenius**, the GHGenius model by O'Connor S&T[2] Consultants;.[34,35]
- **Jacobs**, a study by Keesom et al., Jacobs Consultancy;[25]
- **TIAX**, a study by Rosenfeld et al., TIAX LLC, and MathPro Inc.;[18]
- **NETL**, two studies by Gerdes and Skone, National Energy Technology Laboratory.[36,37]

A previous comprehensive comparison of oil sands GHG studies[6,19,38−41] was produced by Charpentier et al.[14] Other useful reviews are provided by Mui et al.[42,43] and by Hobbs et al., IHS-CERA Inc.[44] We will not attempt to recreate the analysis of these studies but in some cases use their results. One study reviewed but not included above is the Oil sands technology roadmap,[5] which is the source for GREET energy inputs to oil sands production.[45]

■ DIFFERENCES IN MODEL TREATMENT OF OIL SANDS PROCESSES

Determining the exact causes of differences between the results of reviewed models is impossible without access to original model calculations, but analysis of reported inputs and assumptions can give insight into reasons for divergence between estimates. These inputs can also suggest which model produces the most accurate estimates of project-specific or industry-wide emissions.

In all discussion below, energy content is reported on higher heating value basis (MJ or GJ HHV), and volumes are converted to cubic meters at standard conditions. Where required, volume- and mass-to-energy content conversions are made with fuel-specific compositions and relations between hydrocarbon density and chemical composition and heating values[46] (see the Supporting Information for calculation details).

System Boundaries and Study Scope. A main cause of variability between observed study results is the differences in broad methodological choices, such as study scope, system boundaries, and processes modeled (see Table 1).

A key difference between models is that some models assess emissions for an "average" oil-sands-derived fuel pathway, or generate industry averages (GREET, GHGenius, NETL), whereas others model emissions from specific oil sands projects (TIAX and Jacobs). This methodological difference overshadows many other sources of between-model variability.

The use of differing data sources of differing qualities is another major factor. As Charpentier et al. note, "the nature of the data used for the analysis varies significantly from theoretical literature values to project-specific material and energy balances".[14]

Another important difference is the study system boundary. Studies differ in the their treatment of indirect emissions (e.g.,

Table 1. Study Scope and System Boundaries by Reviewed Study

	scope of coverage	indirect emissions	embodied energy	venting, flaring, fugitives	land use
GREET	ind., pathway average	yes	no	yes	no
GHGenius	ind., pathway average	yes	no	yes	yes
Jacobs	process	NG + elec	no	no	no
TIAX	process	yes	no	yes	no
NETL	ind. average	yes	no	yes	no

emissions associated with producing natural gas consumed in upgrading operations), venting, flaring, and fugitive emissions as well as emissions from land use changes associated with oil sands mining. No study included emissions embodied in capital equipment (e.g., steel or cement upstream emissions).

Surface Mining. Emissions from mining are driven by the fuel consumed per unit of bitumen produced and the consumed fuel mix. In integrated operations, it is difficult to separate mining and upgrading inputs. Surface mining assumptions for each model are described below. The assumed fuel mixes and magnitudes of fuel consumption for mining and upgrading are shown by model in Figure 1. For comparison, industry reported

