Oil Sands Energy Intensity Analysis for GREET Model Update

Technical Documentation

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Contents

Contents (Cont.)

Figures

Tables

1 Introduction

The Alberta oil sands have become a significant supplier of liquid fuels in the last decade. In 2010, production of crude bitumen from the oil sands reached 1.17×10^7 GJ/d (1.76 Mbbl/d), or approximately 2% of world oil production. Some projections forecast production of 3.6×10^7 GJ/d (5.33 Mbbl/d) of bitumen by 2030 (*Oil and Gas Journal* 2012).

A challenge for oil-sands-derived fuels is that their full fuel cycle (also known as well-to-wheels or WTW) greenhouse gas (GHG) intensity is higher than the intensity of the fuels that are derived from most conventional crude oil feedstocks. Increased emissions result from the carbon-rich, hydrogen-deficient nature of the bitumen feedstock. These characteristics increase the energy required to extract, separate, and process bitumen. In addition, the extraction of oil sands results in secondary sources of emissions (e.g., fugitive emissions, emissions from land use impacts, methane emissions from tailings ponds). Regulations such as the California Low Carbon Fuel Standard (LCFS) and the European Union Fuel Quality Directive (FQD) have focused attention on the intensity of oil sands emissions (CARB 2011; European Parliament and the Council of the European Union 2009; Brandt 2011).

GREET v. 1_2012 (previous to this update) aggregates oil sands production into surface mining and in situ pathways. It provides fuel shares for energy consumption during different phases of operation, including bitumen extraction, upgrading, transportation to refineries, and storage. However, the underlying data on oil sands operations are out of date, and the reported fuel shares are not representative of current practices. For example, energy consumption for mining and in situ production is modeled as a mixture of electricity and natural gas. In addition, products derived from heavy oil sands (e.g., synbit) require relatively more energy inputs during refining. This differentiation of refining energy intensities was not able to be modeled in the previous treatment of oil sands in GREET.

In this report, we have developed an analysis that can improve oil sands modeling in GREET in multiple ways. It can:

- Increase the fidelity of oil sands modeling by defining four production pathways rather than the two pathways implemented in GREET v. 1_2012;
- Use publicly available data to generate detailed estimates of energy intensity, fuel shares, flaring, and fugitive emission rates from oil sands operations; and
- Incorporate uncertainty into analyzed pathways, including month-to-month variability in energy requirements in oil sands extraction and upgrading.

2 Methods

Hydrocarbons can be extracted from oil sands in three ways: surface mining, thermal in situ production, and primary production. Reservoirs within 50 m of the surface are typically mined using shovel and truck extraction methods. Deeper reservoirs are extracted primarily through thermal recovery (in situ) methods. These include cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). CSS uses one vertical well in which steam is injected for a period and from which bitumen is subsequently produced. SAGD uses two horizontal wells; steam is injected into the top well to warm the bitumen, which reduces its viscosity and allows it to flow by gravity to the lower horizontal well, where it is drawn to the surface. A smaller fraction is extracted through primary production (also known as cold production) methods. After bitumen is extracted, there are multiple pathways by which it is refined into products. The most important pathways are the upgrading of bitumen to pipeline-ready synthetic crude oil (SCO) and the mixing of bitumen with diluent so that it can flow to refineries for processing.

2.1 Study time period and project inclusion

This study time period is 2005 through 2012 for the mining projects and 2009 through 2012 for in situ projects. These time periods were chosen in order to balance the need for an assessment of the variabilities of the projects over time with the need for a sufficient amount of data. Although there have been significant changes within the industry over the longer term (as shown in recent literature), there has been less change in the energy intensity of extraction over the past decade (Englander et al. 2013). The study time period is shorter for in situ projects because complete datasets for in situ production only became available in 2009.

The study includes 24 projects that are classified as either mining projects or thermal in situ projects. It includes all projects that were producing commercial quantities of bitumen during the study period. Primary production, in which higher-quality heavy oil is extracted by using technologies such as cold heavy oil production with sand (CHOPS), is not included in this update because no data on energy consumption have been reported for these projects. We reviewed Alberta Energy Regulator (AER, formerly Energy Resources Conservation Board [ERCB]) documents from 1993 through 2012. Table 1 lists the 24 projects (Nexen is in two spots) with their 2012 production volumes.

Table 1 List of included projects and 2012 production volumes (primary bitumen extraction)

Operator	Project	In-Text Reference	Production (kbbl/d)[a]
Mining and SCO Projects			
Suncor	Millenium, Steepbank, and Voyageur (MSV)	Suncor-MSV	267
Syncrude	Mildred Lake	Syncrude-Mildred Lake	152
Syncrude	Aurora	Syncrude-Aurora	184
Albian Sands	Muskeg River Mine	Albian Sands-Muskeg River	129
Shell	Scotford Upgrader	Shell-Scotford	b
Shell	Jackpine Mine	Shell-Jackpine	97
Nexen	Long Lake	Nexen-Long Lake	c
Canadian Natural Resources Ltd. (CNRL)	Horizon	CNRL-Horizon	103
In Situ Projects			
Shell	Peace River	Shell-Peace River	6
Imperial	Cold Lake	Imperial-Cold Lake	138
Cenovus FCCL	Christina Lake	Cenovus-Christina Lake	26
Cenovus FCCL	Foster Creek	Cenovus-Foster Creek	104
Suncor	MacKay River	Suncor-MacKay River	24
Japan Canada Oil Sands (JACOS)	Hangingstone	JACOS-Hangingstone	5
Suncor	Firebag	Suncor-Firebag	94
CNRL	Primrose and Wolf Lake	CNRL-Primrose and Wolf Lake	88
ConocoPhillips Canada	Surmont	Conoco-Surmont	20
Nexen[c]	Long Lake	Nexen-Long Lake	28
Husky	Tucker Lake	Husky-Tucker	9
Devon NEC	Jackfish 1	Devon-Jackfish	45
Shell	Orion	Shell-Orion	4
Connacher	Great Divide	Connacher-Great Divide	7
MEG Energy	Christina Lake	MEG-Christina Lake	26
Statoil Canada	Leismer	Statoil-Leismer	15
Connacher	Algar	Connacher-Algar	4

[a] Production of primary bitumen in 2012 are in units of 1,000 barrels per day. Delivered volumes of product (e.g., SCO or diluted-bitumen) will differ by project.

[b] Shell-Scotford is an upgrader connected to the Albian Sands-Muskeg River and Shell-Jackpine mines, but it does not produce any bitumen

[c] The Nexen-Long Lake project is included in both the mining and in situ datasets because it pairs a surface upgrader with an in situ operation. Data on surface upgrading operations are reported in the mining dataset, while data on subsurface operations (e.g., steam-oil ratios) are reported in in situ datasets.

2.2 System boundary and functional unit

A life cycle analysis (LCA) system boundary delineates which processes and impacts are included within an LCA model. Because this analysis is designed to provide input parameters for the GREET oil sands module, our system boundary includes direct consumption of all primary fuels and electricity at production sites. We include emissions associated with tailings ponds and also fugitive emissions associated with crude bitumen batteries from in situ production.

The emissions that are included in this update but are not included in this report are those resulting from direct land use change. The Yeh et al. (2010) report documents those emission sources. The system boundary for this report does not include off-site emissions associated with generating electricity or producing natural gas. However, Alberta-specific electricity intensities as well as upstream natural gas emissions values will be incorporated in the GREET model, so these indirect emissions will be taken into account. Our system boundary does not include emissions embodied in capital equipment, such as wells, trucks, or upgraders. Schematics of the mining plus SCO (M+SCO) and in situ plus bitumen (IS+Bit) system boundaries are given in Figure 1 and Figure 2, respectively.

The functional unit of this analysis is 1 GJ of hydrocarbon output at the project output gate (i.e., before transport to a refinery). All results are presented on a lower heating value (LHV) basis. Depending on the pathway being modeled, the hydrocarbon output can be in the form of SCO or bitumen. Our results are presented as GJ of energy consumed per GJ functional unit [GJ consumed/GJ output]. These results can be readily converted into GREET process efficiencies and fuel shares.

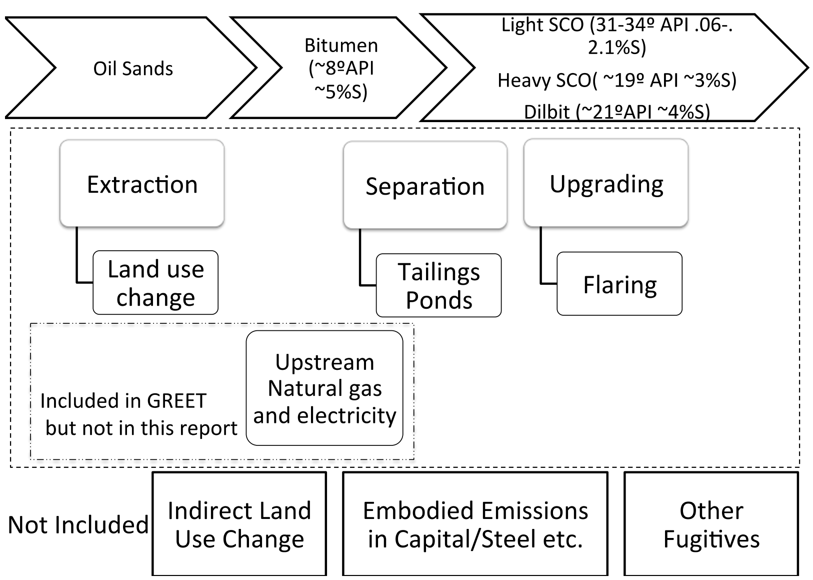

Figure 1 System boundary for M+SCO pathways

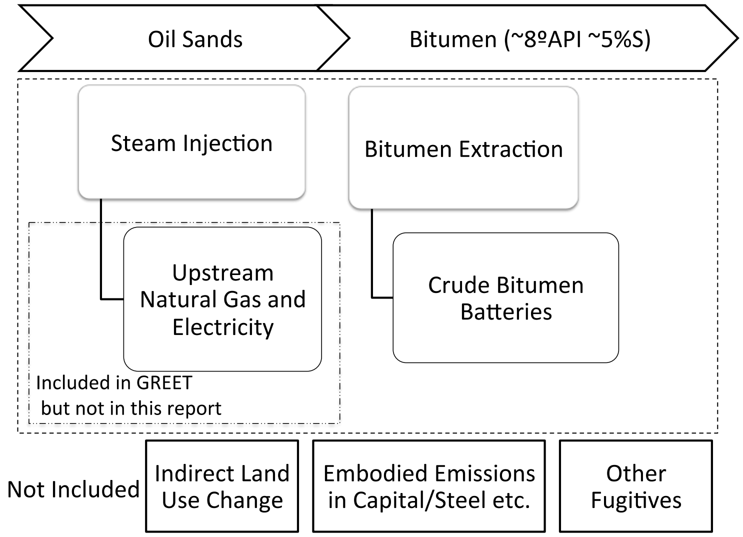

Figure 2 System boundary for IS+Bit pathways

2.3 Pathway definitions

A first-order approximation frequently used in the scientific literature is to categorize production processes either as mining plus upgrading or as in situ plus dilution. In other words, all mining processes are assumed to produce SCO, and in situ processes are assumed to produce dilbit (bitumen thinned by an added diluent, typically natural gas condensate) [(S&T)^2 2011b; Forrest et al. 2012; Argonne National Laboratory 2012; Yeh et al. 2010].

This is a useful approximation, since these are the most historically prevalent pathways. However, as refineries have become better able to accept bitumen as either dilbit or synbit (bitumen mixed with diluent or bitumen mixed with SCO), this first-order approximation breaks down. In 2012, 7% of products sent from upgraders were either dilbit or synbit, and there were in situ projects that sent their products to upgraders (e.g., Suncor-Firebag) or were integrated with surface upgrading facilities (e.g., Nexen-Long Lake).

Because of the complexity of oil sands production practices, numerous pathway definitions could be developed. For this study, we examined four options for aggregating projects into pathways:

1. Pathway Option 1: All oil sands projects are aggregated into a single industry-average pathway.

2. Pathway Option 2: Projects are aggregated on the basis of production method, creating mining and in situ pathways.

3. Pathway Option 3: Projects are aggregated on the basis of both production method (e.g., mining or in situ) and output product (e.g., SCO or dilbit).

