Setting the Record Straight: Lifecycle Emissions of Tar Sands

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Why Emissions from Our Fossil Fuel Based, Petroleum Sources Should Be Evaluated and Distinguished

Concern over the significant economic, environmental, and military toll of U.S. oil dependency has led to a number of policies to (1) improve efficiency of vehicles, (2) reduce consumption through smarter growth and providing greater mobility options, and (3) incentivize the development of alternative, low carbon fuels such as from advanced renewable biofuels, electricity, hydrogen, and natural gas.

In efforts to evaluate cleaner, alternative fuel sources, various efforts including the California Low Carbon Fuel Standard and the U.S. Renewable Fuel Standard have established efforts to score alternative fuels based on their greenhouse gas (GHG) emissions. Increasingly, research and analysis is also showing that petroleum fuel emissions can also vary significantly depending on the source of crude oil and production practices used. For example, the U.S. Department of Energy has found that, on a well-to-tank emissions basis, the variation between the lowest carbon-intensity crude oil source (U.S. domestic production) and highest carbon-intensity crude oil source (average Canadian tar sands) was 130% (or 2.3x).[1] On a well-to-wheels basis, this is equivalent to a 22% (or 1.2x) difference. Synthetic crude oils produced from unconventional sources such as coal and oil shale have even significantly higher well-to-wheels emission, equivalent to about a 130% increase (2.3x) and a 73% increase (1.7x) respectively.[2] Without accurate emissions accounting, fuel policies will ultimately fail to level the playing field between the cleanest alternative fuels and the dirtiest petroleum sources.

Setting the Record Straight: Lifecycle GHG Emissions of High Carbon Intensity Crude Oils

IHS CERA recently released a report “Oil Sands, Greenhouse Gases, and the U.S. Oil Supply” that reviews thirteen primary studies and estimates of GHG emissions from fuels produced from tar sands on a “well-to-wheels,” or lifecycle, basis.[3] The CERA report provides a range of 5 to 15% in increased emissions for tar sands versus the U.S. average crude oil baseline on a lifecycle (or well-to-wheels) basis. However, in reviews conducted by NRDC

[1] Well-to-tank analysis accounts for emissions associated with oil recovery and upgrading, transport, refining, and ultimately delivery to the tank or retail. Well-to-wheels, or full lifecycle, captures all of these emissions as well as combustion emissions (or vehicle tailpipe).

[2] Bartis, James T., Frank Camm, and David S. Ortiz (2008), “Producing Liquid Fuels from Coal: Prospects and Policy Issues,” RAND Corporation; Brandt, A.R.(2009) Converting oil shale to liquid fuels with the Alberta Taciuk Processor: Energy inputs and greenhouse gas emissions. Energy & Fuels. Issue 23, pp. 6253-6258. Results compared against the U.S. 2005 average baseline for gasoline as cited in the text.

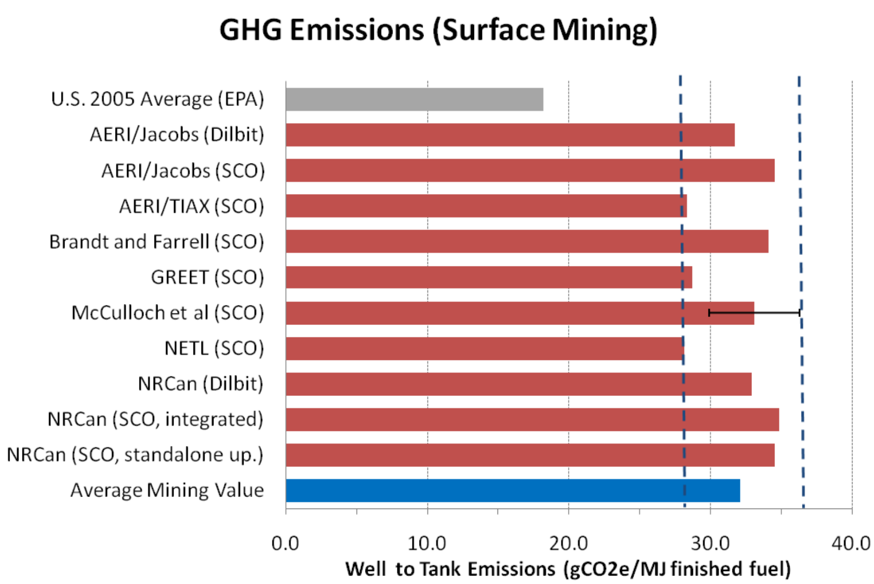
[3] http://www2.ihscera.com/docs/Oil_Sands_Energy_Dialogue_0810.pdf