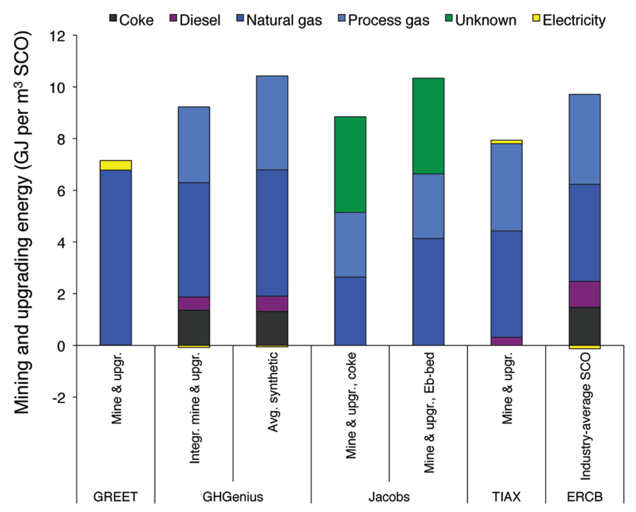

Figure 1. Fuel mix for mining and upgrading assumed by LCA models and industry average fuel mix (right). Fuel mix assumptions calculated from model inputs as described in text. Industry average fuel mix calculated from fuel consumption rates reported by ERCB for 2010 mining and upgrading operations.[47] See the Supporting Information for more detail on figure construction.

fuel consumption (from regulatory data provided by the Alberta Energy Resources Conservation Board, or ERCB) are plotted in the right-most column.[47]

GREET. Estimates for diesel use are derived from Alberta Chamber of Resources data, which includes 340 MJ of electricity (94 kWh), 1573 MJ of natural gas, and 9 MJ diesel used/m^3 of bitumen mined.[45] This low diesel use is a possible difference between GREET results and those of other oil sands LCAs.

GREET assumes no coke consumption, which is at odds with empirical fuel mixes presented in Figure 1 and other reports.[6,19] In addition, although GREET figures are based on ACR fuel use data, GREET emissions are 15.9 g CO_2/MJ refined fuel delivered, whereas ACR emissions results are ≈19−22 g CO_2/MJ. (These figures are only approximate comparisons because ACR data are measured in kg CO_2/bbl of SCO produced, and conversion factors to energetic units are not provided in ACR.[5] SCO density and heating value were set to values for 31°API oil to allow comparison.) This is likely due to the omission of coke combustion in the GREET model. Charpentier previously noted these discrepancies, stating that "the energy balance in GREET appears to omit the diesel fuel used in mining and the coke used in upgrading".[14]

GHGenius. Data include emissions from off-site power and hydrogen production[35] as well as on-site cogeneration. Standalone mining operations consume 1.35 GJ diesel/m^3 of bitumen produced, 2.78 GJ natural gas, and coproduce 250 MJ of electricity for export. The weighted fuel mix in GHGenius for mining and upgrading to synthetic crude assumes 15% of energy content from coke,[34] closely in line with observed industry average mining fuel mix (see Figure 1).

Jacobs. The surface mining process model is not described in detail. It is stated that the energy for mining is "one-half of energy needed for SAGD at an SOR of 3." This represents an energy cost of ≈3.7 GJ/m^3 of bitumen of unknown fuel mix. Process model represents an integrated operation fueled with natural gas and using either ebullating-bed hydrogen-based upgrading or coking (no coke combustion). It is therefore similar to the CNRL Horizon oil sands project.

TIAX. The model represents the CNRL Horizon mining and upgrading project, which consumes natural gas and stockpiles coke generated during upgrading.[18] Total consumption for mining and upgrading is ≈8 GJ/m^3 of SCO.

NETL. The model uses emissions reported by Syncrude for integrated mining and upgrading operation,[37] as reported in Environment Canada facilities emission database.[48]

The TIAX and GREET models assume lower energy consumption than the industry average, whereas the Jacobs and GHGenius models are in line with observed consumption values. The GHGenius model has the most accurate fuel mix assumption for an industry average. Because Jacobs and TIAX model a specific project (e.g., CNRL Horizon) that is natural-gas-fueled, they do not replicate the industry average fuel mix.

This importance of fuel mix on emissions has implications for future emissions. Some argue that future projects will rely on coke as much as or more than current operations, because of decreasing availability of low-cost natural gas,[17,19] and others believe that unconventional gas resources will allow low gas prices in the long term.

One complication in comparing these studies is uneven modeling of cogeneration of electric power. This shortcoming is likely to be a secondary source of uncertainty. For example, Suncor exported some 4.1 PJ of electric power in 2009, compared with electricity consumption of 7.5 PJ and total energy consumption of 137.1 PJ,[21] suggesting that credits or debits due to cogeneration will likely be a secondary source of variation.