4. Pathway Option 4: Each project is modeled individually.

For use in GREET, we determined that Pathway Option 3 is the most feasible. Pathway Options 1 and 2 do not contain enough fidelity to appropriately model oil sands processes and products. A discussion of Pathway Options 1 and 2 is provided in Appendix A. In contrast, Pathway Option 4 would result in a proliferation of pathways, which would require a much greater modeling effort for what would likely be only a small increase in fidelity. For this reason, Pathway Option 4 is not discussed further.

The chosen method, Pathway Option 3, aggregates projects by both production method (mining or in situ) and output product (SCO or diluted bitumen). This aggregation results in four pathways. Modeling production using four pathways results in increased fidelity because each pathway produces more uniform products (e.g., projects that produce diluted bitumen are classified together). This allows increased accuracy when accounting for refinery energy use as a function of refinery input product, given differences in refinery requirements for SCO and dilbit refining.

Modeling methods for each pathway are described here. The assignment of each project into one (or more) of the four pathways is shown in Table 2.

First, we compute output-fuel-specific fuel shares for a given project:

$$FS_{fp,SCO} = \frac{F_{fp}}{P_p^{SCO}} \qquad \left[\frac{\text{MJ fuel}}{\text{MJ SCO}}\right] \qquad \text{(eq. 1)}$$

$$FS_{fp,Bit} = \frac{F_{fp}}{P_p^{Bit}} \qquad \left[\frac{\text{MJ fuel}}{\text{MJ bitumen}}\right] \qquad \text{(eq. 2)}$$

where *F* is process fuel consumed, *P* is the amount of output product produced, *f* is the index of fuel types consumed, *p* is the index of projects, and *SCO* or *Bit* is the output product produced. These project-specific fuel shares are then used to generate pathway-specific weighted fuel shares, accounting for both production technology and output product. These four pathways are defined as:

1. Mining plus SCO (M+SCO), producing SCO;

2. Mining plus bitumen (M+Bit), producing diluted bitumen (dilbit and synbit);

3. In situ plus SCO (IS+SCO), producing SCO; and

4. In situ plus bitumen (IS+Bit), producing diluted bitumen (dilbit, synbit, or dil-synbit).

Table 2 Pathway specifications of included projects

Project	Notes
M+SCO Projects	
Suncor-MSV	
Syncrude-Mildred Lake	
Syncrude-Aurora	
Albian Sands-Muskeg River	
Shell-Scotford	
Shell-Jackpine	
CNRL-Horizon	
M+Bit Projects	
Syncrude-Aurora	Also used to estimate upgrading energy use for the IS+SCO pathway. See Section 2.3.4 for details.
Albian Sands-Muskeg River	This project exports dilbit to an upgrader.
Shell-Jackpine	See note for Albian Sands-Muskeg River.
IS+Bit Projects	
Shell-Peace River	
Imperial-Cold Lake	
Cenovus-Christina Lake	
Cenovus-Foster Creek	
Suncor-MacKay River	
JACOS-Hangingstone	
CNRL-Primrose and Wolf Lake	
Conoco-Surmont	
Husky-Tucker	
Devon- Jackfish	
Shell-Orion	
Connacher-Great Divide	
MEG-Christina Lake	
Statoil-Leismer	
Connacher-Algar	
IS+SCO Projects	
Suncor-Firebag	See Section 2.3.4 for notes on nonintegrated upgrading requirements.
Nexen-Long Lake	Integrated upgrader: no estimation of upgrading is required.

In reality, some variation exists between output products produced at a given project (e.g., varying grades of SCO or varying synbit products) and across projects within a pathway. The uncertainty associated with this variability is discussed below.

2.3.1 Mining Plus SCO

Approximately 90% of oil sands production is produced by either the M+SCO or IS+Bit pathway. These pathways are the most simple to define. In both cases, pathway fuel shares can be calculated by taking production-weighted averages for each of the fuel input types across projects. In the case of the M+SCO pathway, upgraders can produce SCO via delayed coking, fluid coking, and hydrocracking. Therefore, the resulting fuel shares for M+SCO represent an aggregation of these different technologies in proportion to their production volume.

Equation 3 shows this production-weighted average fuel share calculation for the M+SCO pathway:

$$FS_{f,M+SCO} = \sum_{p\in M+SCO} FS_{fp,SCO}\left(\frac{P_p^{SCO}}{\sum_{p\in M+SCO} P_p^{SCO}}\right) \quad \left[\frac{\text{MJ fuel}}{\text{MJ SCO}}\right] \qquad \text{(eq. 3)}$$

Note that project-level fuel shares are weighted by SCO output, since this is the primary output of the M+SCO pathway.

2.3.2 In Situ Plus Bitumen

The IS+Bit pathway is modeled similarly to the M+SCO pathway:

$$FS_{f,IS+Bit} = \sum_{p\in IS+Bit} FS_{fp,Bit}\left(\frac{P_p^{Bit}}{\sum_{p\in M+SCO} P_p^{Bit}}\right) \quad \left[\frac{\text{MJ fuel}}{\text{MJ Bitumen}}\right] \qquad \text{(eq. 4)}$$

Note that the project-level fuel shares are weighted by bitumen output, since this is the primary output of the IS+Bit pathway. We do not include the volume of diluent in this weighting term. The volume of diluent blended with the raw bitumen will vary, depending on the project and the grade of desired quality output. For this reason, we chose to simply weight the contribution of the projects by their contribution of primary bitumen produced.

2.3.3 Mining Plus Bitumen

Bitumen is exported as a minor product from the Suncor-MSV mining project as well as from the Shell-Scotford upgrader. The source of this exported bitumen is not recorded in production statistics, except as an overall output from the upgrading facility. It is therefore unclear whether the bitumen exported directly from Suncor-MSV has a different origin than does the bitumen that is upgraded to SCO.

When AER reports data on energy use for integrated mining and upgrading facilities, it does not distinguish between energy use for mining and that for upgrading processes (ERCB ST39).[1]

[1] Because of heat and power integration between mining and upgrading operations, it is not clear if a rigorous distinction could be made in practice.

Instead, we model the mining portion of the M+Bit pathway by using consumption data from nonintegrated, standalone mines. These mines include the Albian Sands-Muskeg River Mine, Shell-Jackpine Mine, and Syncrude-Aurora Mine. A similar approach is used in the GHGenius model [(S&T)[2] 2011b]. While these projects do not export bitumen directly to the market in significant quantities, they are the best proxy for mining energy use in a standalone M+Bit pathway. As more data become available (e.g., from the Imperial-Kearl Mine), greater fidelity in modeling this pathway will become possible. Equation 5 illustrates the calculation of energy use in this pathway:

$$FS_{f,M+Bit} = \sum_{p \in M+Bit} FS_{fp,Bit} \left(\frac{P_p^{Bit}}{\sum_{p \in M+Bit} P_p^{Bit}} \right) \quad \left[\frac{\text{MJ fuel}}{\text{MJ Bitumen}} \right] \qquad \text{(eq. 5)}$$

Because of data reporting gaps, some complexity emerges in using this equation. Natural gas and electricity use are reported at all three included mines, so the equation can be used directly for these fuel shares. However, both the Albian Sands-Muskeg River and Shell-Jackpine facilities do not report input SCO or diesel (henceforth referred to as diesel) use for truck fuel, although they do consume such fuel. To model the diesel consumed (which is recorded at all of the other mining projects), we defined a fuel share for GJ diesel/GJ bitumen produced as the average of the diesel fuel share intensity of Suncor-MSV and Syncrude-Mildred Lake and Aurora. A plot of the fuel shares for both Suncor-MSV and Syncrude-Mildred Lake and Aurora is provided in Figure 3.

2.3.4 In Situ Plus SCO

In situ produced bitumen is upgraded to SCO in a limited number of cases.[2] Bitumen from the Suncor-Firebag project is upgraded at the Suncor-MSV upgrader, and the integrated Nexen-Long Lake project produces upgraded SCO on site by using the byproducts from upgrading to fuel steam generation for in situ recovery. Nexen-Long Lake energy use is reported directly in AER statistics. In contrast, the Suncor-MSV facility statistics do not distinguish between energy used in the mine and the upgrader (see previous discussion). To approximate the requirements of upgrading at Suncor-MSV, the following two steps were performed to remove the mining portion of fuels consumed for the Suncor-MSV integrated mine and upgrader:

1. The Suncor-MSV fuel share for SCO/diesel was removed, since this is known to be used in mining trucks.

2. For natural gas and electricity, the fuel intensity per unit of bitumen produced from the Syncrude-Aurora Mine is used to adjust the energy intensity of the combined

[2] Many diluted bitumen pathways include an upgrading step before refining. However, it is assumed that the energy use associated with those emissions is accounted for in the refining stage, and it is not included in this analysis.

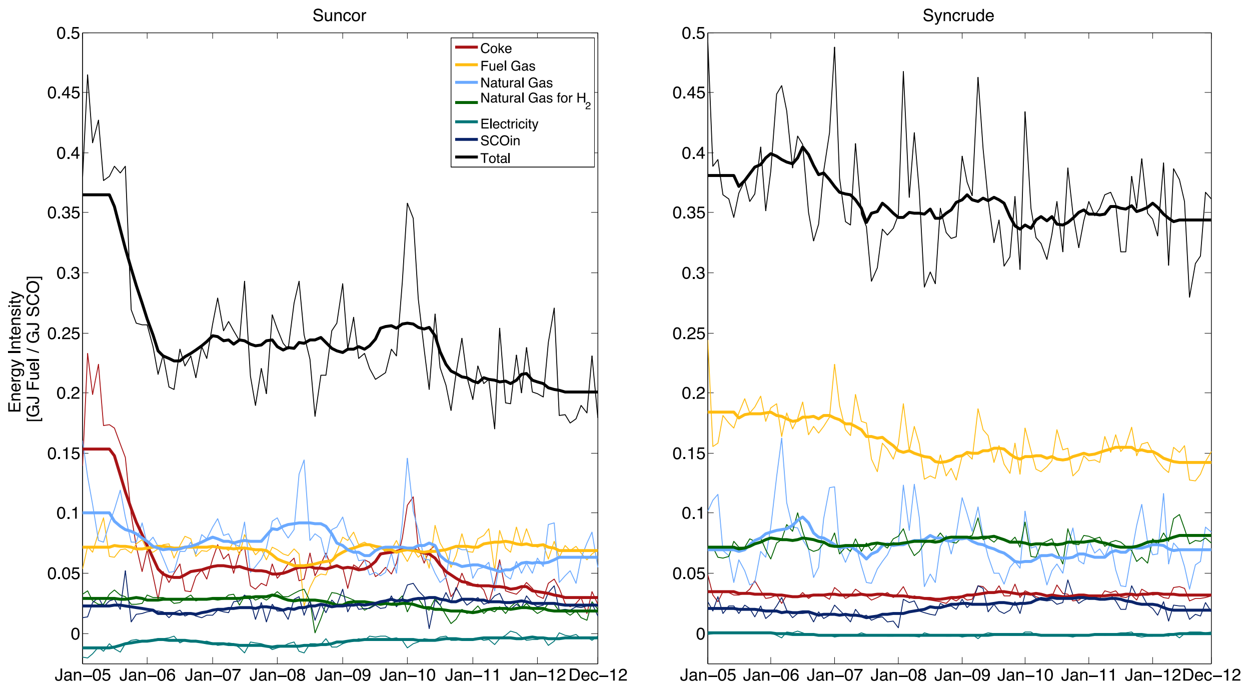

Figure 3 Fuel use intensity (*FS_{fp}*) for Suncor-MSV and Syncrude-Mildred Lake and Aurora mining projects (12-month moving averages are presented as bold lines)

mining and upgrading facility. The total natural gas and electricity intensity for Suncor-MSV and the natural gas intensity for Syncrude-Aurora are subtracted from those values.

