White Paper:
Life Cycle Analysis of Greenhouse Gas Emissions from Tar Sands

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Synthetic crude oil and bitumen produced from tar sands (also referred to as oil sands) in Canada represents an increasing fraction of U.S. oil imports.[1] Both increasing oil demand and higher world oil prices have led to the growth of this marginal, unconventional crude oil supply. In 2007, roughly 1.2 million barrels per day of oil from tar sands was produced in Canada, with approximately 75% exported to refineries in the U.S.[2] By 2015, production is expected to grow to between 2 to 4.5 million barrels per day based on several forecasts.[3] The amount of greenhouse gas (GHG) emissions associated with these production levels is estimated to be 90 - 320 MMT CO_2e by 2015, continuing to make tar sands operations one of Canada's largest and fastest growing sources of GHG emissions.[4]

Increasing demand for sustainable, low GHG fuels has also led to increased concern over the life cycle GHG emissions associated with producing tar sands – or emissions associated with the upstream production and downstream combustion of the fuel. Because of the large amounts of upstream energy used to produce tar sands, large amounts of greenhouse gas (GHG) emissions are emitted during the extraction and upgrading of tar sands. In addition, the large geographical extent of surface mining operations and the excavation of land have raised concerns over GHG emissions due to direct land use conversion (LUC) and commensurate loss of biological soil

[1] Tar sands (also known as oil sands) is a mix of sand, water, and clay with naturally occurring bitumen (a heavy hydrocarbon). Note that "oil" from tar sands ("synthetic crude oil") and "bitumen" are different. Synthetic crude oil is upgraded bitumen (i.e. a preliminary refining step to create a crude oil feedstock more similar to conventional crude oil). Bitumen, by contrast, can be also directly transported to refineries with diluent (e.g. naphtha) where it can be process and upgraded further.
[2] Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry*, May 2008. http://www.capp.ca/default.asp?V_DOC_ID=1071
[3] Tyndall Centre for Climate Change Research (May 2007), *Climate Change Policy and Canada's Oil Sand Resources: An Update and Appraisal of Canada's New Regulatory Framework for Air Emissions*, a report for the World Wildlife Fund.
[4] Represents a range of 29 to 46 gCO_2e/MJ fuel (well-to-tank) as tabulated below in Table 2.

carbon. Other environmental and social impacts due to tar sands production, including harm to water supplies, ecosystems, and wildlife, are beyond the scope of this white paper but are discussed elsewhere.[5]

To date, there have been a number of published studies to assess GHG emissions associated with the production of fuels from tar sands.[6] Research performed under Joule Bergerson at the University of Calgary's Institute for Sustainable Environment, Energy, and Economy as well as Heather MacLean at the University of Toronto has also been on-going to assess the life cycle GHG emissions from tar sands. All current reports have identified higher GHG emissions associated with current production of oil from tar sands compared to fuels produced from conventional crude oil pathways.[7]

This white paper reviews the currently available studies on GHG emissions from tar sands production. To the extent possible, the assumptions from the various studies are presented and noted. The purpose of this paper is to provide a comparison of the available academic literature, reports, and data sources in order to provide a basis for discussions between private, public, and government stakeholders on GHG life cycle emissions from tar sands. An evaluation of the data sources and methodologies reveals that there is variability and uncertainty in emissions reported by different studies specifically for the extraction and upgrading process stages. Some of the variation, particularly at the extraction and upgrading stages, appear to reflect inconsistencies in accounting of direct and indirect emission sources, sources of data, and the particular process pathway represented. However, on an entire "well-to-wheels" basis, these differences represent a smaller overall fraction of the fuel lifecycle GHG emissions.

Uncertainties also remain regarding both the methodology and magnitude of GHG emissions associated with land use conversion, loss of soil carbon, as well as capital and construction-related emissions. Improved reporting, greater transparency in data, better accounting of both indirect and direct emissions, and expansion of the study boundaries would allow life cycle estimates to be improved upon and more easily compared. While none of these issues are unique to tar sands alone, tar sands is receiving considerable attention partly because of the potential size of the bitumen reserves, the large growth rate of the industry, and the current and expected magnitude of the environmental impacts.

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[5] NRDC (2007), *Driving It Home: Choosing the Right Path for Fueling North America's Transportation Future,* WWF (July 29, 2008), *Unconventional Oil: Scraping the Bottom of the Barrel?*; R. Schneider, S. Dyer (August 2006), *Death by a Thousand Cuts: Impacts of In Situ Oil Sands Development on Alberta's Boreal Forest,* The Pembina Institute/ Canadian Parks and Wilderness Society; "Canada's Boreal Forest: Part of the Global Climate Change Solution,"

[6] J. Bergerson and D. Keith, (2006) "Life Cycle Assessment of Oil Sands Technologies," Paper No. 11 of the Alberta Energy Futures Project, University of Calgary, "November 2006; Larsen, Robert; Wang, Michael;, Wu, Ye; and Vyas, Anant, *World Resources Review*, Vol. 17 (2), 220-242; McCulloch, Matthew, Raynolds, Marlo, and Wong, Rich, "Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands," October 2006, The Pembina Institute; Natural Resources Canada, "@007 Crude Oil Production Update for GHGenius," prepared by $(S\&T)^2$ Consultants Inc. March 30, 2007; Flint, Len, "Bitumen Recovery Technology: A Review of Long Term R&D Opportunities," LENEF Consulting, LTD.

[7] Bergerson and Keith (2006) provide a review of some of the current GHG emission values publically available.

Literature Review

The authors conducted a review of existing estimates for the GHG emissions associated with production of tar sands. This review discusses both the magnitude and ranges of these estimates. The literature is divided into several major categories based on their sources of data -- primary data from operators themselves, primary analyses from third party sources, government publications, and other academic and technical reports. In general, the estimates of GHG emissions for tar sands are typically either based on top-down estimates (i.e. derived from regional or national data) or bottom-up estimates (i.e. derived from an inventory of sources for specific projects).

Primary Operator Data

Information on emissions from tar sands extraction and upgrading operations are available from project applications and accompanying Environmental Impact Statements (EIS),[8] project emissions data,[9] submissions to the Voluntary Challenge & Registry (VCR), as well as industry reports.[10] Project applications typically provide estimates of the proposed site emissions. Typically, the reporting and accounting method for site emissions can differ from company to company. In addition, emissions typically represent direct site emissions as opposed to indirect emissions. These indirect emissions can be attributed, for instance, to process inputs (natural gas, electricity) that are produced off-site. The Pembina Institute has collected and compiled information from numerous project applications, reconciling differences in reporting to include both direct and indirect emissions.[11]

Primary Third Party Analysis

In addition to these publicly available sources, several third party publications have been developed from either unpublished data or data obtained through confidentiality agreements with the tar sands operators. One widely cited study by McCann and MacGee (1999) relies on production data from surface mining operators. The authors developed estimates of life cycle GHG emissions by using an in-house, refinery-and-upgrading emissions spreadsheet model.[12] The Canadian Industrial Energy End-use Data and Analysis Center (CIEEDAC) at Simon Fraser University has also published several reports using similarly obtained data, most notably John Nyboer's 2003 publication "A Review of Energy Consumption in Canadian Oil Sands Operations, Heavy Oil Upgrading 1990, 1994 to 2001."[13] This report involved coordination between individual operators and Statistics Canada to develop a consistent dataset of energy

[8] See, for instance: CNRL 2002, Horizons Oil Sands Project Application for Approval
[9] See, for instance: Suncor Energy 2005, Voyageur Project Environmental Impact Assessment Volume 3 or Syncrude Corporation 2004, "An Action Plan for Reducing Greenhouse Gas Emissions."
[10] See, for instance: CAPP 2003, Calculating Greenhouse Gas Emissions.
[11] See for instance: Pembina Institute (2008) *Under-Mining the Environment: The Oil Sands Report Card.* Appendix, http://ww.oilsandswatch.org/pub/1571
[12] McCann, T. and P. Magee. 1999. "Crude Oil Greenhouse Gas Life Cycle Analysis Helps Assign Values for CO2 Emissions Trading." Oil & Gas Journal. Vol. 97. Iss. 8. Pp. 38-43.
[13] CIEEDAC. 2003. "A Review of Energy Consumption in Canadian Oil Sands Operations, Heavy Oil Upgrading 1990, 1994 to 2001."

consumption and emissions. Reports by Len Flint of LENEF Consulting, which relies on operator data and technical industry knowledge, could also be placed in this category as well. [14]

Government and Industry Publications
Numerous estimates of GHG emissions from tar sands are based on a handful of government and industry publications. These publications are, in turn, based on a combination of publicly available operator data as well as private data obtained through confidentiality agreements. The 2004 *Oil Sands Technology Roadmap* by the Alberta Chamber of Resources (Alberta 2004), for instance, relies heavily on LENEF and McCann values as well as in-house calculations. The National Energy Board's (NEB) 2004 report entitled "Canada's Oil Sands: Opportunities and Challenges to 2015" provides emissions estimates but does not provide detail on how these estimates were developed. The NEB report appears to rely heavily on consultation with various operators and industry trade groups. Natural Resources Canada has also published a number of relevant reports, including the "2008 Crude Oil Production Update for GHGenius" which relies on Canadian Association of Petroleum Producers (CAPP) reports, the CIEEDAC report mentioned above, and their own 2006 *Canada's Energy Outlook*. GHGenius is a lifecycle assessment model developed by Natural Resources Canada.[15]

Secondary Sources: Academic and Technical Reports
Finally, there also exist a number of reports intended for academic, technical, and general audiences which either contain emissions factors themselves or from which emissions factors can be estimated.