Upgrading Emissions. Upgrading emissions are driven by the energy consumed per unit of SCO produced plus the fuel mix used in upgrading. Study assumptions regarding upgrading include

GREET. Consumption of natural gas is ≈3.3 GJ/m^3 SCO produced.[45] No consumption of coke or process gas is recorded, which differs from reported fuel mixes by operators.[47]

Upgrading consumption values are low compared with other estimates (e.g., Jacobs).

GHGenius. Imputed upgrading consumption in integrated mining and upgrading is 5.1 GJ/m^3, whereas stand-alone upgrading is much more energy-intensive at ≈9.8 GJ/m^3 SCO.[35] Fuel mix is included in Figure 1.

Jacobs. Consumption is ≈5.7 GJ/m^3 SCO for coking, and 7.4 GJ/m^3 SCO for Eb-bed. Fuel mix includes both natural gas and process gas. The fuel mix is ≈50% each natural gas and process gas for the coking unit, 60% natural gas and 40% process gas in Eb-bed reactor,[25] with no consumption of coke.

TIAX. The study does not report upgrading consumption separately from mining or SAGD consumption. Integrated operations are modeled, and process flows are not delineated by mining and upgrading stages.[18]

NETL. A separate description of upgrading is not given in NETL studies.[36,37] Upgrading emissions are included in emissions from Syncrude integrating mining and upgrading operation, as described above.

Differences in emissions between Jacobs and GHGenius estimates are likely due to fuel mix differences, due to the similar energy consumption values. Given observed consumption of coke (see ERCB data in Figure 1), GHGenius estimates are more representative of industry-wide upgrading emissions. GHG-intensive upgrading using bitumen residues at OPTI-Nexen Long Lake project is neglected in all models except TIAX, but this is a relatively small operation, and therefore, this will not strongly affect model results in other models.

In Situ Production. Because of relatively homogeneous fuel mix consumed for in situ production, the primary determinants of emissions are the SOR and the energy consumed per unit of steam produced. In some studies, the product of these two terms—the energy consumed per volume of crude bitumen produced—is reported. Model assumptions include

GREET. Natural gas consumption is ~6.8 GJ/m^3 bitumen.[45] Because no SOR is reported, the energy consumed per cubic meter of steam cannot be calculated.

GHGenius. SORs of 3.2 and 3.4 assumed for SAGD and CSS, respectively.[14,49] Natural gas consumption is 9.6 and 10.2 GJ/m^3 of bitumen produced for CSS and SAGD, respectively.

Jacobs. Jacobs assumes SORs of 3.[25] Energy content of steam is 2.06 GJ/m^3 CWE steam, and efficiency is 85% (LHV basis), for total consumption of ≈8.1 GJ LHV/m^3 bitumen. Cogeneration of electric power provides an emissions offset in some cases.[25] Because SAGD net cogeneration exports are not reported in ERCB data sets, electricity exports cannot be verified using reported industry data.[22]

TIAX. Natural gas consumption rates are at the low end of the above cited range, 4.1 and 7.8 GJ/m^3 bitumen for Christina Lake (SAGD) and Cold Lake (CSS) respectively (without cogeneration).[18] The Christina Lake SAGD case has an SOR of 2.5 and a low implied energy consumption of 1.7 GJ/m^3 CWE of steam. These values are lower than the empirical values shown below, driving the low emissions from the TIAX natural gas case. Cases with cogeneration have somewhat higher effective steam energy requirements (see the Supporting Information). TIAX is the only report to consider integrated in situ production with bitumen residue or coke fueling. The TIAX case with asphaltenes residue gasification for steam generation (analogous to OPTI-Nexen Long Lake project) has a higher energy demand of 5.4 GJ/m^3 of steam generated, resulting in much higher emissions, as should be expected from the carbon intensity of asphaltene residue gasification.[18]

NETL. Emissions calculated for Imperial Oil Cold Lake project using CSS,[37] as reported in the Environment Canada facilities emission database.[48] In 2009, Cold Lake had an SOR of 3.5.[21]