The remaining fuel consumed per unit of bitumen produced is an approximation of the requirements to upgrade bitumen to SCO at Suncor-MSV. A representation of this method for natural gas is shown in Equation 6:

$$FS_{ng,SunFB,SCO} = \left(\frac{F_{ng,SunFB}}{P^{Bit}_{SunFB}} + FS_{ng,SunMSV,Bit} - FS_{ng,SynAur,Bit}\right) \cdot \frac{P^{Bit}_{SunMSV}}{P^{SCO}_{SunMSV}} \left[\frac{\text{MJ ng}}{\text{MJ SCO}}\right] \qquad \text{(eq. 6)}$$

A similar approach is used in the GHGenius model to estimate standalone upgrading energy use.

These resulting intensities for Suncor-Firebag and Nexen-Long Lake are combined with a production-weighted average fuel share as used in the other pathways:

$$P^{SCO}_{SunFB} = P^{SCO}_{SunMSV}\left(\frac{P^{Bit}_{SunFB}}{P^{Bit}_{SunFB}+P^{Bit}_{SunMSV}}\right) \quad [\text{MJ SCO}] \qquad \text{(eq. 7)}$$

$$FS_{f,IS+SCO} = \sum\nolimits_{p\in IS+SCO} FS_{fp,SCO}\left(\frac{P^{SCO}_{p}}{\sum_{p\in IS+SCO} P^{SCO}_{p}}\right) \quad \left[\frac{\text{MJ fuel}}{\text{MJ SCO}}\right] \qquad \text{(eq. 8)}$$

3 Data

This analysis uses energy production and consumption data reported by the AER (formerly the ERCB). These datasets provide detailed energy consumption data on a project-by-project basis, reported monthly.

3.1 Mining projects

3.1.1 Data gathering and handling

Data for oil sands mining and upgrading operations are gathered primarily from AER datasets ST39 and ST43, which record monthly quantities of energy sources consumed and produced (ERCB ST39 for 1970–2002 and 2009–2012, ST43 for 2003–2008). Monthly energy streams tracked in ST39 and ST43 and used in this study include the following:

- SCO produced, consumed, and delivered (1000 m^3);
- Bitumen produced and delivered (1,000 m^3);
- Coke produced, consumed, and stockpiled (tonnes);
- Purchased natural gas imported, consumed, processed for H_2 generation, and flared/wasted (1000 m^3);
- Produced fuel gas produced, consumed, processed for H_2 generation, and flared/wasted (1000 m^3);
- Intermediate hydrocarbons produced (1000 m^3); and
- Electricity produced, imported, exported, and consumed (MWh).

ST39 data are collected in Microsoft Excel files from 2008 through 2012. ST43 data and ST39 data from 2005 through 2007 are extracted from tables in PDF files by using ABBYY PDF Transformer 2.0. These reports are available for download for the years 2008 through 2012 on the AER website. Data prior to 2008 can be purchased from AER (see http://aer.ca/data-and-publications/statistical-reports/st39).

Some mining facilities integrate heat and power demands between the mine and upgrader. Therefore, it is a challenge to disaggregate the energy use reported in these datasets between the process of mining and separating bitumen from ore versus the process of upgrading bitumen to SCO. However, approximate breakdowns of energy use between mines and upgraders can be made (see Section 2.3.3).

Some projects in AER datasets are upgraders for in situ projects (such as the Nexen-Long Lake upgrader) or are upgraders that are not adjacent to a mine (such as Shell-Scotford) (ERCB ST39, ST43).

We do not include some projects in the mining calculations because they are not directly tied to mining projects (e.g., Williams Energy diluent plant). In addition, the Imperial-Kearl project is not included in this study because it is not yet fully operational and there are not sufficient data available to determine its energy intensity (only SCO/diesel consumption is reported).

Figure 3 illustrates fuel share ratios ($FS_{fp,SCO}$) for the two largest mining projects (about 60% of mining production) for 2005 through 2012. As the figure demonstrates, differences in upgrading technologies result in different resulting fuel mixes. The Syncrude-Mildred Lake and Aurora project, which uses fluid coking, uses more fuel gas per GJ of SCO produced than does the Suncor-MSV project, which uses delayed coking. In contrast, the Suncor-MSV project historically has consumed relatively more coke than has Syncrude-Mildred Lake.

3.1.2 Synthetic crude oil production and consumption

The primary output from oil sands upgraders is SCO. In recent years, upgraders have begun to export raw bitumen. SCO fractions are also consumed as a diesel fuel in heavy machinery in mines (e.g., trucks). SCO is also used as an input by Suncor-MSV, Syncrude-Mildred Lake, and CNRL-Horizon projects. SCO accounts for less than 10% of the total energy inputs in these projects (ERCB ST39, ST43). Sources for SCO data are given in Table 3. References for converting the physical units of SCO to energy units can be found in Table 4, and references for fuel properties are found in Table 5.

Table 3 Data sources for mining projects

Source	Unit	Data Source	Frequency	Years (Gaps)
SCO	m^3	ST39, ST43	Monthly	2005–2012
Bitumen	m^3	ST39, ST43	Monthly	2005–2012
Flared/wasted bitumen	m^3	ST39, ST43	Monthly	2005–2012 (Suncor 2005–2006)
Coke	m^3	ST39, ST43	Monthly	2005–2012
Fuel gas	m^3	ST39, ST43	Monthly	2005–2012
Flared fuel gas	m^3	ST39, ST43	Monthly	2005–2012 (Suncor, Syncrude: 2010; CNRL: March–May 2009)
Natural gas	m^3	ST39, ST43	Monthly	2005–2012
Flared natural gas	m^3	ST39, ST43	Monthly	2005–2012

Table 4 Energy conversion factors from the literature (lit) and from GREET

Energy Resource	Unit of Measure (AER data)	Reported (lit)	Energy Content HHV (lit)	Unit of Measure (lit)	Sources (lit)	Energy Content HHV (GREET)	Unit of Measure (GREET)	Energy Content HHV (GREET, English)	Unit of Measure (GREET, English)	GREET LHV/HHV Ratio
SCO	1000 m^3	Elemental comp.[a]	40.61	GJ/m^3	Wang et al. 2007; Speight 2008	38.56[b]	GJ/m^3	138,350	Btu/gal	0.937
Coke	tonnes	Elemental comp.[a]	34.9	GJ/tonne	Furimsky 1998, 2009; Netzer 2006; Ityokumbul 1994	33.26	GJ/tonne	28,595,925	Btu/ton	0.942
Fuel gas	1000 m^3	Chemical comp.	61.01	GJ/1000 m^3	Netzer 2006; Lohninger 2011	59.02	GJ/1000 m^3	1,584	Btu/ft^3	0.92
Natural gas	1000 m^3	Chemical comp.	40.86	GJ/1000 m^3	Lohninger 2011; EIA 2011	40.6	GJ/1000 m^3	1,089	Btu/ft^3	0.908
Bitumen	1000 m^3	Chemical comp.	42.3	GJ/m^3	(S&T)^2 2013	Not available	Not reported	Not available	Not reported	Not reported
Electricity	MWh	Grid mix	3.6	GJ/MWh	AESO undated; ERCB and Alberta Energy and Utilities Board 1999; Statistics Canada undated	Not available	Not reported	Not reported	Not reported	Not reported

[a] Elemental composition reported as fractions C, H, O, S.

[b] Modeled as crude oil in GREET.

Table 5 Fuel properties of oil sands products

Unit	LHV (Btu/gal)	HHV (Btu/gal)	Density (g/gal)	C Ratio (% by wt)	S Ratio (wt%)	API Gravity	Source
SCO	144,672	154,729	3,266	86	0.18	32	Crude Monitor 2013a
Dilbit	152,068	162,640	3,513	83	3.8	21	Crude Monitor 2013b
Synbit	152,739	163,357	3,539	84	2.99	19.6	Crude Monitor 2013c
Diluent	128,449	137,378	2,709	84	0.16	66	Crude Monitor 2013d
Bitumen	146,237	155,300	3,840	84	4.7	8	(S&T)^2 2013

3.1.3 Coke production and consumption

Coke is reported as a produced, consumed, and stockpiled quantity in AER datasets (ERCB ST39, ST43). Coke is a byproduct of the upgrading process for both the Suncor-MSV and Syncrude-Mildred Lake upgraders. Since coke's chemical composition is not given in AER datasets, multiple data sources for the composition and energy content of coke were gathered from the literature. The coke energy contents from the literature were found to be similar to GREET default values, so GREET values are used (given in Table 4).

3.1.4 Fuel gas consumption

Similar to coke, fuel gas is an intermediate product of the upgrading process. Its composition is more diverse than is natural gas's. The chemical composition of fuel gas ranges from H_2 to C_{4+}, with higher fractions of non-CH_4 species than of natural gas. Fuel gas is produced at all upgraders and is consumed at all of the upgrading facilities. Data sources for fuel gas consumption are provided in Table 3.

Although the composition of fuel gas is uncertain, this analysis assumes that the energy content of fuel gas is similar to that of refinery still gas in GREET (Bergerson et al. 2012). Evidence suggests that GREET's default energy content for fuel gas is reasonable (see Table 4).

3.1.5 Imported natural gas consumption

Natural gas is imported for all mining and upgrading projects. Natural gas consumption is reported in AER statistics as being consumed for plant use and consumed in further processing. AER staff noted that the "further processing" category represents use of natural gas for H_2 production [1000 m^3] (ERCB ST39, ST43). Data sources for natural gas consumption can be found in Table 3. (Table 4 shows the energy content of natural gas from GREET used in this analysis.)

3.1.6 Flaring emissions and wasted bitumen

Although the data reported are incomplete, flaring from upgraders is reported next along with energy consumption in AER datasets (ERCB ST39, ST43). These quantities are classified as "flared/wasted" for a variety of energy types, including natural gas, diluent, bitumen, and fuel gas.

The quantities reported for bitumen flared/wasted vary significantly among projects. According to AER personnel, natural gas, diluent, and fuel gas are flared, while bitumen is not flared but rather wasted (e.g., sent to tailings pond or disposed of in mines) (Mann 2013).

Wasted bitumen occurs as a result of separation processes. These waste products are different for each project. For example, the Albian Sands-Muskeg River “flared/wasted” bitumen is two orders of magnitude higher on a normalized basis than that of Suncor-MSV or Syncrude-Mildred Lake and Aurora. This occurs because the bitumen ore requires a separations process that produces pipeline-quality bitumen (which is subsequently sent to the Shell-Scotford upgrader). In this process, some of the higher carbon asphaltenes are separated and categorized as “flared/wasted.” This does not occur for the Suncor-MSV and Syncrude-Mildred Lake and Aurora projects. Bitumen that is categorized as flared/wasted is not included as an emissions source for this analysis.

3.1.7 Tailings ponds

CH_4 emissions from tailings ponds are among the most uncertain estimated sources of upstream GHG emissions in the surface mining pathways of oil sands production (Yeh et al. 2010). CH_4 emissions from tailings ponds vary widely. One of the most studied tailings ponds is the Mildred Lake Settling Basin (MLSB) associated with the Syncrude-Mildred Lake project. Methane bubbles were first observed in the early 1990s on the south side of the tailings pond, and by the end of 1999, it was reported that “40–60% of the 12 km^2 surface was considered an active bubble zone, with an estimated daily flux of 12 g $CH_4/m^2/d$” (or 2.43 g of $CH_4/m^3/d$, assuming an average depth of 4.93 m of tailings pond) in the most active areas. Siddique et al. (2008) reported a range of 0.9–114.2 g $CH_4/m^2/d$ based on measured and modeled estimates for MLSB and reported that on average, 25% of the study site is thought to be methanogenic. The estimated total methane emissions over 200 million m^3 tailings (10 km^2) was 8.9–400 million L of CH_4/d. Table 6 summarizes reported CH_4 emission rates from tailings ponds in g of $CH_4/m^3/d$.