Of particular note in this category are two reports published by Brandt and Farrell (2007) and Farrell and Sperling (2007).[16] The emission estimates from these reports rely on 2004 Syncrude data, National Energy Board estimates for the production component of the pathway, and Wang et al. (1999) for the refining component.[17] A later study by Larsen and Wang (2005) relies on industry level data from the Alberta Oil Sands Roadmap to produce top-down, average estimates of the energy use from tar sands extraction and upgrading.[18] This information is used to provide input parameters for the Argonne National Laboratory's life cycle emissions model (GREET), the outputs of which are presented below. Another set of estimates is available from Furimsky (2003) which does not rely on actual plant data but utilizes a simplified process flow sheet of a tar sands plant. Information from published engineering literature was then used to characterize the plant processes and to make estimates of GHG emissions.[19] Several additional reports are

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[14] See, for instance: Flint 2004, "Bitumen & Very Heavy Crude Upgrading Technology" and Flint 2005, "Bitumen Recovery Technology: A Review of Long Term R&D Opportunities"
[15] http://www.ghgenius.ca/
[16] Brandt, A.R. and A.E. Farrell (2007). "Scraping the bottom of the barrel: greenhouse gas emission consequences of a transition to low-quality and synthetic petroleum resources." *Climatic Change*, 84:241-263.
[17] Wang, M., C. Saricks, et al. (1999). Effects of Fuel Ethanol Use on Fuel-Cycle Energy and Greenhouse Gas Emissions. Argonne, IL, Center for Transportation Research, Energy Systems Division, Argonne National Laboratory: 39.
[18] Larsen, R; Wang, M; Wu, Y; Vyas, A; Santini, D; and Mintz, M, "Might Canadian Oil Sands Promote Hydrogen Production for Transportation? Greenhouse Gas Emission Implications of Oil Sands Recovery and Upgrading, *World Resource Review*, Vol 17. No. 2, pp 220 -242.
[19] Furimsky, E. Emissions of Carbon Dioxide from Tar Sands Plants in Canada. Energy & Fuels. 2003. Vol.17. pp. 1541-1548.

available which build of these and other studies, and in doing so either provide their own estimates or provide summaries of other sources.[20]

There are also a number of tar sands reports intended for general public consumption. These include reports from the Pembina Institute such as “Carbon Neutral 2020: A Leadership Opportunity in Canada’s Oil Sands” [21] “The Climate Implications of Canada’s Oil Sands Development,”[22] as well as from the World Wildlife Fund “Climate Change Policy and Canada’s Oil Sand Resources: An Update and Appraisal of Canada’s New Regulatory Framework for Air Emissions.”[23]

It is important to note that while all of the sources discussed above offer substantive contribution to the tar sands emissions debate, full life-cycle (or full upstream) emissions factors are available in only a few of the analyses. Table 1 summarizes those sources.

Upcoming work by Professor MacLean at University of Toronto and Professor David Keith at the University of Calgary should also provide a more accurate and richer understanding of the life cycle emissions associated with tar sands production. Two reviews of current life cycle estimates for tar sands have been published or are forthcoming.[24] Both groups are currently applying hybrid Economic Input-Output (EIO) approaches with traditional Life Cycle Assessment (LCA) methods. The EIO-LCA approach utilizes economic input-output (EIO) models to assess indirect effects from fuel production on the economy and linking these changes to emission factors.

[20] See, for instance, Bergerson J. and D. Keith 2006, “Life Cycle Assessment of Oil Sands Technologies” and Larson, R. et al 2005, “Might Canadian Oil Sands Promote Hydrogen Production for Transportation.”

[21] McCulloch, M., M. Raynolds, and R. Wong. 2006. “Carbon Neutral 2020: A Leadership Opportunity in Canada’s Oil Sands.” The Pembina Institute.

[22] Bramley, M., D. Neabel, and D. Woynillowicz. 2005. “The Climate Implications of Canada’s Oil Sands Development.” The Pembina Institute.

[23] Footitt, A. 2007. “Climate Change Policy and Canada's Oil Sand Resources: An Update and Appraisal of Canada's New Regulatory Framework for Air Emissions.” Tyndall Center for Climate Change Research, prepared for WWF.

[24] "McKellar, J., Charpentier, A.D., Bergerson, J.A., MacLean, H.L., 2008, "A Life Cycle Greenhouse Gas Emissions Perspective on Liquid Fuels from Canadian and U.S. Unconventional Fossil Sources", *International Journal of Climate Change*, Accepted July 2008; and J. Bergerson and D. Keith (2006). “Life Cycle Assessment of Oil Sands Technologies.” Paper No. 11 of the Alberta Energy Futures Project. University of Calgary.

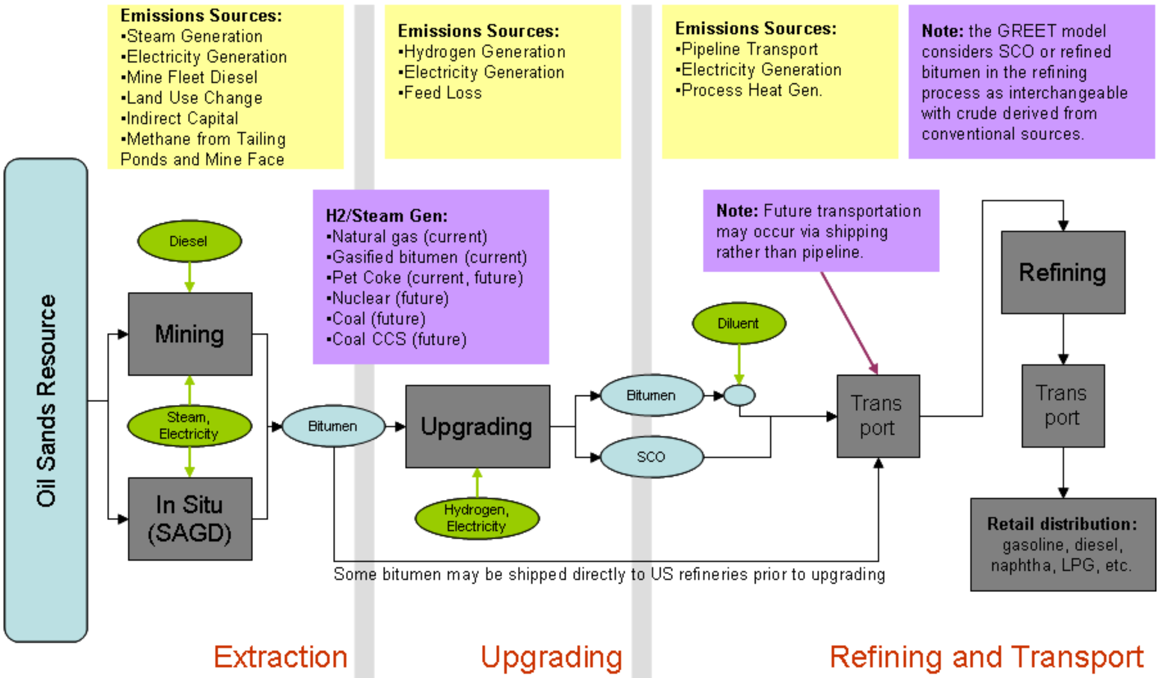
Table 1: Current studies with full well-to-wheels or source-to-wheels emission factors.

Resource	Data Sources
Alberta Chamber of Resources 2004: Oil Sands Technology Roadmap (OSTR)	LENEF, McCann, Internal
McCann 1999: Crude Oil GHG LCA Helps Assign Values for CO2 Emissions Trading	Various, Unpublished Data
Nyboer 2003: A Review of Energy Consumption in Canadian Oil Sands Operations	CIEEDAC Industry Surveys
Natural Resources Canada 2007: Crude Oil Production Update for GHGenius	NRCan 2006 Energy Outlook, Syncrude/Suncor
Furimsky 2003: Emissions of CO2 from Tar Sands Plants in Canada	Various
Brandt & Farrell 2007: Scraping the Bottom of the Barrel Sperling & Farrell 2007: A Low Carbon Fuel Standard for California	Canada’s National Energy Board 2004, Suncor Progress Report 2003
Flint 2005: Bitumen and Very Heavy Crude Upgrading – Long Term R&D… Flint 2004: Bitumen & Very Heavy Crude Upgrading Technology	Oil Sands Technology Roadmap, Internal
Pembina 2005: Oil Sands Fever Pembina 2005: Implications of Canada’s Oil Sands Development	Suncor, Academic Papers
Larsen and Wang 2005, Might Canadian Oil Sands Promote Hydrogen Production for Transportation? Greenhouse Gas Emission Implications of Oil Sands Recovery and Upgrading	Alberta Chamber of Resources 2004

Estimates for GHG Emissions Associated with Oil Sands Production

The different estimates from currently available reports and life cycle analysis models are presented and compared below. Two major pathways, surface mining and in-situ recovery, are currently used for extraction of bitumen in Canada as shown in Figure 1. The majority of upstream emissions are associated with the extraction and upgrading stages, both of which involve energy intensive processes. Natural gas is currently the predominant process fuel used to produce steam and hot water for extraction as well as hydrogen gas for upgrading of bitumen and electricity for on-site operations. Different feedstock may be increasingly used in the future to produce hydrogen and steam including coal gasification, nuclear energy, and petroleum coke. Petroleum coke is currently used in some facilities. Note that GHG emissions will vary depending on the source and process used to generate steam and hydrogen as discussed in Larsen and Wang (2005).

Figure 1: Process stages for production of fuel from oil/tar sands. Information drawn from Elgowainy (2008),[25] Larsen & Wang (2005), Flint (2004), and from Alberta (2004).