The energy intensity of steam generation for the reviewed studies can be compared with calculated values from engineering fundamentals and values reported in the literature. These comparisons are shown in Figure 2. At top are fundamental

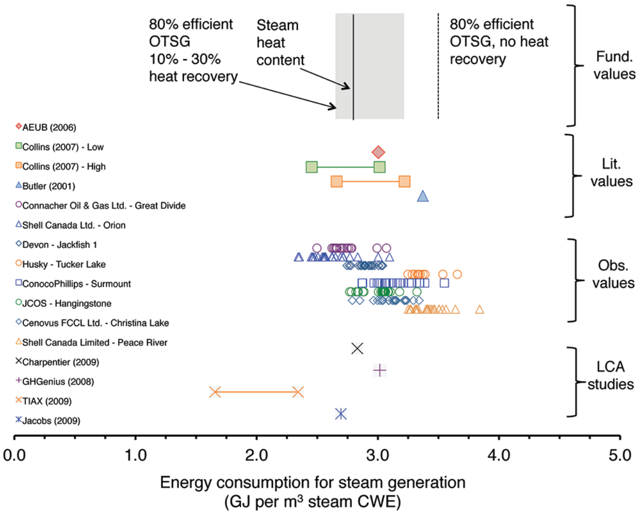

Figure 2. Assumed energy intensity of steam generation for studies and values from literature. Lines and shaded areas represent the energy content of the steam at typical SAGD conditions[11] (solid), the energy cost of obtaining this steam with an 80% efficient OTSG and complete heat recovery from blowdown water (dashed), and the energy cost with 80% efficient OTSG and heat recovery of 10−30% of the enthalpy of steam from warm produced fluids (shaded). Values are from the literature from various sources.[11,15,50]

computations of energy requirements, including the steam enthalpy at typical SAGD conditions (100% quality steam at 2000 kPa, or $h_g \approx 2.8$ GJ/m^3)[11] and the required energy consumption for steam generation, assuming no heat recovery from produced fluids. Also shown is a consumption band assuming 10−30% heat recovery from produced fluids. Next, estimates from the literature are presented, which are generally in line with fundamental values. Next, monthly energy intensities for 8 in situ projects are calculated from the reported literature. Last, assumptions for energy consumption in steam generation are shown for reviewed LCA models. A key result is that TIAX values are significantly lower than values from the literature. See the Supporting Information for figure construction details.

In addition, the SORs assumed can be compared with SORs observed in practice, as in Figure 3. The SOR histogram shows SORs by fraction of industry output from reported data, as well as averages by process type (top axis). GHGenius and NETL report SORs in line with observed SORs, whereas the TIAX SAGD case is toward the low end of observed SORs.

Refining Emissions. Many LCA studies to date treat the refining of crude inputs (SCO and bitumen) in a simple fashion.[32,51] This is partly due to the absence of publicly available models of refinery operations and due to the fact that some models (such as GREET) have sought to produce a national average result, without modeling refining differences between individual crude oils.

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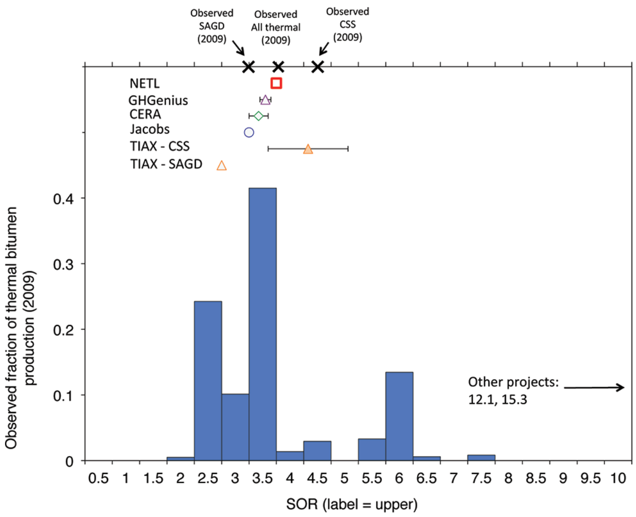

Figure 3. Assumed SORs for each model compared with observed SORs from ERCB data. Top marks represent production-weighted average for CSS and SAGD operations and 2009 full-year production volumes.