Table 6 Observed CH_4 emission rates from tailings ponds and the derived emission rate (in g of $CH_4/m^3/d$)

Study	Reported Emission Rate at MSLB	Derived Emission Rate (g $CH_4/m^3/d$)
Holowenko et al. 2000	40–60% of the 12-km^2 surface was considered an active bubble zone, with an estimated daily flux of 12 g of $CH_4/m^2/d$ in the most active areas	0–12
Siddique et al. 2008	Emission rate of 0.9–114.2 g $CH_4/m^2/d$, with an estimated daily flux of 12 g $CH_4/m^2/d$ = 8.9–400 million L/d of CH_4 for 200 million m^3 of tailings	0.03–1.43
Siddique et al. 2011	Citing Siddique et al. (2008), estimate average of 0.2% naphtha in MLSB = 70 L of $CH_4/m^2/d$ = 175 million L/d of CH_4	0.63
Siddique et al. 2012	Citing Holowenko et al. (2000), estimate 43,000 m^3 of CH_4/d for 400 million m^3 of tailings	0.08

Methane gas is a GHG that has 25 times the potency of CO_2 over a 100–year assessment period (Solomon et al. 2007). In addition, this gas transport toxic compounds to the capping water faster, reduce the oxygen level of the lake, and produce ethylene, which affects plants (Holowenko et al. 2000). Amending tailings with sulfate, such as by adding gypsum ($Ca_2SO_4 \cdot 2H_2O$) in composite tailings, can significantly reduce or eliminate methane emissions in the laboratory (Holowenko et al. 2000; Salloum et al. 2002).

The values used in this report are extracted from GHGenius and can be found in the documentation for v4.03 in Section 28.2.2.2.2.2. The value reported in GHGenius is 5,000 L of CH_4/tonne bitumen. After conversion to fuel shares, these emissions equal 0.005 GJ and 0.0062 GJ of CH_4 per GJ of bitumen and SCO, respectively [(S&T)[2] 2011b]. The value from GHGenius (5,000 L of CH_4/tonne bitumen) was generated by taking the total emission volumes found in Table 4 from Siddique et al. (2011) (175 ML/d) and dividing this rate by the daily production for the Syncrude-Mildred Lake Mine (O'Connor 2014). This results in a value of about 8,000 L of CH_4/tonne bitumen, which is then combined with other sources to arrive at the overall estimate of 5,000 L of CH_4/tonne. Note that this approach assumes that the pond is at steady-state and that observed emissions are proportional to current production.

3.2 In situ projects

3.2.1 Data gathering and handling

Data on in situ project energy use and emissions are collected from a variety of sources. Where tabulated data are provided, they are collected directly from AER dataset ST53 for the study time period (ERCB ST53). Other data are gathered from yearly progress reports (YPRs). YPRs are given by project operators on approximately a yearly basis. The reports are designed to +keep regulators informed about project operations and performance. In contrast to mining datasets, for which nearly all relevant data are reported as official AER statistics, a lot of significant in situ data are reported to regulators only in YPRs. The timing of YPRs is somewhat sporadic.

In some cases, tabular data are not provided in YPRs. In these cases, data are extracted from graphs by using GraphClick software. Images are exported as PDFs from source documents. If resolution or confounding data series are a concern for a given graph, figures are exported at a large scale (1,000% magnification) and modified in Adobe Illustrator to remove extraneous curves that might interfere with data extraction. Automatic line detection in GraphClick is used where applicable to extract data. If automatic line detection is found to be inaccurate, data points are placed by hand. In order to test the accuracy of the graphical data extraction, data are gathered graphically for some projects for months in which tabulated data are also available. For this report, tabular and graphically extracted results were compared, and the divergence between the sources was found to be less than 1% in most cases.

A project is considered to be operational from the first month of either steam injection or bitumen production. Usually steam injection occurs before bitumen production, or injection and production begin in the same month. Some in situ projects are not included in the dataset due to a lack of data: PennWest Petroleum-Seal, Cenovus-Pelican Lake, and Baytex-Harmon Pilot. These projects were newly operational and did not report enough data for analysis before December 2012. Any uncertainty that results from excluding these projects is likely to be small, since these projects produce less than 1,000 bbl/d combined.

3.2.2 Bitumen production

Historical bitumen production [m^3/mo] from in situ operations is collected from AER ST53, which is available on a monthly basis from 1992 to the present (ERCB ST53). Data for the study time period were gathered directly from spreadsheets.

As mentioned previously, projects labeled "primary production" are not included in our in situ analysis, as these projects do not report energy consumption data to regulators. Primary production operations also produce resources that are not representative of the bulk of the oil sands resource (e.g., higher API gravity).

3.2.3 Steam injection

Data on historical steam injection from in situ operations are collected from AER datasets in units of m^3/mo (ERCB ST53). Although not included in this analysis, there is some documentation of steam quality by project in YPRs.

3.2.4 Natural gas and produced gas consumption

Natural gas consumption data have been reported by producers in YPRs since 2009. For illustrative purposes, the energy intensities of steam generation for the five largest projects are shown in Figure 4, including both natural gas and produced gas (m^3 gas/m^3 steam). In this study, we assume that produced gas has the same properties as natural gas. For the purpose of demonstration, the overall gas intensity (GJ gas/GJ bitumen produced) of bitumen production for the five largest projects is shown in Figure 5. Available data on natural gas and produced gas use are summarized in Table 7.

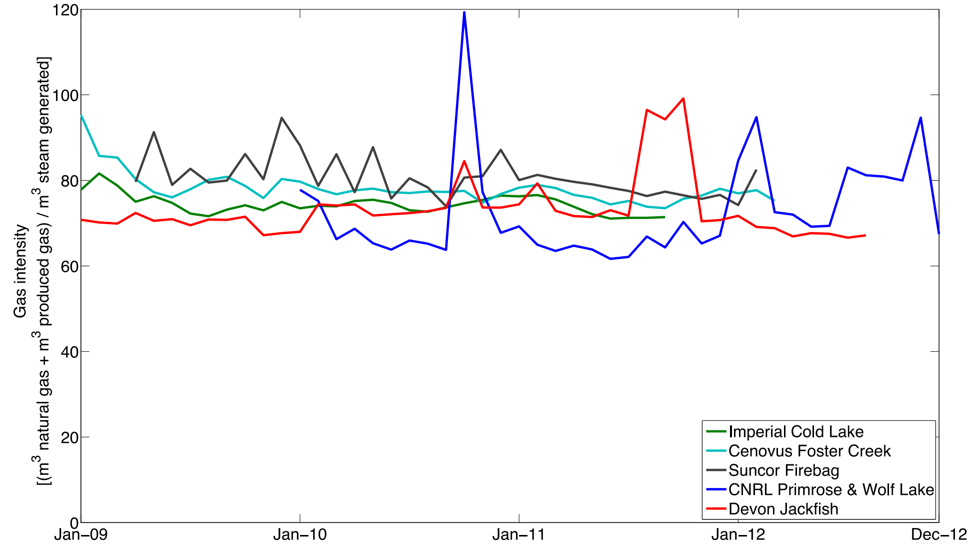

Figure 4 Monthly energy intensity of steam generation for the five largest in situ projects (m^3 gas/m^3 steam)

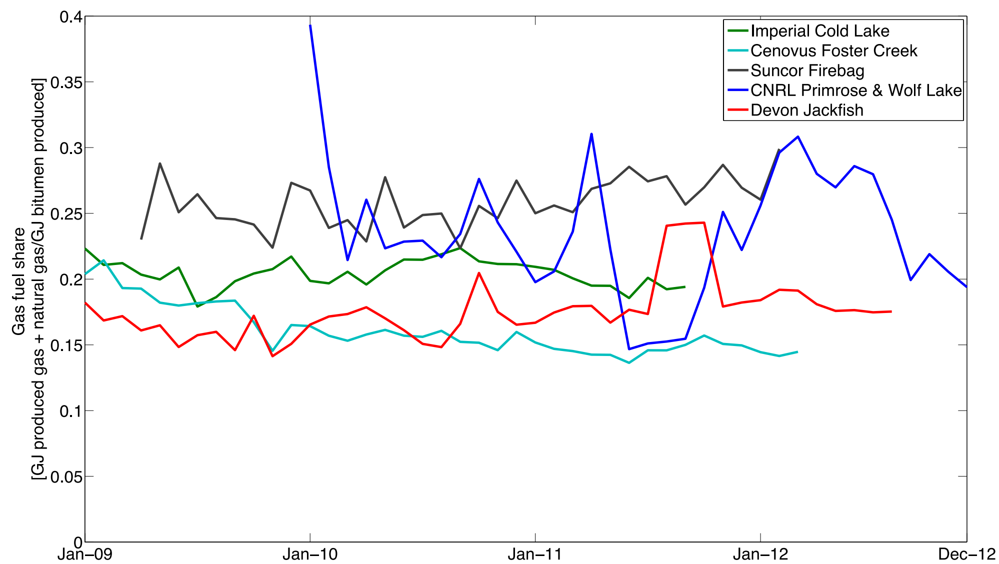

Figure 5 Monthly gas fuel share for the five largest in situ projects (GJ gas/GJ bitumen)

Table 7 Data sources for in situ projects

Source	Unit	Data Source	Frequency	Years (Gaps)
Bitumen	m^3	ST-53	Monthly	2009–2012
Steam injection	m^3	ST-53	Monthly	2009–2012
Natural gas consumed	m^3	YPRs	Monthly	2009–2012
Produced gas consumed	m^3	YPRs	Monthly	2009–2012
Flared natural gas	m^3	YPRs	Monthly	2009–2012
Flared produced gas	m^3	YPRs	Monthly	2009–2012
Electricity consumed	MWh	YPRs	Monthly	2009–2012
Electricity generated	MWh	YPRs	Monthly	2009–2012
Electricity imported	MWh	YPRs	Monthly	2009–2012
Electricity exported	MWh	YPRs	Monthly	2009–2012

3.2.5 Electricity generation, consumption, imports, and exports

Some in situ projects generate electricity using cogeneration, while others purchase power from the grid. Electricity generation, consumption, imports, and exports from each project have been reported by producers in YPRs since 2009. For the purpose of demonstration, the electricity intensity of fluid handling (MWh/m^3 steam or GJ/GJ bitumen) for the five largest in situ projects is shown in Figure 6. The overall electricity intensity of bitumen production is shown in Figure 7. Negative values indicate that the project co-generates its electricity and is a net exporter. Available data for electricity net imports are summarized in Table 7.

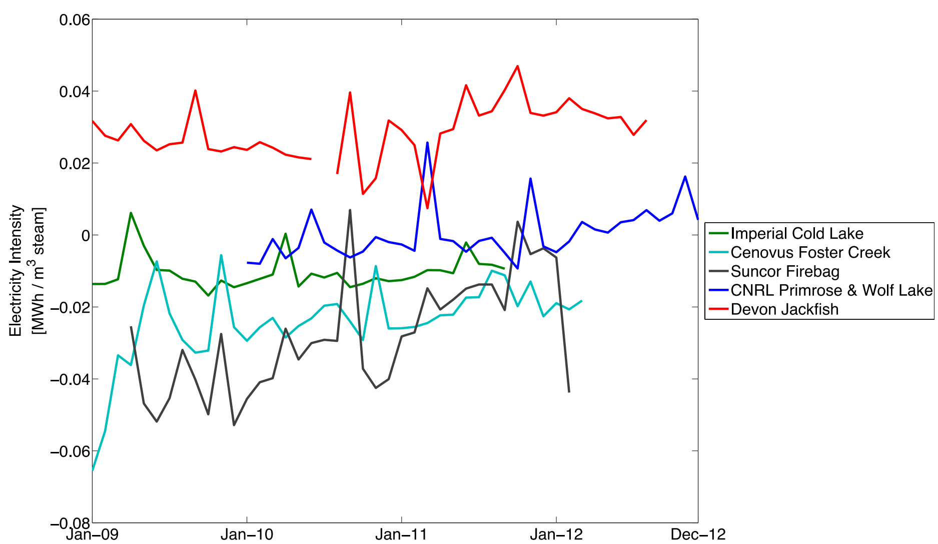

Figure 6 Monthly electricity intensity of steam production for the five largest in situ projects

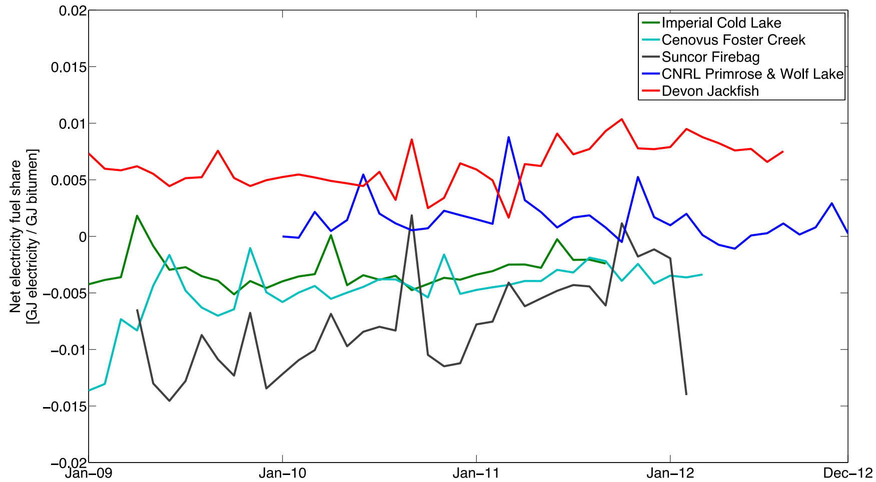

Figure 7 Monthly electricity intensity of bitumen production for the five largest in situ projects

3.2.6 Flaring and fugitive emissions

Two sources of flaring and fugitive emissions occur with in situ production: on-site emissions and emissions at crude bitumen batteries (gathering and storage facilities).