Most studies to date have focused on the extraction and upgrading emissions associated with tar sands oil production, relying on either primary operator data (Pembina 2006, NRCan 2007), private-client data (McCann 1999) or government/industry reports (Larsen & Wang 2005; Nyboer 2003; Flint 2005). In general, the scope differs between each study. For instance, some studies are not necessarily life cycle based but focused on an emissions inventory of the extraction and upgrading process (e.g. Pembina 2006, Flint 2005). By contrast, others incorporate a full fuel cycle analysis and use a life cycle model (Larsen & Wang 2005, NRCan 2007, McCann 1999). In some cases, operators may not report indirect emissions (e.g. emissions associated with production of natural gas) or may allocate emissions differently depending on the level of facility integration (e.g. mining and upgrading at the same facility). In general, the studies reflect both incorporation of bottom-up estimates (e.g. Pembina 2006) and reliance on top-down estimates (e.g. Larsen & Wang 2005).

A comparison of the results from currently available studies is presented below in Table 2. The results are presented on a common basis, grams CO_2 per mega joule (g CO_2e/MJ, lower heating value). When available, estimates are also shown for other upstream production stages. The factors used to convert values to the common basis (MJ) are provided in the appendix. Also included in the appendix are a list of specific assumptions used in the GREET model and GHGenius model

[25] Elgowainy, Amgad. 2008. "Introduction to GREET 1.8 Excel Model." Presentation to the GREET User Workshop, Sacramento, CA. March 20, 2008.

Table 2: Comparison of studies and model results for tar sands. Units are in terms of grams CO_2-equiv per MJ finished fuel, lower heating value. SAGD and CSS are in-situ recovery methods and stand for Steam Assisted Gravity Drainage and Cyclic Steam Stimulation, respectively.

(a) List of Studies or Models, Cases Represented, and General Sources of Data

	Case(s) Represented	Lifecycle Model Used	Sources of Data
GREET 1.8b	2010 Analysis Year (Gasoline), Mining + Upgrading; In-Situ and Upgrading	GREET Ver. 1.8b	OSTR (2004), Wang (2005)
NRCan (2008)	2008 Analysis Year (Gasoline), Mining, SAGD, CSS with Standalone or Refinery Upgrading	GHGenius Ver. 3.13	Project applications and reports, CAPP (2008)
Pembina (2008)	Includes ranges for current and future operations	Not applicable	Project applications and reports
Flint (2005)	Use of Natural Gas Process Fuel and Petroleum Coke	Not applicable	Not specified, Suncor, Syncrude referenced
Furimsky (2003)	Use of Fluid Coking and Delayed Coking Processes	Not applicable	Plant data N/A; evaluation based on engineering literature
McCann (1999)	2005 Analysis Year (Forecasted in 1999)	Proprietary Model	Suncor, Syncrude averages, some operator data

(b) Surface mining recovery

	Cases	Extraction	Upgrading	Subtotal	Feedstock Transport	Refining	Fuel Distribution	Total: Source to Pump
GREET 1.8b	Mined Bitumen & Standalone Upgrader	5.1	8.7	13.8	3.0	11.5	0.5	28.7
NRCan (2008)	Mined Bitumen & Refinery Upgrading	6.6		6.6	0.3	25.1	0.8	32.9
	Mined Bitumen & Standalone Upgrader	20.3		20.3	0.3	13.1	0.9	34.5
	Mined Bitumen & Integrated Upgrader	20.6		20.6	0.3	13.1	0.9	34.9
Pembina (2008)	Various Projects	4.1 - 7.7	2.4 - 16.2	6.3 - 23.9	-	-	-	-
Flint (2005)	Natural Gas Process Fuel	6.1	7.4	13.5	-	-	-	-
	Coke Process Fuel	7.8	13.9	21.7	-	-	-	-
Furimsky (2003)	Fluid Coking	13.2 - 15.4		13.2 - 15.4	-	4.2	-	-
	Delayed Coking	25.1 - 40.1		25.1 - 40.1	-	4.2	-	-
McCann (1999)	Mined Bitumen and Integrated Upgrader	19.6		19.6	1.5	15.6	-	-

(c) In-situ recovery

	Cases	Extraction	Upgrading	Subtotal	Feedstock Transport	Refining	Fuel Distribution	Total: Source to Pump
GREET 1.8b	In-Situ & Standalone Upgrader	13.2	4.6	17.8	3.0	11.5	0.5	32.8
NRCan (2008)	In-Situ (SAGD) and Refinery Upgrading	13.1		13.1	0.3	26.6	0.9	40.9
	In-situ (CSS) & Refiner Upgrading	11.9		11.9	0.3	26.4	0.9	39.4
	In-Situ (SAGD) & Standalone Upgrader	30.3		30.3	0.3	14.1	0.9	45.7
	In-Situ (CSS) & Standalone Upgrader	28.5		28.5	0.3	14.0	0.9	43.7
Pembina (2008)	Various Projects	5.9 - 28.0	2.4 - 16.2	8.2 - 44.2	-	-	-	-
Flint (2005)	Natural Gas Process Fuel	11.0	7.0	18.0	-	-	-	-
	Coke Process Fuel	16.5	14.3	30.8	-	-	-	-

For oil sands from surface mining, the following observations can be made regarding Table 2b:

- The results from GHGenius (ver. 3.13) are generally higher across the board compared to GREET (ver. 1.8b). Note that in the previous version of GHGenius (ver. 3.12b), surface mining emissions were slightly below that of the GREET model. The increase in GHGenius ver. 3.13 values are due to significant updates as documented in NRCan (2008) and summarized below.
- The ranges reported by the Pembina Institute, based on project applications from operators, generally encompass the ranges from the engineering and top-down estimates. In general estimates appear consistent with the ranges from the Pembina Institute. The project application data obtained by Pembina for upgrading may not include indirect emissions. Based on information reported by the Shell Scotford Upgrader Projects, the indirect emissions may add an additional 17 – 32% to the direct emission values shown for upgrading.[26]
- The Flint (2005) estimates show generally larger extraction and upgrading emissions when petroleum coke is used to substitute for natural gas. This result is consistent with a study by Larsen and Wang (2005) showing larger emissions as operators move from natural gas to petroleum coke. The results from Flint (2005) are also consistent with a GREET 1.8b model run using petroleum coke for hydrogen and steam production (not shown here).
- McCann (1999) values generally show higher emissions associated with extraction and upgrading compared to results from current versions of GREET and GHGenius. While it is difficult to assess the reasons for these differences, the results may reflect use of Syncrude and Suncor specific forecasts and are generally consistent with the Pembina Institute reports for both producers (Table 3a).

For oil sands produced from in-situ recovery methods, the following observations can be made regarding Table 2c:

- Again, results from GHGenius (ver. 3.13) are generally higher for the different in-situ pathways compared to the single pathway represented by GREET 1.8b.
- Estimates reported by Pembina (again based mainly on project application data) generally encompass a larger range than for mining operations. This range may reflect the large number of proposed operations versus actual operations, the range of process fuels being considered, different recovery methods being utilized, and differences in reservoir characteristics.
- The Flint (2005) study again shows similar differences between using petroleum coke versus natural gas for process heat and hydrogen generation.
- McCann (1999) estimates for the in-situ process were not available.

[26] NRCan (2008), *2008 GHGenius Update,* Prepared for Natural Resources Canada, prepared by $(S\&T)^2$ Consultants Inc. August 15, 2008. p. 14.

GREET and GHGenius

The GREET model (version 1.8b) and GHGenius (version 3.13) results are shown below in Figures 2. Internal runs using a previous version of GHGenius (version 3.12b) were also conducted, since version 3.13 was not available until this white paper was largely completed. Results from the NRCan (2008) report are shown however using GHGenius version 3.13.

In general, GHGenius 3.13 estimates are higher than those from GREET 1.8b (assuming the default inputs). Note that results from the previous version of GHGenius (3.12b) largely were more similar to those of GREET 1.8b. The differences with the latest, current version of GHGenius (3.13) can be explained based on some significant updates that were made since the earlier versions. These updates include changes to the underlying data sources used as well as the addition of a greater number of tar sand pathways.

Previous versions of GHGenius used information from CAPP (2003) to represent the in-situ process (bitumen) and CIEEDAC (2003) data for the mining process (synthetic crude oil).[27] The CAPP (2003) report provides estimates of the energy intensity required to produce bitumen (in-situ) but did not provide detail on the types of input energy used, so that some assumptions based on industry submissions were made. For earlier versions of the model, information from Imperial Oil's submission in 2003 to the Voluntary Challenge and Registry (VCR) was used to estimate the types of input energy. Similarly, the CIEEDAC (2003) report provided energy intensity information to calculate the energy and carbon associated with producing synthetic crude oil via the mining process. The CIEEDAC report is based on survey data and breaks down the information based on type of energy use. The latest CIEEDAC data set was for the year 2001.