Refinery feedstock qualities differ by study, as shown in the Supporting Information. Some studies do not state explicitly the quality of refinery feedstock. SCO characteristics from studies align well with the reported characteristics of commercial SCO products. The resulting estimates of refining emissions as a function of crude specific gravity are plotted in Figure 4.

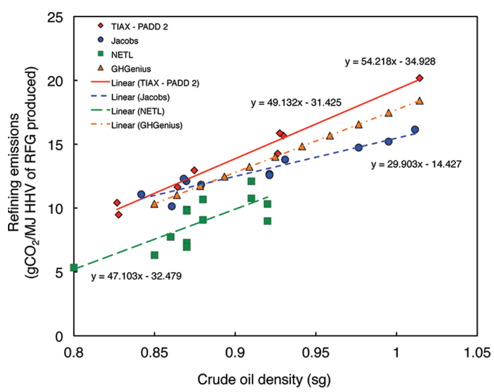

Figure 4. Refining emissions as a function of crude specific gravity for oil sands GHG emissions study. For TIAX, Jacobs, and NETL, the sulfur content varies with crude type. For GHGenius results, model version 3.20 was used with 2 wt % sulfur content for all crude oils.

GREET. The model calculates refinery emissions from processing oil-sands-derived streams as equivalent to processing conventional crude oil streams.[45,40] This assumption will not result in significant errors because GREET assumes bitumen is upgraded to SCO.[40]

GHGenius. The model relies (as of version 3.20) on a linear model of refinery emissions as a function of API gravity and sulfur, derived from Karras.[26] The relationship between sulfur and emissions is from Karras, and the slope of energy consumed as a function of density is set to one-half the Karras value.[34]

Jacobs. Detailed calculation of refinery inputs and outputs with refining simulation software. Results from the commercial refinery process model are presented in detail, with process throughputs and products breakdown provided for SCO, bitumen, and dilbit.[25] Detailed refining utilities consumption by subprocess is presented for Arab Medium crude, but not for oil sands pathways.[25]

TIAX. The model performs a detailed calculation of refinery inputs and outputs, using industry refinery modeling expertise, with extensive documentation. Model results include differential refining emissions based on the quality of the feedstock.[18]

NETL. The approach used by Gerdes et al.[36] is outlined in detail in Skone et al.[37] A novel approach is developed using US nationwide statistical data on refinery configurations, crude throughputs, crude qualities, and utilization factors for different crude processing stages (e.g., distillation utilized capacity vs fluid catalytic cracking utilized capacity). This approach is similar to that taken by Karras.[26] Heuristic models for the effect of crude density and sulfur content on refining intensity are developed.[36]

The Jacobs and TIAX models represent the most thorough efforts to date to model refinery emissions for refining oil-sands-derived fuels. The NETL model represents the most thorough treatment of the problem using public data. Given the relative similarity of refinery emissions model results, it is not clear that enough empirical data exists about refinery emissions to assess the relative merits of the different models. One concern in refinery modeling is that the different quality of SCO as compared with conventional oil will change refinery output slates, possibly indirectly affecting emissions in other sectors (see Discussion and Recommendations, below). In addition, a number of parameters not included in current simple refining models could be causing discrepancies between different model results (for example, Jacobs notes sensitivity to refinery configuration, which is not included in simpler models).

Other Process Emissions. Emissions from venting, fugitive emissions, and flaring (VFF) are unevenly addressed in the above studies. GREET does not include VFF emissions from bitumen extraction or upgrading.[40] GHGenius does include venting and flaring emissions.[34] Jacobs does not explicitly include VFF emissions from oil sands production.[25] TIAX does include VFF emissions, of 0.5 to 3.3 g CO_2 equiv/MJ[18] from regulatory documents related to the Horizon oil sands mine. NETL does include venting and flaring,[36] but does not describe method for estimating bitumen VFF emissions.