On-site flaring and venting volumes have been reported in YPRs since 2009. Flaring and fugitive intensities (m^3 flared/m^3 bitumen and m^3 vented/m^3 bitumen) are generated. Available data sources on flaring and fugitive emissions are summarized in previously in Table 6.

Facility-level emissions for thousands of facilities across Alberta are reported in ST60B datasets (ERCB 2011). However, these emissions cannot be assigned to individual in situ production projects. We instead compute flaring and venting intensities from aggregated statistics for quantities of gases flared and vented from crude bitumen batteries (ERCB 2011; previously in Tables 4 and 5). Data in ST60B are reported from 2000 through 2011. For 2012, we use the same value as the 2011 values. These data are used to estimate venting and flaring per unit output of bitumen (m^3 vented/m^3 bitumen and m^3 flared/ m^3 bitumen).

3.3 Energy contents of fuels

3.3.1 Energy contents

Energy contents for included product streams are reported in Tables 4 and 5. A literature review found good agreement between values from GREET and from the literature on the energy contents of coke, fuel gas, and natural gas (Furimsky 1998; Furimsky 2009; Netzer

2006; Ityokumbul 1994; EIA 2011). Therefore, this analysis uses default GREET energy contents for all energy sources except bitumen, which is not included in GREET.

3.3.2 Electricity

Although some projects generate sufficient electricity on-site and even sell electricity back to the grid, other projects have historically imported electricity from the grid. To account for associated GHG emissions, the energy efficiency and fuel mix of the Alberta grid were calculated as a time series by using data from Statistics Canada 57-202 reports for 2005, 2006, and 2007 (Statistics Canada undated) and data from the Alberta Electric System Operator (AESO) annual market statistics reports for 2008 through 2012 (AESO undated). Datasets provide values in physical units for fuel consumed (e.g., Mg of coal, m^3 of gas) and data on associated power plant heat rates and aggregate electricity generated (AESO undated; Alberta Energy and Utilities Board undated; ERCB and Alberta Energy and Utilities Board 1999; Statistics Canada undated). Some datasets provide monthly data, but the majority provide annual data. In order to regularize data across all time intervals, we calculated an annual average when monthly data were available.

Our analysis assumes that electricity imports and exports displace power with the same thermal efficiency and fuel mix as that of the average Alberta grid; however, this input into GREET will be separate from the oil sands pathways.

Note that for all projects that produce and use co-generated electricity on-site, it is assumed that the energy requirement for electricity production is accounted for through the primary fuel consumption. This assumption is made because the end use of a particular primary fuel is not designated in the data. For example, an upgrader will report total natural gas consumed for a particular month but will not designate how much of that gas was used to produce electricity versus how much was used in the separator. Likewise, for a co-generating in situ project, the energy required to produce the on-site electricity that is consumed is assumed to have been accounted for in the site's natural gas consumption for that particular month.

The thermal efficiency and fuel mix of the Alberta grid over the study time period is presented in Table 8. Although heating rates were reported for coal for 2005 through 2007 and for gas for 2005 through 2012, the data do not indicate whether a higher heating value (HHV) or an LHV was reported; thus, we assume that the data are reported on an HHV basis.

Table 8 Alberta grid makeup with thermal efficiency

Type of Generation, Thermal Efficiency	2005	2006	2007	2008	2009	2010	2011	2012
Generation type								
Hydro	0.04	0.03	0.04	0.07	0.07	0.07	0.1	0.1
Coal	0.74	0.72	0.73	0.72	0.72	0.71	0.67	0.64
Natural Gas	0.2	0.22	0.21	0.17	0.18	0.19	0.19	0.21
Wind	0.01	0.01	0.01	0.03	0.03	0.03	0.04	0.04
Other	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Thermal efficiency (GWh/GWh)[a]	0.34	0.33	0.31	0.33	0.33	0.33	0.33	0.33

[a] Reported data do not distinguish between HHV and LHV. HHV is assumed.

4 Results

This section presents graphical and tabular results for Pathway Option 3 as defined previously (Pathway Options 1 and 2 are presented in Appendix A).

4.1 Historical trends

The overall fuel shares for each pathway represent volume-weighted average fuel intensities over the time period of analysis (2005–2012 for mining projects and 2009–2012 for in situ projects). For the fuel pathway inputs into GREET, time trends for the fuel shares are collapsed into pathway averages. These variations can be seen for the M+SCO and the IS+Bit pathways in Figure 8 and Figure 9. Each datapoint represents the volume-weighted average intensity for each fuel in each month.

Figure 8 shows that the overall energy intensity ratios of the M+SCO pathway do not exhibit significant time-dependent trends. Histograms plotting variation of each fuel intensity are shown in Figure 10. Longer-term trends in fuel intensity for the M+SCO pathway show that there has been an overall decline in coke consumption over what it was in prior decades; it has been displaced somewhat by natural gas (Englander et al. 2013; Brandt et al. 2013). Natural gas consumption appears to vary periodically, spiking in the winter months. More recent trends include a decline in fuel gas consumption that has coincided with a short spike in fuel gas for hydrogen generation, an increase in natural gas consumption, and a slight decrease in net electricity exports.

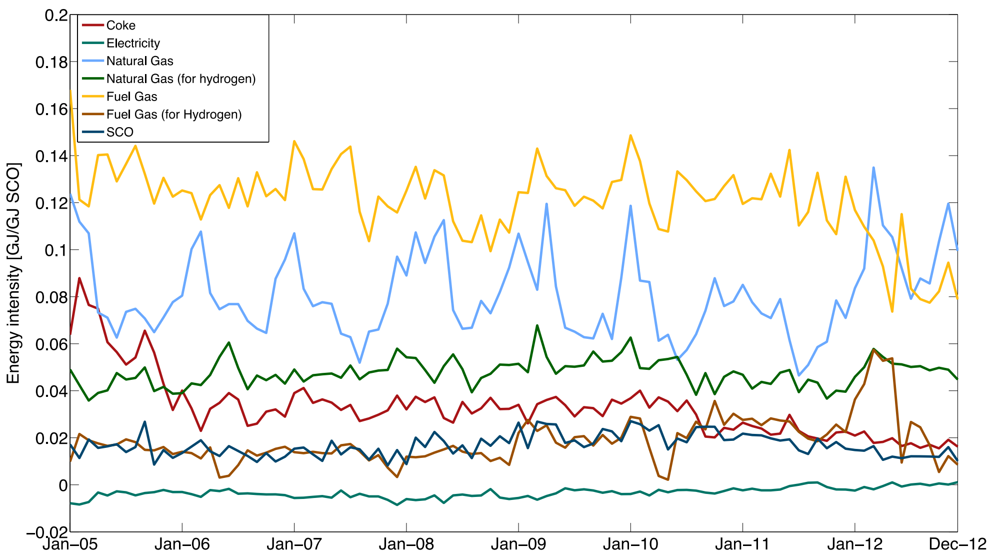

Figure 8 Weighted average fuel shares for the M+SCO pathway for 2005–2012

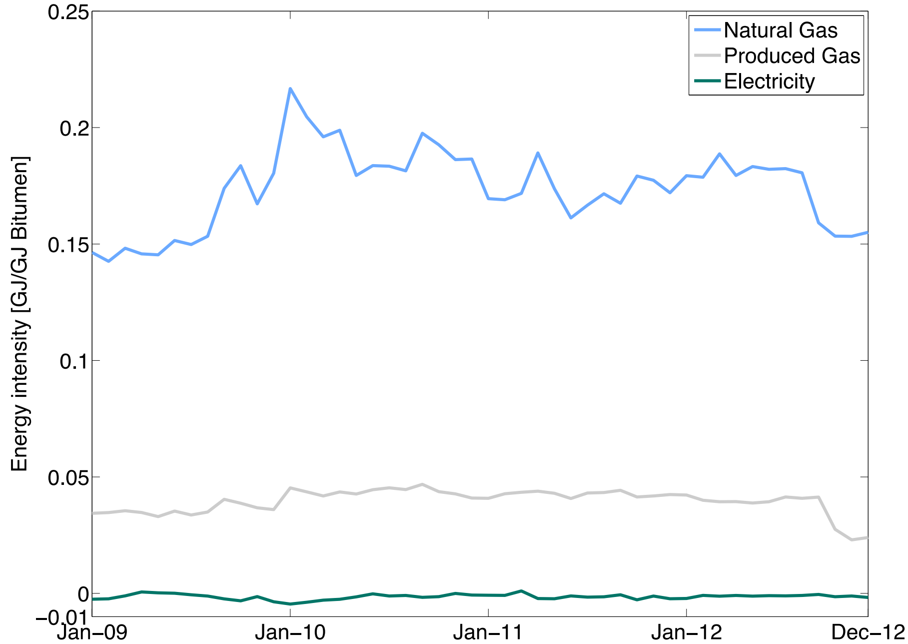

Figure 9 Weighted average fuel shares for the IS+Bit pathway for 2005–2012

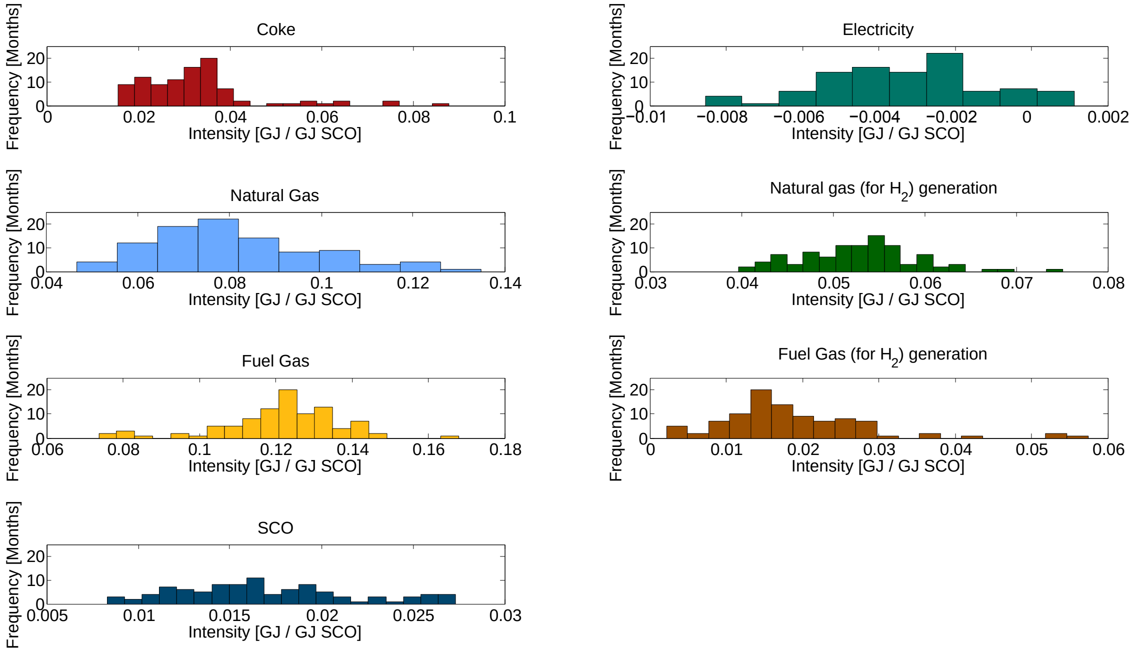

Figure 10 Histograms of fuel intensities for M+SCO pathway

Although the production-weighted intensity values have not changed significantly, there have been some changes in the upgrading technology used. Figure 11 represents a six-month moving average of the fraction of mined bitumen that is produced via one of the three currently available upgrading technologies: delayed coking, fluid coking, and hydrocracking.