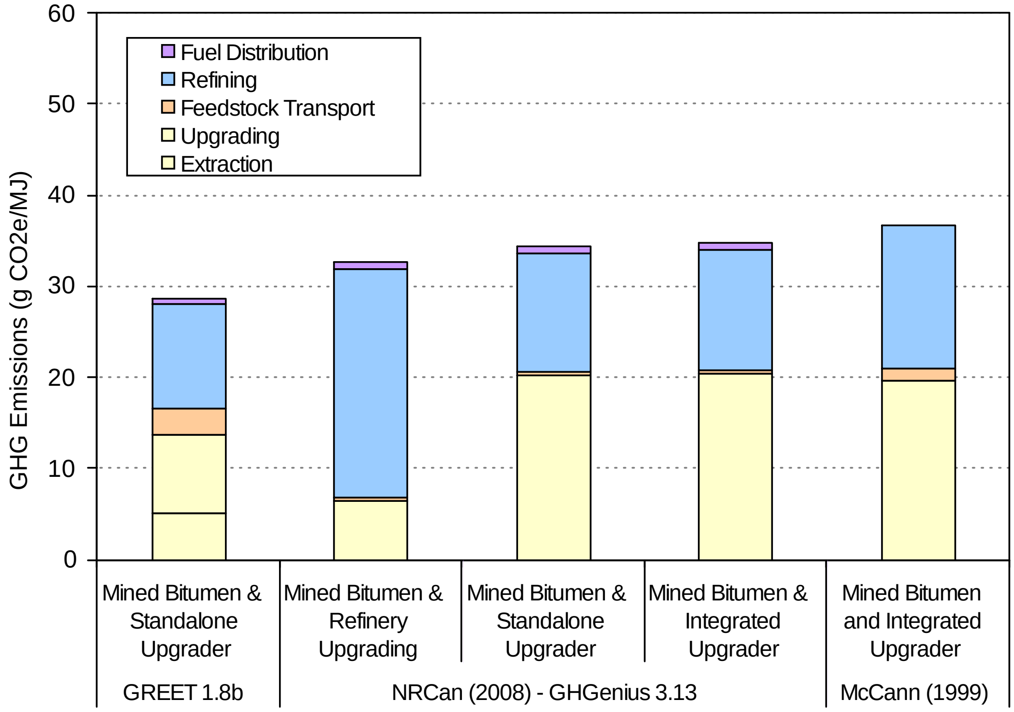
As documented in NRCan (2008), the current GHGenius 3.13 has been updated to include additional oil sands pathways. Three pathways have been included to produce bitumen by using mining methods, Steam Assisted Gravity Drainage (SAGD), or Cyclic Steam Stimulation (CSS). SAGD and CSS both represent in-situ methods of bitumen recovery. The model also now allows for three subsequent process routes for the bitumen – (1) diluent bitumen being processed and upgraded at the refinery, (2) bitumen upgraded in a stand-alone upgrader and sent to the refinery as synthetic crude oil (SCO), and (3) bitumen being recovered and upgraded at an integrated facility and sent to the refinery as SCO.

The data sources used in GHGenius 3.13 to estimate process fuel consumption appear to be more recent and based on available bottom-up, project application data. For the mining operations, the default values are based on three Environmental Impact Assessments (EIAs) for the Shell Jackpine operations and Total Joslyn mine. Fugitive emissions from tailing ponds and the mine face are based on the Total operations. An input for soil and biomass carbon loss is also included in the GHGenius model. The current default inputs are based on information from Suncor and Syncrude annual reports and appear to represent 0.2% of total source-to-tank emissions. However, as discussed below in the land use change section, these impacts may add an additional 14% to total source-to-tank emissions depending on the assumptions and methodology used to account for CO_2 emissions over time.

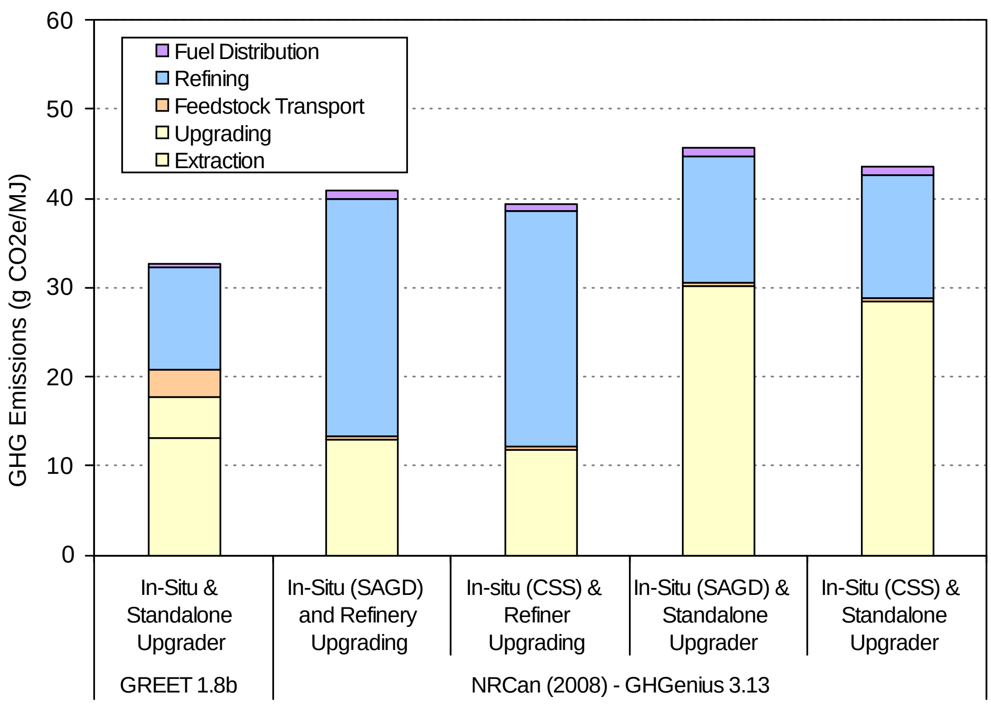
[27] For more detail, see "Documentation for Natural Resources Canada's GHGenius Model 3.0," Prepared for Natural Resources Canada, Prepared by (S&T)^2 Consultants Inc., September 15, 2005.

Figure 2. Comparison of Source-to-Tank GHG Emissions for Oil Sands Extracted via (a) Surface Mining and (b) the In-Situ Process. Results for GREET (version 1.8b), GHGenius (version 3.13), and McCann (1999) are shown.

(a) Surface Mining Results



(b) In-Situ Process Results



In-situ pathways and data are now further broken down by CSS or SAGD methods in GHGenius 3.13. For CSS, information from Imperial Oil continues to be used together with information from Canadian Natural Resources' Wolf Lake Project. NRCan (2008) identified both these operators as the two major producers of CSS bitumen. Venting and flaring emissions were based on the CAPP (2004) inventory report. For SAGD, information on the steam-to-oil ratios from nine different projects were used. The results for the in-situ production values were reported by NRCan (2008) to be consistent with the CAPP (2007) Stewardship Report.[28]

Newer versions of GHGenius account for the crude oil properties in the model by applying linear relationships between API gravity, carbon content, sulfur content, and energy content. Because of this differentiation, bitumen sent to the refinery requires greater energy at the refinery to process compared to a synthetic crude oil already upgraded at a stand alone upgrader. This is in contrast to the default assumptions in GREET 1.8b, which assumes that all upgrading occurs upstream of the refinery so that synthetic crude oil is treated identically to other conventional crude oils at the refinery. The differences in the fuel production and feedstock extraction/upgrading stages in GHGenius are primarily due to the different process pathways considered.

By contrast, assumptions for GREET 1.8b are largely based on a 2004 Alberta Chamber of Resources report, "Oil Sands Technology Roadmap: Unlocking the Potential" (OSTR), as explained in Larsen and Wang (2005). The methodology relies largely on a top-down approach by using the report's energy intensity values for natural gas used for mining or in-situ production, for H_2 upgrading, and for upgrading process fuel. Engineering assumptions about the conversion efficiencies of natural gas to hydrogen were made by Larsen and Wang (2005). However, the data provided by OSTR was developed internally by Alberta Chamber of Resources and not published. It is unclear what assumptions or project application data was used for the aggregated estimates or the degree to which this data has been updated since the time of the report. In addition, consumption information for natural gas is not attributed to a particular year but referenced as "today" and "future," making it difficult to assess the source information.

Pembina Institute Estimates Using Primary Operator Data

Currently there are over 80 oil sand projects in Alberta that are active.[29] Project information compiled by the Pembina Institute (2008) for a large number of operations is shown below in Table 3. The data is based on project applications/environmental assessments for current and proposed projects. The reported data from companies tend to be projected inventories of the direct emissions that occur on-site. Indirect emissions that are produced off-site such as from natural gas production or electricity generation are sometimes included but in many instances are not. Differences in the reporting and accounting methodology make direct comparisons difficult.

The Pembina assessment attempts to reconcile these differences in the reported information by applying emission factors for indirect emissions occurring offsite, such as for natural gas or electricity generation. The emission sources accounted for include the following activities:

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[28] CAPP (2008). *2007 Stewardship Report*, Canadian Association of Petroleum Producers. http://www.capp.ca/default.asp?V_DOC_ID=19
[29] NRCan (2008).

mining and mine-face, processing units, tailing ponds (methane), on or offsite electricity production, heating, fugitive emissions, and offsite natural gas production. Table 3a and 3b show the compiled data for both mining and in-situ operations. Table 3c displays the GHG emissions reported by upgraders. Unfortunately, indirect emissions for upgrading do not appear to be reported out so that Table 3c represents direct emissions. However, based on information reported by the Shell Scotford Upgrader Projects, the indirect emissions may add an additional 17 – 32% to the direct emission values shown.[30] In addition, these lists provided in Table 3 are not exhaustive and may aggregate some projects.

Comparisons of projects can be challenging using the site inventory approach because of variations in (1) the level of integration for a particular operator, (2) the upgrading energy being a function of the initial bitumen characteristics, and (3) differences in the level of detail reported by companies. Estimates between specific project phases can also differ. For instance, emissions for the Petro Canada Fort Hills Sturgeon Upgrader Phase 2/3 are larger than Phase 1 due to the inclusion of a gasifier for hydrogen production. A detailed process-based analysis that tracks the bitumen from recovery through the various stages of processing would obviously allow for direct comparisons to be made.

Table 3: Emission estimates from current and proposed projects. Emissions are mainly based on inventories from project applications/environmental impact statements. This list does not reflect all current or proposed projects. (g CO_2/ MJ fuel, lower heating value). Source: Pembina Institute (2008) *Under-Mining the Environment: The Oil Sands Report Card.* http://ww.oilsandswatch.org/pub/1571

(a) Mining Operations[31]

Company	Project Name	kg CO2eq/bbl bit	g CO2eq/MJ bit
Albian Sands Energy Inc	*Muskeg Existing*	24.4	4.2
	Muskeg Expansion	44.4	7.7
Canadian Natural	Horizon	23.3	4.1
Imperial Oil Resources Ventures Ltd.	Kearl Phases 1, 2, & 3	40.4	7.0
Petro-Canada Oil Sands Inc.	Fort Hills	40.5	7.0
Shell Canada Ltd.	Jackpine Phase 1	36.1	6.3
Suncor Energy Inc.*	*Current Operations*	95.1	16.6
Syncrude Canada Ltd*.	*Current Operations*	126.6	22.0
Synenco Energy Inc.	Northern Lights Phases 1 & 2	41.6	7.2
Total E&P Canada	Joslyn North Mine Phases 1 & 2	39.9	6.9
RANGE (excluding Suncor and Syncrude)		**23.3 - 44.4**	**4.1 - 7.7**

* Suncor and Syncrude include both the extraction and upgrading emissions and are not directly comparable with other operations. The Suncor information includes mining, in-situ, and upgrading activities. The Albian Sands (Muskeg Existing) operation includes indirect emissions associated with upstream natural gas production.