Land use emissions are considered only in the GHGenius model, which calculates soil and biomass disturbance per hectare and apportions this according to the type of operation (e.g., 100% disturbance on mined lands, no disturbance for SAGD).[35]

Resulting GHG Emissions Estimates. The resulting upstream GHG emissions estimates by study are shown in Figure 5. For simplicity, vehicular emissions (tank-to-wheel) emissions are given a nominal value of 70 g CO_2/MJ in all cases (TTW results are largely consistent across models and are not a focus of this study). A detailed breakdown of emissions for each data point is given in the Supporting Information.

General trends emerge among pathways as a result of the underlying fundamentals of process operation. In situ and upgrading projects have higher emissions, as should be expected from projects that combine energy-intensive extraction methods with energy-intensive upgrading.

Variability between estimates from a given study arise from varying process assumptions. For example, the four TIAX results for in situ-to-bitumen pathways differ in their

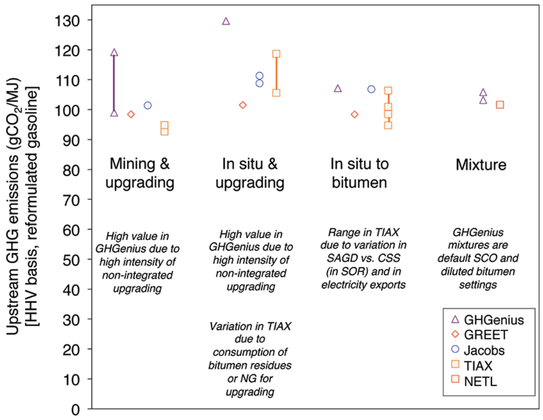

Figure 5. Full-fuel-cycle GHG emissions estimates for reformulated gasoline pathways by study. Nominal value of 70 g CO_2/MJ for combustion emissions is applied evenly across all studies. Details on construction of th estimates are given in the Supporting Information.

assumptions about the method of extraction used (i.e., SAGD vs CSS) and in whether they export cogenerated electric power. Clearly, emissions will vary between among implementations of similar pathways.

In general, GREET and TIAX model results are at the lower end of the emissions range. This should be expected from their assumptions about the energy intensity of extraction, as shown above for mining and in situ production.

In addition, in general, the GHGenius model tends to have somewhat higher emissions than other studies. A driver of these higher emissions is due to more careful accounting of energy consumption in GHGenius and due to industry-average fuel mixes that contain coke combustion. Some additional research is needed with respect to GHGenius stand-alone upgrading emissions, which are assigned a high emissions intensity. This does not strongly affect the overall results from GHGenius (as plotted in Figure 5 in the "mixture" column as default SCO and default bitumen pathways) because stand-alone upgrading is not a major pathway in current operations. In general, given the fidelity of GHGenius in replicating energy inputs to mining and in situ processes, GHGenius emissions estimates should not be considered overly pessimistic.

■ DISCUSSION AND RECOMMENDATIONS

Recommended Use of Model Results. The GHGenius model is recommended for use in generating industry-average GHG emissions values, such as those that might be required to assign default values in regulation. GHGenius contains the most accurate representation of observed energy consumption values for the industry as a whole, as seen in Figure 1 for surface mining and upgrading operations, in Figure 2 for steam energy content, and in Figure 3 for steam/oil ratios. It also includes emissions sources such as VFF and land use emissions that are not covered consistently by other models. In addition, its transparent and extensive documentation is a useful contribution to the literature and allows for fact checking of inputs.

Although the GREET model is publicly available and treats industry average pathways, its use for constructing industry-average emissions is not recommended because of less accurate energy intensity and fuel mix assumptions compared with GHGenius.

The Jacobs and TIAX models represent more detailed LCA studies of project-specific emissions. They provided important advances in refinery models compared with earlier studies. These estimates are useful for understanding specific pathways, but should not be considered representative of industry-wide emissions averages because of their focus on specific projects that may not be representative of general industry conditions.