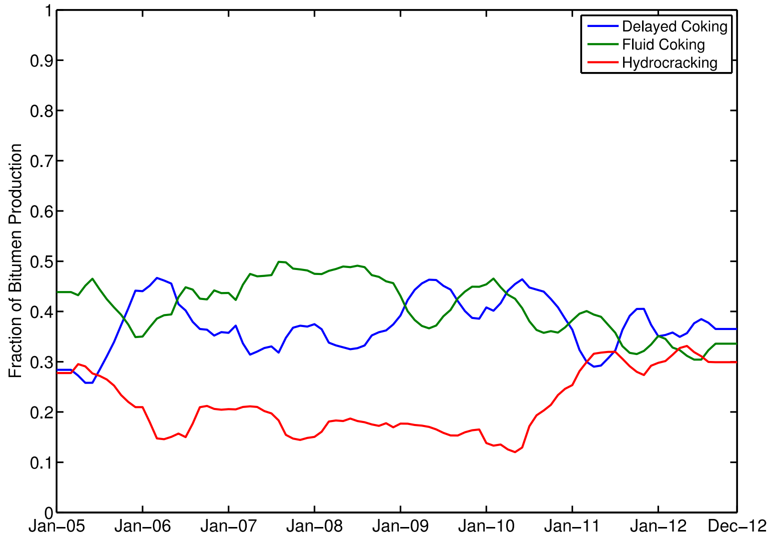

Figure 11 Six-month moving average of fractional bitumen production by upgrading technology (Delayed coking projects are Suncor-MSV and CNRL-Horizon; fluid coking project is Syncrude-Mildred Lake; hydrocracking project is Shell-Scotford)

Although the share of upgrading technologies at the beginning and the end of the study period are very similar in terms of the overall share between coking and hydrocracking, there has been a decrease in fluid coking; it has been replaced by delayed coking. This shift is reflected in the decrease in fuel share for fuel gas, as seen in Figure 8.

As Figure 9 demonstrates, the trends for the IS+Bit pathway are less defined. In 2012, there was a decrease in natural gas consumption and also a slight decrease in produced gas consumption. It is unclear if such trends will continue. It is likely that the increase in SAGD as a share of in situ production over CSS has allowed for more efficient extraction. Evidence of the relative efficiency of SAGD over CSS extraction can be seen in Figure 12.

4.2 Graphical results

The resulting fuel intensities (FS_f) are presented in Figure 13, which plots mean values of FS_f by pathway over the study period. The uncertainty range for each pathway represents the 10–90 percentile range for the overall energy intensity for each pathway, with each month of data representing an observation (96 observations for the mining pathways and 48 observations for the in situ pathways).

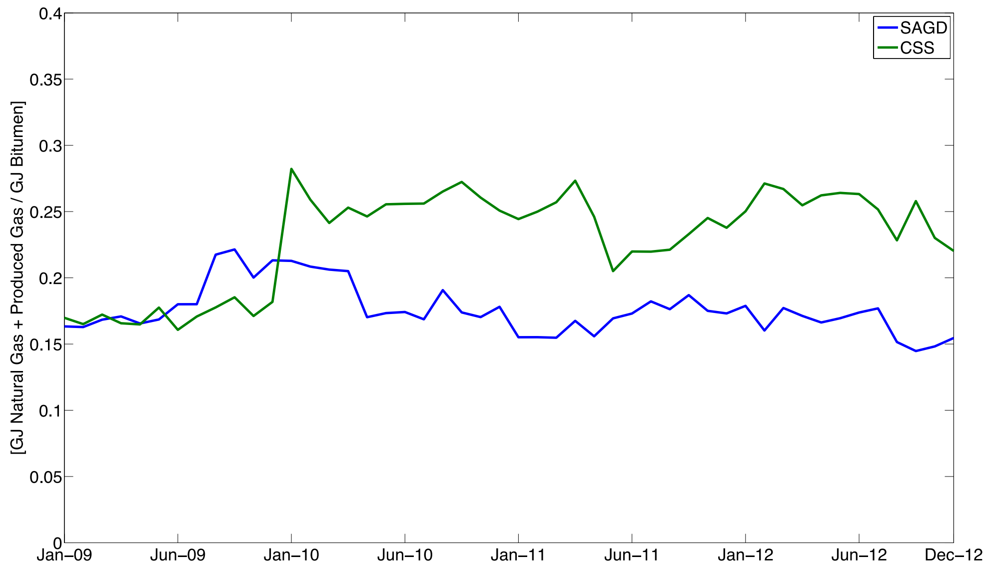

Figure 12 Monthly production-weighted average fuel share for CSS versus SAGD (GJ gas/GJ bitumen)

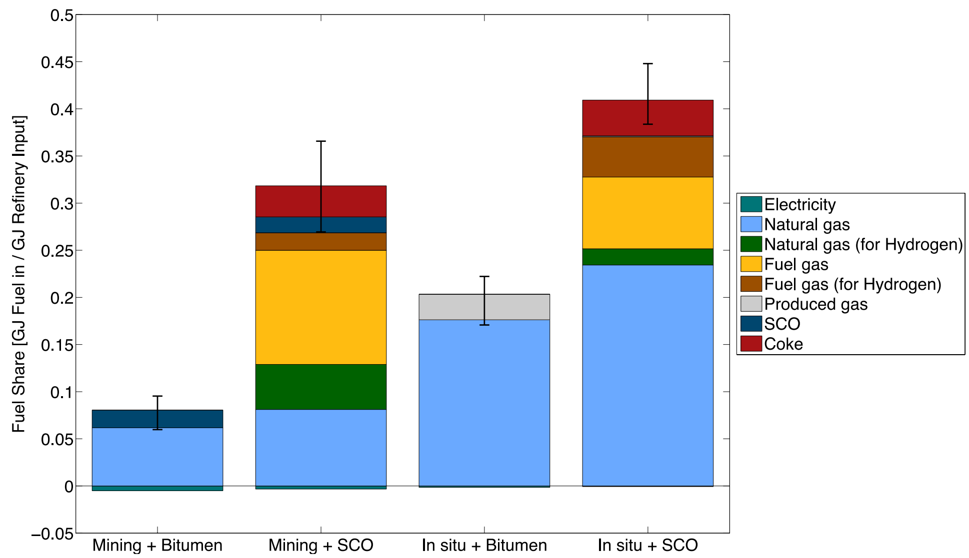

Figure 13 Fuel shares $FS_{f,M+Bit}$, $FS_{f,M+SCO}$, $FS_{f,IS+Bit}$, and $FS_{f,IS+SCO}$ for refinery input differentiated pathways (Results are reported in Table 9.)

4.3 Energy intensities

As highlighted in Figure 13, there are significant differences between the different oil sands production pathways. The most fuel-efficient pathway is the M+Bit pathway, and the least fuel-efficient pathway is the IS+SCO pathway. Table 9 presents detailed fuel-specific consumption results along with the fraction of production produced. Flaring rates are also included in Table 9.

Table 9 Fuel shares and flaring intensities (GJ/GJ of bitumen or SCO delivered) by pathway, with mean results from 2005–2012, with 10th to 90th percentile (p10–p90) ranges[a]

Fuel Shares and Flaring Intensities	Results per Pathway with 2005–2012 Production Share											
	M+Bit 3.4%			M+SCO 56.0%			IS+Bit 34.7%			IS+SCO 5.9%		
	Mean	p10	p90	Mean	p10	p90	Mean	p10	p90	Mean	p10	p90
Fuel consumption												
Coke	–			0.03	0.02	0.05	–			0.04	0.03	0.06
SCO	0.02	0.01	0.03	0.02	0.01	0.03	–			–		
Produced gas	–			–			0.03	0.02	0.03	0.001	0.0001	0.002
Fuel gas	–			0.12	0.11	0.14	–			0.08	0.07	0.09
Fuel gas for H_2	–			0.02	0.01	0.03	–			0.04	0.03	0.07
Natural gas	0.06	0.05	0.08	0.08	0.06	0.11	0.17	0.15	0.20	0.23	0.22	0.25
Natural gas for H_2	–			0.05	0.04	0.06	–			0.02	0.01	0.03
Net electricity	−0.005	−0.008	−0.002	−0.003	−0.006	0	−0.002	−0.003	−0.000	−0.0006	−0.005	0.0047
Total	0.08	0.06	0.1	0.32	0.27	0.37	0.20	0.17	0.23	0.41	0.38	0.45
Flaring and fugitive gas emissions												
Diluent	–			0.003	0.002	0.003	–			0.002	0.0017	0.0021
Produced gas	–			–			0.0006	0.0002	0.002	0.0001	0.00	0.0001
Fuel gas	–			0.002	0.001	0.004	–			0.004	0.002	0.007
Natural gas	–			0.0004	0	0.001	–			0.03	0.006	0.05
Tailings and mine face fugitives	0.005	–	–	0.006	–	–	–			–		
Bitumen batteries	–			–			0.007	–	–	–		

[a] A dash means for that pathway, there are no inputs for that particular fuel. If that is the case for the mean, then the P10 and p90 cells are blank. A zero means that data are there but were calculated to be zero.

There is variability in fuel shares, as shown in Figure 10 and Figure 14 for the M+SCO and IS+Bit pathways, respectively. This variability represents month-to-month variation for the production-weighted average of each fuel intensity and reflects the relative variability of individual fuel shares. The magnitude of variability for each pathway has different underlying causes. The relatively lower variability of the M+Bit pathway is due to fact that a small number of projects have been at industrial scale for a long time. The M+SCO pathway has more variation due to the larger variety of fuels used as well as the differences in upgrading technologies aggregated within the pathway. The most significant variation is found in fuel gas consumption for the M+SCO pathway and in natural gas consumption for both the M+SCO and IS+Bit pathways. The IS+Bit pathway has relatively low variability due to the developed nature of steam generation technology as well as the relative stability in fuel intensity as projects operate at scale. This finding contrasts with the IS+SCO pathway, which has the most variability. There are only two projects represented in this pathway, but unlike projects in the M+Bit pathway, they have not been operating at scale for the entirety of the 2009–2012 study period.

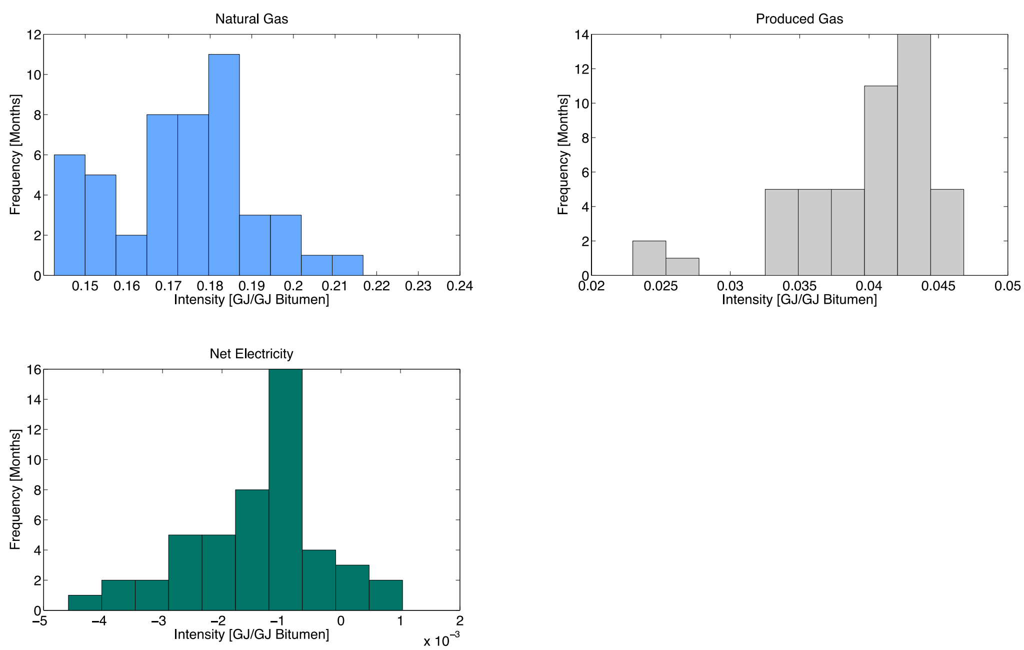

Figure 14 Histograms of fuel intensities for IS+Bit pathway

4.4 Comparison with previous studies

This section compares the energy intensities found in this report with those from the GHGenius model version 4.03a and the GHOST model [(S&T)[2] 2013; Bergerson et al. 2012; Charpentier et al. 2011]. The results of this comparison can be seen in Table 10 and Figure 15.