[30] NRCan (2008), *2008 GHGenius Update*, Prepared for Natural Resources Canada, prepared by $(S\&T)^2$ Consultants Inc. August 15, 2008. p. 14.
[31] Pembina Institute (2008) *Under-Mining the Environment: The Oil Sands Report Card.* http://ww.oilsandswatch.org/pub/1571

(b) In-Situ Operations. Most projects are proposed and not currently operating.[32] Source: Personal communication, Pembina Institute. April 14, 2008. (This is not an exhaustive list. The data is mainly compiled from project applications/environmental assessments).

Company	Project Name	kg CO2eq/bbl bit	g CO2eq/MJ bit
BlackRock Ventures	Orion	101.9	17.7
CNRL	Primrose East	161.0	28.0
	Wolf Lake/ Primrose	103.9	18.1
ConocoPhillips	Surmont - Phase 1 & 2	109.6	19.1
Deer Creek Energy (now Total E&P)	Joslyn Phase 2	75.3	13.1
Deer Creek Energy (now Total E&P)	Joslyn Phase 3	39.5	6.9
Devon Energy	Jackfish	65.7	11.4
Encana	Christina Lake Phase 1A	49.1	8.5
Husky Energy	Sunrise	60.8	10.6
	Tucker Lake	71.4	12.4
Imperial Oil Resources Ventures Ltd.	Cold Lake	81.7	14.2
	Nabiye	84.5	14.7
Japan Canada Oil Sands Inc.	Hangingstone	81.3	14.2
Opti/Nexen	Long Lake	-	-
Petro-Canada Oil Sands Inc.	MacKay River Current	34.0	5.9
	MacKay River Expansion	34.3	6.0
	Meadow Creek	105.0	18.3
Shell Canada Ltd.	Peace River	125.0	21.8
Suncor Energy Inc.	Firebag	-	-
RANGE		**34.0 - 161.0**	**5.9 - 28.0**

(c) Upgrading Operations.[33] Sources include Total E&P Canada (2007), *Integrated Application for Approval of the TOTAL Upgrader*, Volume 1, pp 6-13; Petro Canada (2006), *Sturgeon Upgrader Application Documentation*, Volume 1, Section 6, Table 6-3, p. 7. http://www.petro-canada.ca/en/about/589.aspx

Company	Project Name	kg CO2eq/bbl bit	g CO2eq/MJ bit
Total E&P Canada	Total E&P Canada	50.7	8.8
Shell Canada Ltd.	Scotford Base Plant	33.6	5.8
	Scotford Base + Approved Expansion	32.9	5.7
	Scotford Upgrader 2	60.9	10.6
Petro Canada	Fort Hills Sturgeon Upgrader Phase 1	40.7	7.1
	Fort Hills Sturgeon Upgrader Phase 2/3	62.6	10.9
BA Energy Inc.	Heartland Upgrader	14.0	2.4
North West Upgrading Inc.	North West Upgrader	92.8	16.2
RANGE		**14.0 - 92.8**	**2.4 - 16.2**

Direct Land Use Change and Loss of Biological and Soil Carbon

The surface mining process is known to require the large-scale disturbance of Northern Alberta ecosystems due to (1) the removal of overburden, (2) resulting loss of biomass and soil removal, and (3) associated infrastructure such as roadways and facilities. A presentation by Jordaan (2008) from the University of Calgary also suggests that in-situ tar sands development leads to significant land disturbances once the additional fragmentation from off-site, natural gas

[32] Personal communication, Pembina Institute. April 14, 2008. (as noted, this table is not exhaustive and the data is compiled from project applications/environmental assessments).

[33] Total E&P Canada (2007), *Integrated Application for Approval of the TOTAL Upgrader*, Volume 1, pp 6-13. Also see Petro Canada (2006), *Sturgeon Upgrader Application Documentation*, Volume 1, Section 6, Table 6-3, p. 7. http://www.petro-canada.ca/en/about/589.aspx

facilities are taken into account.[34] Accounting for these diffuse sources of land fragmentation results in similar, or even greater, areas disturbed for tar sands from in-situ methods compared to mining. Because the distributions of these disturbances are diffuse, they have largely been ignored to this point. An estimate of the contributions of these disturbances to GHG emissions was reported to be forthcoming.

By comparison, an initial estimate of the biological and soil carbon footprint associated with oil sands mining is provided by a white paper from the Canadian Boreal Initiative (CBI) and Canadian Ducks Unlimited (DUC) (2008).[35] Their analysis assessed the spatial scale of the disturbance by analyzing historical and current satellite imagery as well as aerial photographs. Approximately 453 km^2 of area was estimated to have been disturbed by surface mining, an estimated 75% of which was largely composed of surface mines or settling ponds. Three major categories of terrestrial ecosystems were identified for Alberta's boreal region: carbon-rich peatlands, mineral wetlands, and upland forests. Carbon emission factors were used based on assessments in literature.[36] Table 4 below summarizes some of the results.

Table 4: Estimates of Disturbed Area and Soil Carbon (CBI/DUC study) – Surface Mining

Land	% of disturbed area	tonne C/hectare
Peatlands	36%	1,347
Mineral Wetlands	19%	200
Upland Forests	44%	171
Weighted Avg	100%	601

71	hectares disturbed/million cubic meter produced

The cumulative production of surface mining oil sands was estimated based on government data so that an average soil carbon emissions factor could be calculated per unit of production. Approximately 71 hectares was estimated to be removed per million m^3 of bitumen/SCO produced.

Based on these estimates, the CBI/DUC analysis estimates that the loss of biological soil carbon equates to 0 to 4.0 gCO2e/MJ. This amounts to roughly 0 to 14% of the total source-to-tank GHG emissions. The higher end of the estimates represents all the biological and soil carbon removed from these areas and being emitted to the atmosphere. The lower end represents the possibility that all the land is eventually reclaimed and restored to conditions equivalent to the original ecosystems. This lower end, however, is considered unlikely since wetlands, in particular, will be difficult to restore and the reclaimed wetlands will not have deep layers of

[34] Sarah Jordaan, David Keith (2008), "Life-cycle eco-impacts of oil sands extraction in Alberta," Seminar. U.C. Davis Institute for Transportation Studies, September 28.
[35] "Biological Carbon Emission Intensity of Oil Sands Mining," August 2008, Ducks Unlimited Canada and Canadian Boreal Initiative.
[36] The cited literature included: Gorham, E. 1991. Northern peatlands: role in the carbon cycle and probable response to climatic warming. Ecological Applications 1: 182-195; W.A. Kurz and M.J. Apps. 1999. A 70-year retrospective analysis of carbon fluxes in the Canadian forest sector. Ecological Applications 9(2): 526-547; and E.A. Johnson and K. Miyanishi. 2008. Creating new landscapes and ecosystems: the Alberta Oil Sands. Annals of the New York Academy of Sciences 1134:120-145.

peat. In addition, the restoration of ecosystems and re-sequestering of biological carbon could take many decades. The authors of the analysis identified two uncertainties requiring further research, including the proportion of biological carbon removed that is eventually emitted to the atmosphere and potential future trends in biological carbon emissions from mining and in-situ extraction. Further evaluation of the type of peatland ecologies disturbed (e.g. bogs versus fen), the variations in carbon/methane releases, the temporal patterns of the emissions, and the effectiveness of the reclamation projects would also help to improve assessments.

A second set of estimates is available using GHGenius 3.13, which uses both Suncor and Syncrude annual reports to make estimates of disturbed areas. The model calculates that loss of both soil and biological carbon together represent 0.08 gCO2e/MJ of fuel produced, or approximately 0.3% of the total source-to-tank GHG emissions. To better understand these differences between the two analyses, the GHGenius assumptions were compared to those from CBI/DUC analysis (2008). GHGenius considers a generic, default set of factors for the "oil production" category. An average soil carbon emission factor is also derived by weighing different disturbed lands with their respective emission factors within the model. The results are shown in Table 5 below.

Table 5: Estimates of Disturbed Area and Soil Carbon (GHGenius 3.13) – Generic Oil

Land	% of disturbed area	tonne C/hectare
CRP, pasture, grass	65%	70
Forest	10%	70
Desert	20%	10
Generic Agriculture	5%	70
Weighted Avg	100%	58

59	hectares disturbed/million cubic meter produced

GHGenius estimates that approximately 59 hectares are disturbed for each million cubic meters produced, which is fairly close to the 71 value derived by CBI/DUC.