Comparability of Studies. Figure 5 shows the considerable variation among model results for different processes and even significant variation within similar pathways. The key factor affecting the comparability of studies is whether study results are process-specific or pathway or industry-average emissions estimates. Process-specific emissions estimates and industry-average emissions estimates are useful in different contexts.

For regulatory purposes for determining the potential overall scale of differences in emissions among broad fuel types (e.g., conventional oil and oil sands), industry-wide production-weighted average emissions are more useful than process-specific assessments. For evaluating the GHG intensity of a given process or a given import stream, process-specific emissions estimates are required.

Other factors affecting the comparability of models include the study system boundaries. In the studied LCA models, study system boundaries are broadly commensurate (e.g., all are well-to-wheel LCA analyses), although smaller system boundary considerations were noted above, such as the inclusion or exclusion of land use emissions.

Uncertainties and Need for Future Work. A number of uncertainties remain in the area of oil sands GHG emissions. Treatment of cogenerated electric power varies among models. Given the CO_2 intensity of the Alberta grid, coproduction credits from cogenerated power could be provide emissions offsets. Important future research needs for electricity credits include variation with time, place, and characteristics of Alberta grid in relation to interconnected grids.

Treatment of refining is a difficulty in public-domain studies such as GREET and GHGenius because of a lack of access to industry-vetted refinery models. The Jacobs and TIAX refining models represent the most detailed work to date on refining emissions (although their models are not publicly available). The previous lack of data on refining emissions has been remedied somewhat recently, with increasing public access to correlations between emissions and crude density and sulfur content,[26] but additional work is needed. Importantly, refinery emissions vary with refinery configuration, the type of oil sands product refined (i.e., SCO, dilbit or synbit), and the refinery output slate.

Numerous coproduction issues arise that are not incorporated consistently in current studies. For example, the treatment of coproduced coke is a complex issue. This is noted in the Jacobs study but not treated elsewhere. At remote Alberta upgrading facilities, coproduced coke is generally stockpiled or burned on site to fuel operations. If bitumen is shipped to refineries as dilbit, this will result in coke generation near existing fuels markets, which could result in more coke being consumed, offsetting some coal consumption. Calculating the magnitude of credit or debit associated with such coproduction and displacement is nontrivial and requires understanding of the markets for solid fuels. Similar concerns arise with the treatment of diluent in dilbit pathways.

The interaction of oil sands products with existing fuel production systems and fuel demands is still poorly understood. For example, refinery outputs from refining a light SCO product will differ from outputs from a crude oil input of similar specific gravity and sulfur content (more middle distillate and less residual fuel from SCO). This could have ripple effects on other fuels markets and alter the energy requirements of producing a given refinery mix (e.g., EU refineries might not face as large an energy penalty associated with producing diesel-heavy refinery product slate).

The interaction of markets in LCA (as addressed in "consequential" LCA) is not studied in detail in any of the above models. Given a regulation that reduced the demand for oil sands products in North America (such as an expansion of the California LCFS to the national scale), there could be shifts in shipment of liquid fuels in the global fuels market (also known as crude shuffling). This shift of fuels could offset some of the desired reduction in emissions. The calculation of such impacts would require a combination of fuel market models with detailed LCA models. This is a difficult problem and likely subject to significant uncertainty.

Future work in oil sands GHG emissions should move toward modeling the emissions of specific process configurations. For example, models should be used to model emissions by project and compare those modeled emissions to reported emissions estimates. More vigorous calibration with available data (such as ERCB reported data sets) will help verify model accuracy. Much of the variability seen in the results above is driven by fundamental differences between different process operations (e.g., fuel mix or steam generation efficiency variation between project). Without more transparency and clarity about which processes are being modeled (and how representative they are of industry-wide operations), additional confusion will be introduced into assessing the environmental impacts of oil sands production.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Additional results, including tabular results for important results figures. This material is available free of charge via the Internet at http://pubs.acs.org.

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