A comparison of GREET 2013 results with GHGenius results shows that GHGenius and GREET 2013 energy intensities are largely similar for three of the four pathways. One notable difference includes increased gas consumption for the IS+Bit pathway. When

Table 10 Comparison of study results with GHGenius and GHOST energy intensities (Upgrading pathways are presented in units of GJ of fuel consumed per GJ of SCO produced. Refining pathways are presented in units of GJ of fuel consumed per GJ of bitumen produced. See footnote e for methods used.)

	M+Bit			M+SCO			IS+Bit			IS+SCO	
Product	**GHGenius v 4.03a**[a]	**GHOST Example Cogen (Low–High)**	**GREET 2013**	**GHGenius v 4.03a**[b]	**GHOST Example Cogen (Low–High)**	**GREET 2013**	**GHGenius v 4.03a**[c]	**GHOST Base Cogen SAGD (Low–High)**	**GREET 2013**	**GHGenius v 4.03a**[d]	**GREET 2013**
Diesel/SCO	0.03	0.009 (0.006–0.013)	0.019	0.01	0.01 (0.007–0.015)	0.017	–[e]	–	–	–	–
Coke	–	–	–	0.04	–	0.033	–	–	–	0.03	0.038
Flared gas	–	0.001 (0.000–0.007)	0[e]	–	0.004 (0.003–0.013)	0.003	–	–	0.001	–	0.04
Fugitive gas	0.005	0.001 (0.000–0.002)	0.005	0.0062	0.001 (0.000–0.002)	0.0062	–	–	0.007	–	–
Natural gas	0.06	0.067 (0.029–0.109)[e]	0.062	0.12	0.170 (0.044–0.297)[e]	0.13	0.23	0.208 (0.173–0.254)[e]	0.173	0.33	0.252
Produced gas	–	–	–	–	–	–	–	0.000 (0.000–0.001)	0.027	–	0.001
Fuel gas	–	–	–	0.08	0.100 (0.073–0.173)	0.14	–	–	–	0.1	0.119
Net electricity	−0.006	0	−0.005	−0.002	0	−0.003	−0.005	0	−0.002	−0.01	−0.01

[a] Energy density of SCO is 44.8 GJ/tonne, from GHGenius "Fuel Char" sheet M90. Integrated mining to SCO uses data for "Integrated Operation," GHGenius "Crude Production" sheet N293:N301. No changes are made to input mix for integrated mining.

[b] Energy density of bitumen is 42.7 GJ/tonne, from GHGenius "Fuel Char" sheet M89. Changed GHGenius "Crude Production" sheet D290:G290 to reflect 100% mining. Extract energy intensities in kJ/tonne bitumen from I293:I301.

[c] Energy density of bitumen is 42.7 GJ/tonne, from GHGenius "Fuel Char" sheet M89. Changed GHGenius "Crude Production" sheet D290:G290 to reflect 60% CSS and 40% SAGD, since this is the production-weighted average over the time period. Took energy intensities in kJ/tonne bitumen from I293:I301.

[d] Energy density of SCO is 44.8 GJ/tonne, from GHGenius "Fuel Char" sheet M90. Changed GHGenius "Crude Production" sheet D290:G290 to reflect 100% SAGD. Took energy intensities in kJ/tonne SCO from M293:M301.

[e] A dash means for that pathway, there are no inputs for that particular fuel. A zero means that data were there but were calculated to be zero. GHOST model results are from the sources that follow. Data for mining and mining and upgrading cases are from Bergerson et al. (2012, Table 1). Results used are from "example scenario" for each case. Cogeneration case natural gas usage data for all pathways are from a personal communication (Bergerson 2013). These datapoints are marked with superscript *f*. SAGD energy use data for SAGD case are from Charpentier et al. (2011, Table 2). SAGD natural gas usage data provided in both cogeneration and non-cogeneration cases are from Bergerson (2013). Physical units of measure presented in Bergerson are m^3, kg CO_2, L, and kWh. These are converted to energy quantities in GJ by using the same energy contents used in the GREET 2013 study: diesel = 35.8 MJ/L; coke = 31.3 MJ/kg; natural gas, produced gas = 36.6 MJ/m^3; fuel gas = 54.3 MJ/m^3; and electricity = 3.6 MJ/kWh. Flared gas and vented gas are converted to energy quantities assuming a composition of 85% C1, 5% C2, 2% C3, 1% C4, and 7% CO_2. The resulting conversion factors are 2.2 kg CO_2equivalent/m^3 for flared gas and 15.2 kg CO_2equivalent/m^3 for vented gas.

32

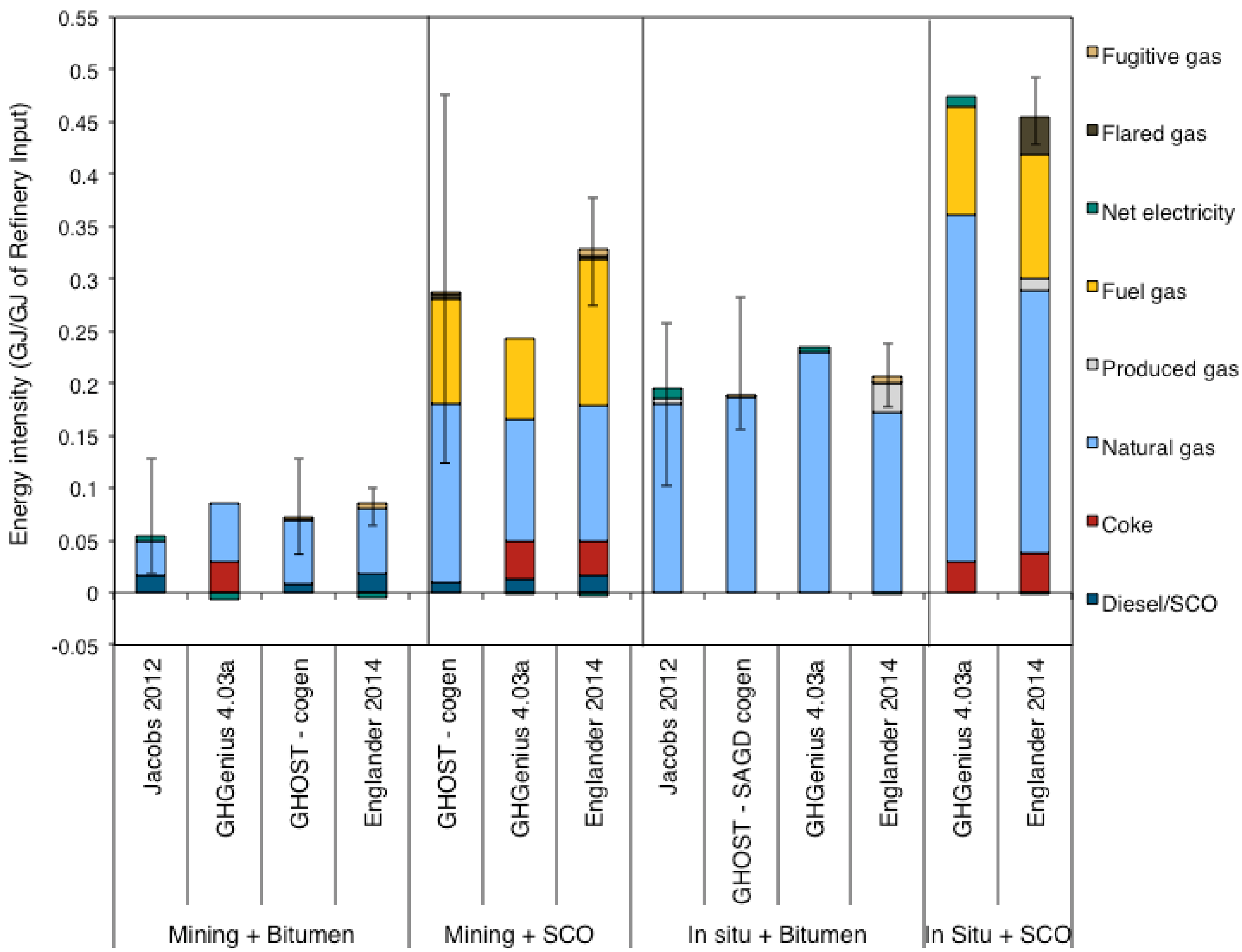

Figure 15 Energy consumption for each pathway, including results from GREET 2013 update, GHGenius v. 4.03a, and GHOST (See Table 10 for numerical results.)

examining the IS+Bit pathway, the major difference between the models is the treatment of produced gas. A larger volume of produced gas is consumed in cyclic steam stimulation projects. It is unclear how GHGenius includes produced gas consumption. The IS+SCO pathways are notable, since GHGenius has higher consumption of natural gas and electricity, while GREET has slightly higher coke consumption. These differences could be due to pathway definitions or to the choice of in situ projects used for upgrading. As discussed in the methods section, attributing the energy consumption of upgrading to in situ production requires some judgment. Differences in assigning energy usage would cause a variation in results. It is also possible that the in situ projects used by GHGenius for the IS+SCO pathway have different steam oil ratios (SORs) and therefore different natural gas consumption values. This occurs because the GREET IS+SCO pathway uses the two in situ projects that currently send bitumen to upgrades to produce SCO (Suncor-Firebag and Nexen-Long Lake), while GHGenius uses pathway average in situ consumption values. Another difference between the two models is the larger energy use for the M+SCO pathway in GREET. The reasons for this discrepancy are not clear, because GHGenius uses regulatory datasets similar to those used in this study to model these processes. The discrepancy appears to be similar in magnitude to the energy used for H_2 production in the form of natural gas and fuel gas (noted in AER statistics as gas used for “further processing”).

The results of the comparison with the GHOST model are shown in Table 10 and Figure 15. First, we note that reported GHOST processes do not, in all cases, align with GREET 2013 pathway definitions. For this reason, we create comparison cases that are comparable to the GHOST definitions as follows:

- GHOST mining figures are compared to the GREET 2013 M+Bit pathway, as defined above.

- GHOST delayed coking and hydrocracking are aggregated on a volume-weighted basis to the GREET M+SCO pathway, with a weighting of 78% to coking and 22% to hydrocracking.

- In the table, the GHOST SAGD case is compared to the overall GREET 2013 IS+Bit pathway.

For the GHOST mining and upgrading cases, we combine the GHOST mining results with the GHOST upgrading results and adjust mining energy consumption for the volumetric gain/loss associated with upgrading (m^3 SCO per m^3 bitumen) (Bergerson et al. 2012, Table 1).

Note that published GHOST cases with co-generation have very large electricity outputs, representing a “total potential” for cogeneration. It is unclear how these cogeneration cases can be compared to GREET 2013 results, so instead we used results from cogeneration for a “base cogeneration” case, where only enough power as that needed on-site is generated via cogeneration. These values were reported in a personal communication (Bergerson 2013). Note that we do not make assumptions about efficiency, power ratios, or capacities here, but simply use the GHOST base cogeneration case as given by Bergerson.