The differences between the two estimates are clearer by comparing Tables 4 and 5. Part of the differences can be ascribed to the order of magnitude difference in the soil carbon emissions factor. The default generic oil category used by GHGenius is clearly not applicable for tar sands, but the emission factors and disturbed area can be adjusted by the user. The CBI/DUC estimates consider peat and mineral wetlands, which appear to have much larger soil carbon factors than those assumed in GHGenius for the generic oil category. The second difference – though relative minor by comparison -- is the estimated land area disturbed per unit of production as noted above. The third difference appears to be in terms of the accounting methodology: specifically amortizing and discounting of future CO_2 emissions. The methodology used by GHGenius is based on the methodology by Delucchi (1998) for energy-crop systems.[37]GHGenius assumes that the soil carbon takes 5 years decompose into atmospheric CO_2, such that approximately 1/5 of

[37] Mark Delucchi (1998), "Lifecycle Energy Use, Greenhouse Gas Emissions, and Air Pollution from the Use of Transportation Fuels and Electricity," Institute of Transportation Studies, University of California, Davis, December 1998 as cited by the documentation for GHGenius. "Documentation for Natural Resources Canada's GHGenius Model 3.0, September 15, 2005.

the loss is attributed to each barrel produced. It is unclear why the Delucchi approach for energy crops is appropriate for surface mining of tar sands. The Delucchi methodology uses amortization of emissions in cases where land is initially converted but crops can be grown continuously over a time period (e.g. a 30 year project life). Thus, to put the land use change factor on a per gallon basis (e.g. gCO2e lost/gallon), the initial loss of soil carbon would need to be distributed, or amortized, over the entire production volume expected for the project's lifetime. In contrast to biofuels, the land use change factor for tar sands is already on an incremental barrel basis (or volume fuel produced). Once an area is mined it is assumed that no further production from that area occurs so that amortization appears unnecessary.

In summary, the variations in methodology appear to explain the majority of differences between GHGenius and the CBI/DUC evaluation. Further evaluation of the methodologies is needed in addition to more detailed assessments of the land use impacts. The Canadian Boreal Initiative and Ducks Unlimited Canada also identified several additional areas for further research:

- Accurate estimates of the biological carbon emissions associated with oil sands mining, including the proportion of biological carbon removed from surface mines that is eventually emitted to the atmosphere.
- The potential future trends in biological carbon emissions from oil sands mining
- An evaluation of biological carbon emissions associated with in situ oil sands development. In situ development, although not requiring the removal of soil, has the potential to cause a larger cumulative footprint due to the greater extent of subsurface bitumen deposits.

Emissions Associated with Construction and Capital

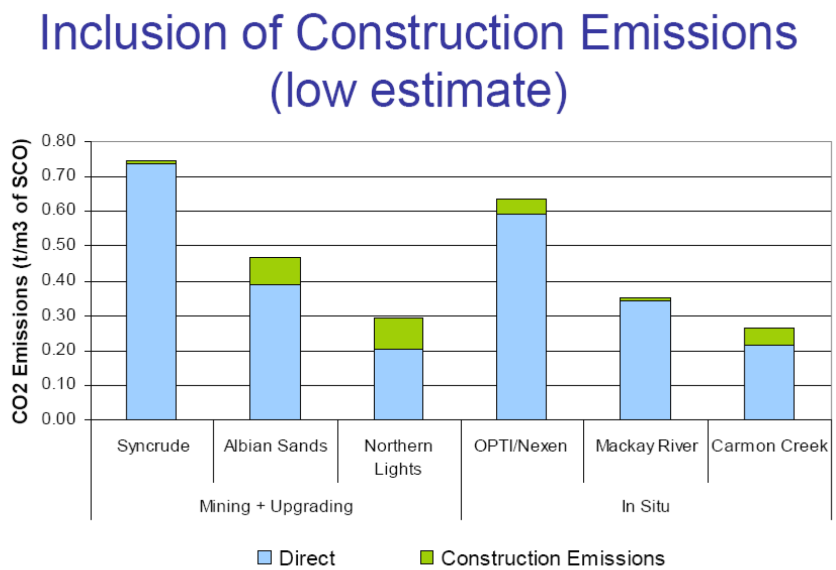
GHG emissions associated with the construction of operation facilities, machinery and vehicles, and roadways are not captured in current life cycle assessment models for tar sands. Direct and indirect emissions, including those caused by the production of the materials, roadways, and vehicles that make up the facility were reported by Bergerson and Keith (2006) and Bergerson (2007). Bergerson estimates that construction and capital-related emission can add an additional 20-25% to the direct production emissions, or an additional 9 – 11% of total life cycle emissions. Figure 3 displays lower and upper estimates, based on information collected from company surveys.[38] Note that none of the estimates cited above or in Table 2 include emissions associated with construction and capital.

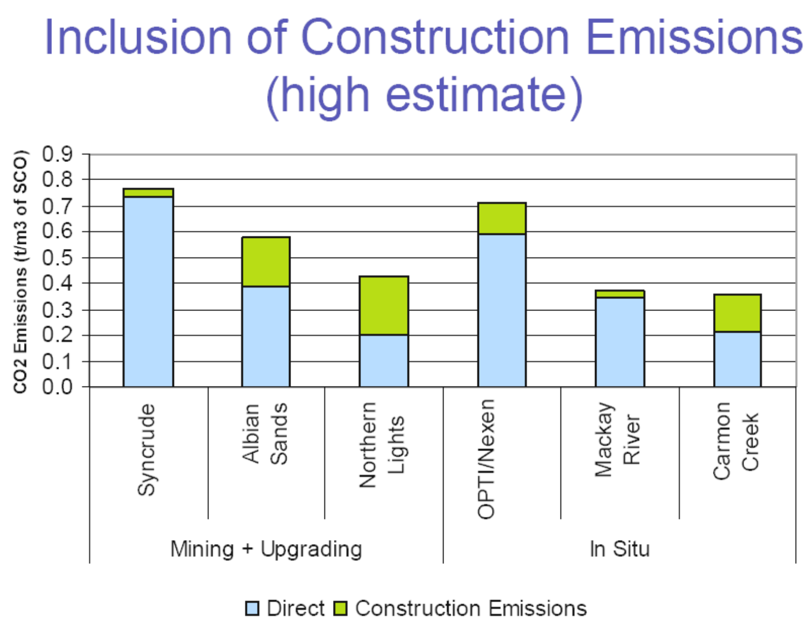
A life cycle assessment that expands the boundaries to include direct and indirect emissions associated with construction and capital would also require a similar approach be used for other fuels. Bergerson and Keith (2006) note that tar sands operations are more capital intensive than other fuel pathways and that these capital requirements have been climbing in recent years. The potential magnitude of these emissions suggests that construction and capital-related emissions should be accounted for in the life cycle analysis. Further details on the methodology used by

[38] J. Bergerson and D. Keith (2006). "Life Cycle Assessment of Oil Sands Technologies." Paper No. 11 of the Alberta Energy Futures Project. University of Calgary; J. Bergerson's (2007), "The Impact of LCFS on Oil Sands Development: Hybrid LCA Methods, Presentation at the InLCA/LCM Conference, October 2, 2007. Unversity of Calgary. http://www.lcacenter.org/InLCA2007/presentations/LCFS-Bergerson.pdf

Bergerson and Keith however are necessary to evaluate the inclusion of construction and capital-related emissions.

Figure 3: Estimates of Construction Emissions associated with Tar Sands. Source: from J. Bergerson's (2007) presentation, "The Impact of LCFS on Oil Sands Development: Hybrid LCA Methods, InLCA/LCM Conference, October 2, 2007. University of Calgary.





Mitigation Technologies: Carbon Dioxide Capture and Sequestration

Potential reductions of GHG emissions from the tar sands extraction and upgrading process are possible through fuel switching, greater efficiency, and the use of carbon dioxide capture and sequestration (CCS) .The latter has been proposed as a process to remove CO_2 generated during the production process and to permanently store the pollutants underground. One of the main point sources amenable to CCS is hydrogen plants producing feedstock used during the upgrading process for hydrocracking. Hydrogen can be generated through different processes, each of which yield different concentrations of CO_2 streams and have different associated costs of capture.[39] Upgraders as well as coke gasification are two additional points that emit streams of CO_2 which might be captured at varying costs depending on the purity and volume of the streams.

Use of CCS however would either require a significant enough price on CO_2 emissions for companies to install systems or federal/provincial requirements to do so -- neither of which currently exist. In addition, the capture of low-purity streams is not likely to occur unless the price on CO_2 emissions is high enough to pursue these streams. For large-scale adoption of CCS by the tar sands industry, it is likely that multiple regulatory, cost, and technical barriers would need to be overcome. For instance, the lack of a regulatory framework for CCS; uncertainty over long-term financial and legal responsibility for sequestration sites; the limited experience with long-term monitoring, measurement, and verification (MMV); additional costs for CCS; retrofitting of existing facilities and processes to capture CO_2; and the need to develop a significant pipeline network to transport CO_2 all remain significant hurdles. Large uncertainties remain. Given these barriers, many estimates suggest CCS will not be used to a large extent until the post 2020 timeframe.

Use of GREET to evaluate the use of CCS in hydrogen production facilities using natural gas as a feedstock results in the upgrading emissions falling from 8.7 g CO2e/MJ to 4.1 g CO2e/MJ. The default assumptions in GREET assume a 90% CO_2 capture rate from the central H_2 plant which appears to be aggressive. Similarly, the in-situ process modeled in GREET shows a reduction from 4.6 to 2.8 gCO2e/MJ. GHGenius results in different reduction amounts. For example, for synthetic crude oil derived from the mining-process, the well-to-pump (WTP) emissions decrease by 37% (roughly 13 gCO2e/MJ) -- significantly larger than GREET. GHGenius appears to assume that CCS is applied to both the feedstock recovery as well as fuel production stages. It is unclear which point sources associated with the recovery process that CCS would be applied. In addition, fuel distribution and storage as well as feedstock transmission also appear to decrease for an unexplained reason. The default assumptions in both GREET and GHGenius for CCS as applied to tar sands are unclear. Further evaluation of the opportunities for CCS and process modeling of the specific point sources where CCS would be applied appears to be needed.

[39] Matthew McCulloch, Marlo Raynolds, Rich Wong, (2006), *Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands, Pembina Insitute,* October.

Conclusion

Analysis of the available studies shows that a wide range of methodologies, data sources, assumptions, and cases have been evaluated. While emissions can vary widely between operations, there seems to be general consistency in the literature once various methodological differences are taken into account and once process-based pathways are established. As shown, both GREET and GHGenius allow for full life cycle assessments to be made.

Both the GREET and GHGenius model requires some familiarity by technical users in order to fully evaluate the internal assumptions. For the most part, the model documentation and the specific studies by Larsen and Wang (2005) and NRCan (2008) provide users with the major assumptions and inputs used (these are provided in the Appendix). Both models appear to be flexible enough to account for different assumptions made either at an industry level (or even a project specific level) with the caveat that technical familiarity is necessary.

In terms of the currently available data sources, there is room for improvement particularly in terms of data quality, uniformity, and transparency. In addition, none of the studies appear to incorporate the loss of soil/biological carbon or the emissions associated with the capital and construction. These factors appear to be significant and would directionally, further increase the overall GHG emissions due to tar sands.

Several general recommendations and observations are provided as follows:

- Improved Reporting. The requirements for mandatory reporting from facilities can help provide information for purposes of life cycle assessments.[40] However, since operations may have different levels of integration (e.g. extraction and upgrading occurring on one site), greater detail and reporting at a process-level or product-basis would allow data to be more readily incorporated into life cycle assessments. In addition, mandatory facility reporting does not necessarily require indirect emissions to be reported or for data to be also presented in terms of primary or secondary energy data.

- Greater Consistency and Transparency. Different reporting methodologies and assumptions make comparisons between different projects (or studies) difficult. More accurate and robust project-specific or industry-average values could be established if (1) there were greater consistency in reporting direct and indirect emissions and (2) greater transparency regarding the emission factors, life cycle boundaries, and calculations used. Expansion of the current life cycle boundaries is particularly relevant and may be needed if land use changes and construction/capital-related emissions are found to be significant sources.

- Inclusion of Additional Sources of GHG Emissions. Many of the project applications currently do not include indirect emissions related to the process fuels or other inputs. These should ideally be assessed or at minimum, included and noted. Specific factors for tar sands in terms of soil/biological carbon and construction/capital emissions should be

[40] Both the federal government and Alberta have GHG reporting requirements. See for instance http://environment.alberta.ca/2881.html and http://www.ec.gc.ca/pdb/ghg/onlinedata/downloadDb_e.cfm

developed and incorporated into life cycle assessments given the potential for these emissions to be significant. Including these factors would result directionally in higher emissions than shown here.

- Understanding Past, Current, versus Future Emissions. Much of the data provided by project applications are inherently based on a blend of both current emissions data as well as projected emissions data for future operations. Because of this variability in the analytical timeframe and scope of reporting, use of project data for developing industry averages remain challenging. However, the use of project data for confirmation of industry-average estimates is useful and has shown to be generally consistent based on comparison of the results.

Appendix A: *GREET Specific Results*

The Greenhouse Gases, Regulated Emissions and Energy use in Transportation model (GREET version 1.8b) is a fuel life cycle emissions model developed by the U.S. Department of Energy's Argonne National Laboratory. It has been widely utilized for two decades including by the U.S. Environmental Protection Agency and by the California Air Resources Board as a tool to assess life cycle emissions. Like most life cycle analysis models, the model itself depends on input assumptions provided by the user. GREET includes a large number of fuel pathways and incorporates two major ones for oil sands – extraction via surface mining and via in-situ recovery. The model also includes default assumptions based on studies by Argonne National Lab and based on external data from a variety of sources (e.g. published studies, industry information, and government agencies). The model has undergone periodic revisions and improvements as better data is made available.

GREET accounts for the indirect emissions associated with the energy inputs used the fuel cycle such as natural gas. In addition to natural gas, GREET allows for other options to be selected to produce steam and hydrogen, including nuclear electricity, coal gasification and petroleum coke.

The current GREET defaults assume that the energy efficiency of refining is the same for upgraded oil sands as for conventional oil. Refinery process modeling or actual refinery data could help reveal the robustness of this efficiency assumption. Consequently, the emissions and energy-use associated with the fuel production stage is independent of the crude feedstock used. Emissions associated with the fuel production stage for specific fuels or mixes (e.g. CaRFG, CARBOB) can thus be simply added to the emissions associated with the particular crude feedstock (e.g. tar sands, conventional crude).[41]

Table 6 and Table 7 below provide a breakdown of the energy use and GHG emission contributions for the different well to tank (or source to tank) stages assuming GREET 1.8b default values. The corresponding parameters from GREET are shown in Tables 6 and 7 respectively for surface mining and in-situ processes.

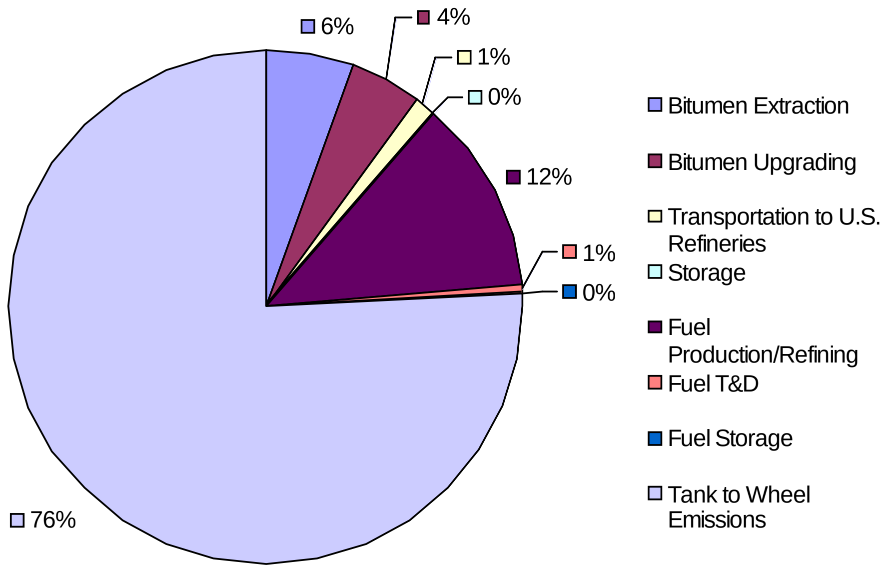
[41] The sole factor that needs be accounted for in this addition is the loss factor associated with processing the particular crude type to a fuel.

Table 6. Well to Tank Energy Analysis of Tar Sands: Surface Mining Process

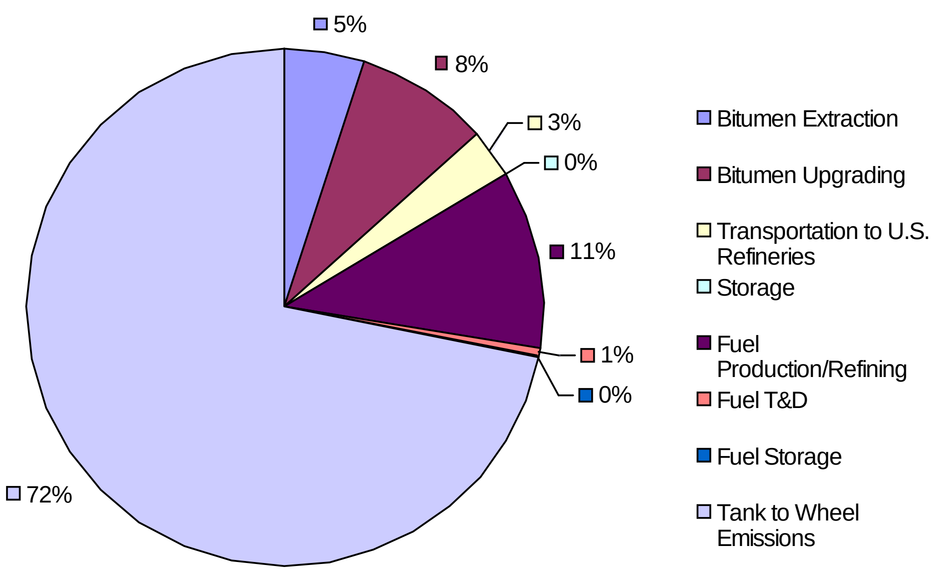
	Energy (Btu/mmBtu)	% Energy Contribution
Bitumen Extraction	73,750	5.6%
Bitumen Upgrading	58,192	4.4%
Transportation to U.S. Refineries	16,879	1.3%
Storage	0	0.0%
Fuel Production/Refining	164,477	12.5%
Fuel T&D	7,353	0.6%
Fuel Storage	0	0.0%
Total Well-to-Tank	320,651	24.3%
Tank to Wheel Emissions	1,000,000	75.7%
Total Well-to-Wheel	1,320,651	100.0%

Table 7. GHG Emission Summary for Tar Sands: Surface Mining Process

	GHG Emissions (gCO2e/MJ)	% Emission Contribution
Bitumen Extraction	5.1	4.9%
Bitumen Upgrading	8.7	8.3%
Transportation to U.S. Refineries	3.0	2.9%
Storage	0.0	0.0%
Fuel Production/Refining	11.5	11.0%
Fuel T&D	0.5	0.5%
Fuel Storage	0.0	0.0%
Total Well-to-Tank	30.8	29.5%
Tank to Wheel Emissions	73.6	70.5%
Total Well-to-Wheel	104.4	100.0%