There are a few differences between GHOST and GREET 2013 results. The overall uncertainty ranges for GHOST are wider than those for GREET 2013. The reason for this is that the GREET 2013 results are calculated by using volume-weighted average time series, while GHOST is calculated on a project-by-project basis. GREET 2013 estimates of energy use in hydrocracking-based upgrading are significantly larger than those from the GHOST model. The reasons for this difference are unclear. GHOST does not include coke consumption for the M+SCO pathway. The IS+Bit pathway is slightly higher than the GHOST SAGD pathway. This difference is due to the inclusion of CSS production, which has higher energy intensity values than does SAGD (see Figure 11). In the GREET 2013 representation, SAGD accounts for 53% and CSS accounts for 47% of the IS+Bit pathway. Also, flaring and fugitive gas emissions for the SAGD case are larger than those for the GREET 2013 model.

This is because GREET 2013 uses data on flaring and venting emissions from crude bitumen batteries, using data from AER report ST60B, while the GHOST model does not include this emissions source.

5 Limitations of analysis

A number of uncertainties exist in this analysis.

Uncertainties related to pathway definitions were noted previously in the text on methods. Since this study relies on public data sources, some pathway uncertainties are likely to remain regardless of the aggregation and modeling method chosen. We believe that these uncertainties are minor in the aggregate due to their occurrence in minor pathways.

This analysis neglects embodied energy in capital equipment (e.g., steel for SAGD wells, upgraders, pipelines, etc.). We estimate that these sources are small enough that they would not have a significant impact on the total energy intensity.

The fuel mix for electricity production is another source of uncertainty. Our baseline assumption is that electricity debits or credits are calculated based on using the average fuel mix of the Alberta grid. Since oil sands facilities run constantly (barring upsets), the electricity imported would be from a relatively even mixture of power sources on the grid. An alternative method would be to model the marginal displacement of power plants as a function of time. This would require modeling the grid in the Athabasca region (which is primarily powered through co-generation from oil sands facilities) as well as the grids in other oil sands producing regions (which are closer to the Alberta average grid). It is unlikely that the increase in fidelity that would be obtained through this effort would be large.

Also, emissions from land cover change, methane emissions from the mine face, and methanogenic production from tailings ponds for the mining projects are uncertain ($(S\&T)^2$ 2011a; Siddique et al. 2008; Yeh et al. 2010). This uncertainty is discussed further in the Yeh et al. (2010) report.

Lastly, various grades of products are exported from oil sands projects. We divided the projects into those that export SCO and those that export diluted bitumen, but, in reality, various grades of SCO and various diluted products are produced. Given that these products are different in composition, they will have different downstream refining energy intensities. No known datasets allow for the disaggregation of these broad product classes into different energy consumption types.

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Appendix A: Description of Alternative Pathways

A.1 Industry-wide pathway

The most general representation of oil sands is to use a single production-weighted average process to represent all oil sands production. This pathway could be useful for comparisons of the overall oil sands industry to other petroleum production industries. Pathway process fuel shares are computed as follows:

$$FS_{fp} = \frac{F_{fp}}{P_p^{out}} \quad \left[\frac{\text{MJ fuel}}{\text{MJ product}}\right] \qquad \text{(eq. 9)}$$

$$FS_{f,ind} = \sum_{p \in all} FS_{fp} \left(\frac{P_p^{bit}}{\sum_{p \in all} P_p^{bit}}\right) \quad \left[\frac{\text{MJ fuel}}{\text{MJ product}}\right] \qquad \text{(eq. 10)}$$

where FS_{fp} is the fuel share for each fuel f for a project p (GJ consumed/GJ output product), F_{fp} is the fuel consumed of type f and project p (GJ fuel consumed), P_p^{out} is the product output by project p (GJ product output),. $FS_{f,ind}$ is the industry-wide share of fuel type f per unit of output, and P_p^{bit} is the bitumen produced by a given project p (GJ bitumen extracted). Note that each of these quantities is evaluated by using monthly input data, but with time indices suppressed for clarity.

The industry-wide pathway definition uses primary bitumen production as the weighting factor to combine emissions across projects. End products (P^{out}) could also be used to weight project impacts, but due to the differences in the quality of bitumen (GJ) and of SCO (GJ), doing so results in different denominators across different projects (see text that follows). Although Pathway Option 1 has the benefit of presenting the energy consumption of the industry as a whole, it does not differentiate between different production methods (surface mining and in situ production). It also does not differentiate between that products, treating a GJ of SCO equivalently to a GJ of diluted bitumen. Given that SCO and dilbit have different refinery requirements and energy intensities, this is an undesirable feature. Figure A-1 represents the aggregated fuel use for a volume-weighted average of refinery input from the oil sands.

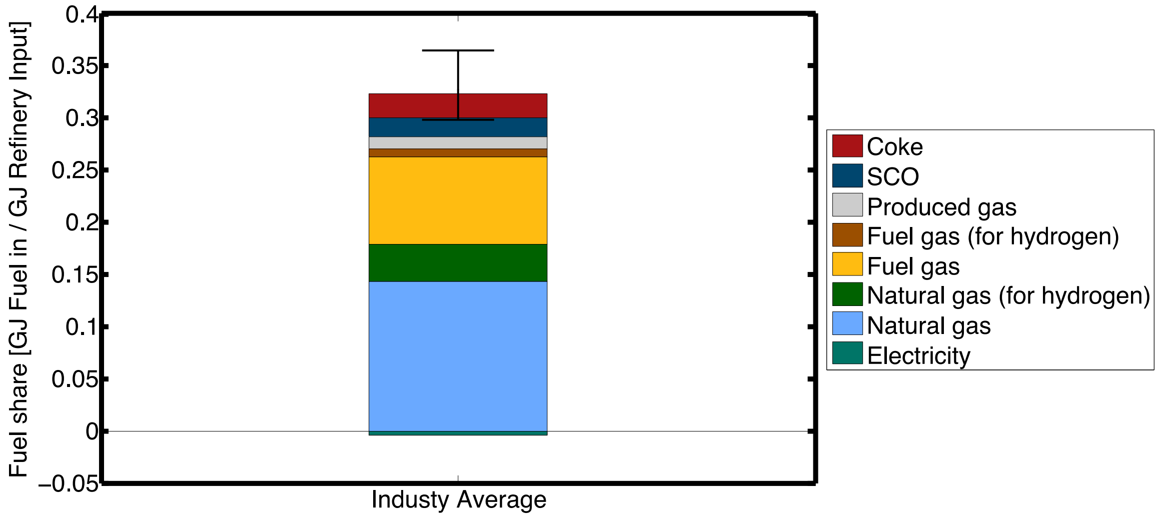

Figure A-1 Fuel shares ($FS_{f,ind}$) for the industry-average pathway (Pathway Option 1)

A.2 Production method pathway

Pathway Option 2 aggregates projects based on their primary production method. This formulation is similar to the GREET v. 1_2012 formulation, which differentiates between surface mining and in situ production. Because this method combines different output products (as does Pathway Option 1), primary bitumen production is used as the weighting factor. This method represents processes with increased fidelity because it differentiates between in situ and mining projects. However, this method also still combines outputs (SCO and dilbit).

As before, we define the fuel shares for each fuel f and project p:

$$FS_{fp} = \frac{F_{fp}}{P_p^{out}} \quad \left[\frac{\text{MJ fuel}}{\text{MJ product}}\right] \qquad \text{(eq. 11)}$$

$$FS_{f,M} = \sum\nolimits_{p \in M} FS_{fp} \left(\frac{P_p^{bit}}{\sum_{p \in M} P_p^{bit}}\right) \quad \left[\frac{\text{MJ fuel}}{\text{MJ product}}\right] \qquad \text{(eq. 12)}$$

$$FS_{f,IS} = \sum\nolimits_{p \in IS} FS_{fp} \left(\frac{P_p^{bit}}{\sum_{p \in IS} P_p^{bit}}\right) \quad \left[\frac{\text{MJ fuel}}{\text{MJ product}}\right] \qquad \text{(eq. 13)}$$

Here, the sets M and IS represent the sets of mining and in situ projects, respectively.

Figure A-2 represents the aggregated fuel use for a volume-weighted average of refinery input from the oil sands split by production method. Note that the mining value comes to be lower than the in situ value due to the inclusion of the M+Bit pathway.

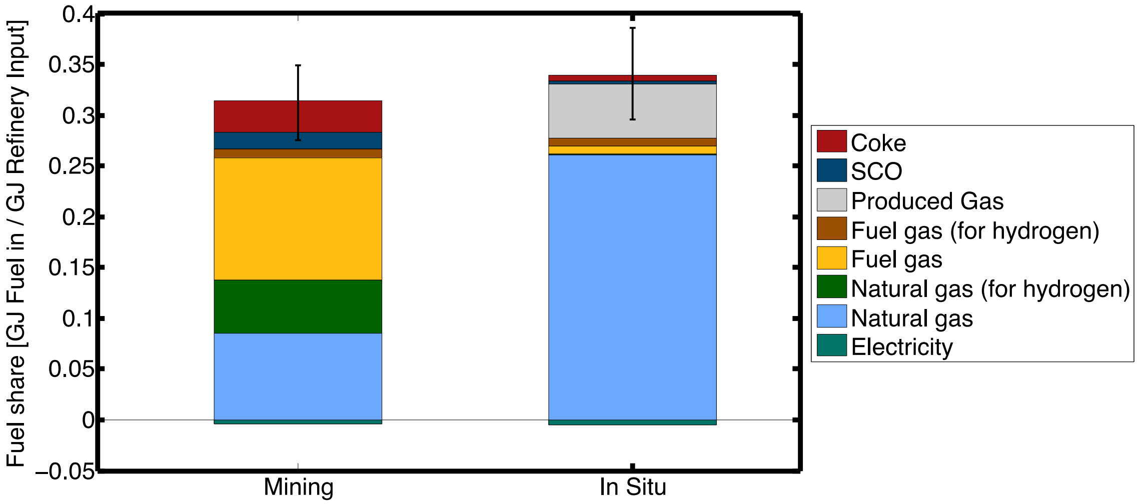

Figure A-2 Fuel shares ($FS_{f,M}$ and $FS_{f,IS}$) for the mining pathway and in situ pathway (Pathway Option 2)

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Appendix B: Terminology

Acronym or Abbreviation	Description
AER	Alberta Energy Regulator (see ERCB below)
AESO	Alberta Electric System Operator
dilbit	diluted bitumen, a refinery input in which bitumen is mixed with a diluent (typically natural gas liquids or naphtha) to reduce its viscosity enough to allow for pipeline flow
CHOPS	cold heavy oil production with sand
CNRL	Canadian Natural Resources Ltd.
CSS	cyclic steam stimulation
ERCB	Energy Resources Conservation Board (now named Alberta Energy Regulator)
FQD	Fuel Quality Directive (European Union)
GHG	greenhouse gas
HHV	higher heating value
IS+Bit	in situ plus bitumen (pathway)
IS+SCO	in situ plus synthetic crude oil (pathway)
JACOS	Japan Canada Oil Sands
LCA	life cycle analysis (or life-cycle assessment)
LCFS	Low Carbon Fuel Standard (California)
LHV	lower heating value
M+Bit	mining plus bitumen (pathway)
M+SCO	mining plus synthetic crude oil (pathway)
MLSB	Mildred Lake Settling Basin
MSV	Millenium, Steepbank, and Voyageur (Suncor)
SAGD	steam-assisted gravity drainage
SCO	synthetic crude oil (refinery input from upgrader pathways)
SOR	steam oil ratio
synbit	Synthetic bitumen, a refinery input blend of synthetic crude oil and bitumen
WTW	well-to-wheels
YPR	yearly progress report

Unit of Measure	Description	Unit of Measure	Description
bbl	barrel(s)	L	liter(s)
Btu	British thermal unit(s)		
		m	meter(s)
d	day(s)	m^3	cubic meter(s)
		Mbbl	million barrels
g	gram(s)	Mg	megagram(s)
gal	gallon(s)	ML	megaliter(s)
GJ	gigajoule(s)	mo	month(s)
		MWh	megawatt-hour(s)
kbbl	thousand barrels		
kg	kilogram(s)		
km^2	square kilometer(s)		

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