Energy Use of Tar Sands: Surface Mining Process



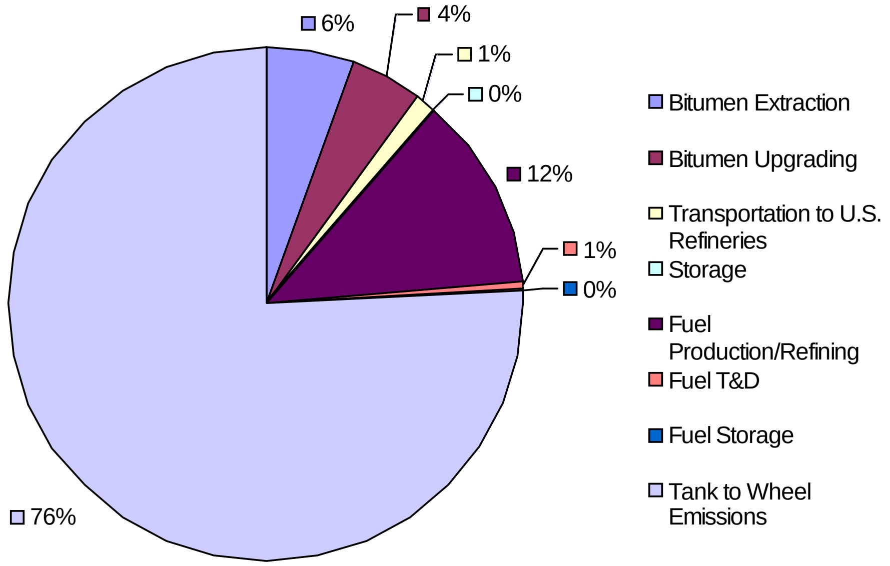
GHG Emission Contributions of Tar Sands: Surface Mining Process

Table 8. Well to Tank Energy Analysis of Tar Sands: In-Situ Process

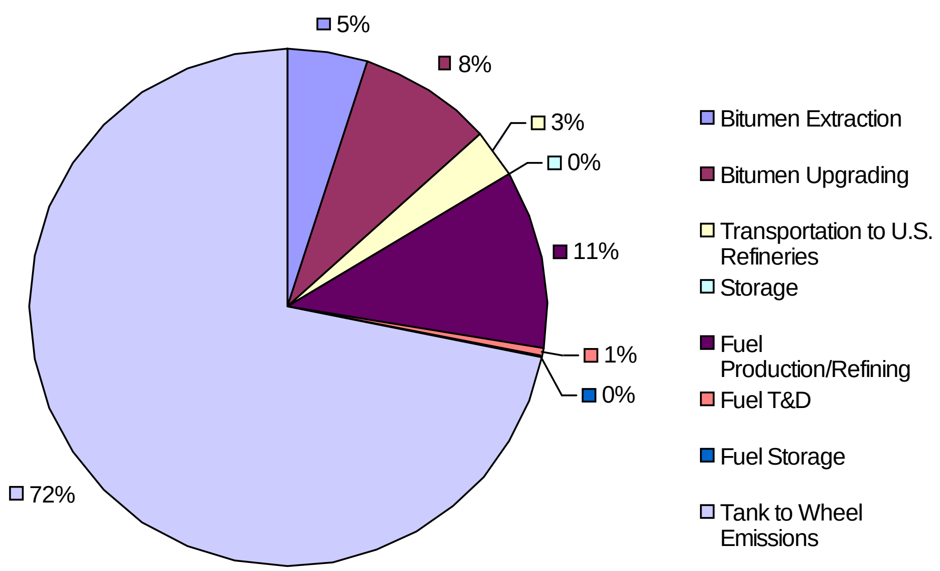
	Energy (Btu/mmBtu)	% Energy Contribution
Bitumen Extraction	208,411	14.5%
Bitumen Upgrading	32,177	2.2%
Transportation to U.S. Refineries	17,939	1.2%
Storage	0	0.0%
Fuel Production/Refining	172,766	12.0%
Fuel T&D	7,879	0.5%
Fuel Storage	0	0.0%
Total Well-to-Tank	439,173	30.5%
Tank to Wheel Emissions	1,000,000	69.5%
Total Well-to-Wheel	1,439,173	100.0%

Table 9. GHG Emission Summary for Tar Sands: In-Situ

	GHG Emissions (gCO2e/MJ)	% Emission Contribution
Bitumen Extraction	13.2	12.6%
Bitumen Upgrading	4.6	4.4%
Transportation to U.S. Refineries	3.0	2.9%
Storage	0.0	0.0%
Fuel Production/Refining	11.5	11.1%
Fuel T&D	0.5	0.5%
Fuel Storage	0.0	0.0%
Total Well-to-Tank	30.8	29.5%
Tank to Wheel Emissions	73.6	70.5%
Total Well-to-Wheel	104.4	100.0%



Energy Use of Tar Sands: In-Situ Process



GHG Emission Contributions of Tar Sands: In-Situ Process

Table 10: Tar Sands Recovery: Surface Mining

Parameters	**Units**	**Values**		**Notes**
Tar Sands Recovery: Surface Mining				
		Bitumen Extraction	Bitumen Upgrading	
Energy efficiency		94.8%	98.6%	GREET defaults for 2010
Shares of process fuels				
Diesel fuel		0.6%	0.0%	
Gasoline		0.0%	0.0%	
Natural gas		82.3%	97.1%	
Electricity		17.1%	2.8%	
Feed loss		0.0%	0.1%	
Hydrogen Used for Upgrading	Btu/mmBtu product		84,187	Added separately, assumes hydrogen is produced from natural gas
Equipment Shares				
NG large industrial boiler		100%		
	gCO2/mmBtu	59,379		
Diesel HDE truck		100%		
	gCO2/mmBtu	77,809		
Transportation				
Percentage of Fuel Transported by a Given Mode				
Pipeline		100%		
Pipeline Distance	miles	1900		
Pipeline Energy Intensity	Btu/miles-ton	253		

Table 11: Tar Sands Recovery: In-Situ Production

Parameters	**Units**	**Values**		**Notes**
Tar Sands Recovery: In-Situ Production				
		Bitumen Extraction	Bitumen Upgrading	
Energy efficiency		84.3%	98.6%	GREET defaults for 2010
Shares of process fuels				
Diesel fuel		0.0%	0.0%	
Gasoline		0.0%	0.0%	
Natural gas		97.2%	97.1%	
Electricity		2.8%	2.8%	
Feed loss		0.0%	0.1%	
Hydrogen Used for Upgrading	Btu/mmBtu product		32,364	Added separately, assumes hydrogen is produced from natural gas
Equipment Shares				
NG large industrial boiler		100%		
	gCO2/mmBtu	59,379		
Diesel HDE truck		100%		
	gCO2/mmBtu	77,809		
Transportation				
Percentage of Fuel Transported by a Given Mode				
Pipeline		100%		
Pipeline Distance	miles	1900		
Pipeline Energy Intensity	Btu/miles-ton	253		

Appendix B: GHGenius 3.13 Default Parameters

Process Fuels Used for Extraction of Bitumen (Worksheet S)

		SAGD	CSS	Mining
Fuel used	Proportion	0.60	0.15	0.25
Crude oil	l/m3	0.00	0.00	0.00
Diesel fuel	l/m3	0.00	0.00	15.00
Residual fuel	l/m3	0.00	0.00	0.00
Natural gas	m^3/m3	245.00	220.00	81.00
Coal	kg/m3	0.00	0.00	0.00
Electricity	kWh/m3	60.00	55.00	20.00
Gasoline	l/m3	0.00	0.00	0.25
Coke	kg/m3	0.00	0.00	0.00
Still Gas	m/m3	0.00	0.00	0.00
Leaks and Flares	L/tonne	1,742	1,742	3,000
	API	8.0	8.0	8.0
	Density	1.014	1.014	1.014
	Sulphur	4.5	4.5	4.5

Process Fuels Consumed and Co-Products Generated for Upgrading (Worksheet S)

		Standalone Upgrader Inputs	SCO from Bitumen + Standalone Upgrader	SCO from Integrated Operation
Crude oil	kJ/tonne		0	0
Diesel fuel	kJ/tonne		0	600,000
Residual fuel	kJ/tonne		0	9,548
Natural gas	kJ/tonne	2,000,000	15,311,573	2,600,000
Coal	kJ/tonne		0	0
Electricity	kJ/tonne	550,000	860,071	100,000
Gasoline	kJ/tonne		0	0
Coke	kJ/tonne	1,100,000	1,100,000	3,300,000
Still Gas	kJ/tonne	3,500,000	3,500,000	5,500,000
		7,150,000	20,771,644	12,109,548
			2,607	5,800
	Bitumen to synthetic mass ratio	1.25		
Co-products		bitumen	synthetic	
Coke	Gj/GJ	0	0.15	
Propane		0	0.015	

Appendix C: Conversion Factors and Parameters Used

Conversion Factors

Volume

1	m3 =	6.29	barrel
42	gal =	1.00	barrel

Energy

1	BTU =	1.055	kJ
129,670	BTU/gal crude oil (LHV) - Source: GREET 1.8b		

To estimate the g CO2e/MJ crude oil to g CO2e/MJ finished fuel it was assumed that the energy content of all refined products is equal to the energy content of the crude oil input. The heating values of most refining products deviate slightly from that of crude.[42] In reality, losses in crude oil will result in less than a 100% conversion of crude oil, so that the emission factors shown here (converted from a kg CO2e/barrel basis) may be slightly under-estimated. For instance, estimates by Wang (2007) for the weighted, average refinery efficiency [defined as energy in all petroleum products/(energy in crude input, other feedstock inputs, and process fuels)] was estimated to be 90.1% based on EIA data.[43] However, the inputs include not only crude oil feedstocks, but also process fuels (e.g. natural gas, petroleum coke, asphaltenes, still gas, electricity) in addition to other feedstock inputs (e.g. natural gas liquids, liquefied petroleum gases, unfinished oils, and blending components). A suitable conversion factor however is currently being reviewed in order to update the conversion factor used here.

[42] M. Wang, H. Lee, and J. Molburg (2004), "Allocation of Energy Use in Petroleum Refineries to Petroleum Products: Implications for Life-Cycle Energy Use and Emission Inventory of Petroleum Transportation Fuels," *International Journal of Life Cycle Assessment*, **9** (1), 34-44.
[43] M. Wang, "Estimation of Energy Efficiencies of U.S. Petroleum Refineries," Center for Transportation Research, Argonne National Laboratory, March 2008.