in 2008 and 2010,[4] the results showed a much larger range of 8 to 37% higher emissions versus the U.S. average petroleum baseline.[5] Unfortunately, it is currently not possible to replicate or confirm CERA's results due to the lack of information provided. Any changes to the results of the primary sources are also difficult to evaluate based on the information in CERA's study.

The lack of transparency and inability to replicate the results is problematic in and of itself. But the CERA study also has serious omissions in their calculations that they do provide, in part because many of the primary source studies relied upon do not include important sources of emissions – such as fugitive and land use change emissions from mining. These additional sources should be noted and accounted for in a meta-analysis of the different lifecycle studies.

The two recent NRDC studies provided a review of the actual results from the literature and lifecycle models, without significant adjustment, in order to compare the emissions from producing tar sands via different methods (as shown below in Figure 1). Based on NRDC's review of the literature, the average value from the list of studies compiled was 14% greater emissions for tar sands produced from surface mining. For in-situ methods, the average found was 25% greater emissions for synthetic crude oil, 18% greater emissions for dilbit produced in-situ, and 17% greater emissions for synbit.

Figure 1: Comparison of studies. Well-to-tank emissions associated with surface mining production of tar sands. (grams CO_2e/MJ gasoline), LHV.



[4] Mui, S., D. Hannah and R. Hwang (2008), *Life Cycle Analysis of Greenhouse Gas Emissions from Tar Sands*, Natural Resources Defense Council, November 18, 2008; S. Mui, L. Tonachel, B. McEnaney, and E. Shope, *GHG Emission Factors for High Carbon Intensity Crude Oils.*
http://docs.nrdc.org/energy/ene_10070101.asp

[5] The U.S. average 2005 gasoline and diesel baseline was determined by the U.S. Environmental Protection Agency together with the U.S. Department of Energy. For reference, see EPA (2010), *Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis*. February 2010, EPA-420-R-10-006.

Mixing Tar Sands with Other Crude Oil Sources

CERA considers mixed barrels of bitumen and natural gas liquids (called condensates or diluent), effectively lowering the impact of the specific crude oil source (bitumen). This approach is also used in several other studies relied upon by CERA.[6] Instead of reporting the results separately in terms of gasoline produced from bitumen and gasoline derived from natural gas liquids, the approach mixes the crude oil and natural gas sources, effectively making bitumen emissions appear much lower. How much lower?

In Table 1 below we show the impact of diluting the bitumen results with results from natural gas liquids. Based on CERA's own estimates, the production of natural gas liquids (NGL) results in 70% lower "well-to-tank " emissions compared to bitumen. "Well-to-tank" emissions includes emissions from NGL recovery, transport, processing at the refinery, and delivery (but not combustion emissions from the final end-use). On a "well-to-wheels" basis, CERA estimated that NGL results in 21% lower "well-to-wheels" emissions, which includes end-use emissions, compared to bitumen from in-situ processes. Thus, the mixing of natural gas liquids into the results for bitumen lowers the apparent results by 6%, on a well-to-wheels basis.

Table 1: CERA estimates for bitumen produced by SAGD and for dilbit. The natural gas liquid estimates are shown based on extrapolation of the bitumen and dilbit estimates.

kg CO2e/bbl bitumen equivalent										
	Mixture	**Production**	**Upgrading**	**Transport**	**Refining**	**Dist.**	**Combustion**	**Well to Tank**	**Well to Wheels**	**% Decrease v. Bitumen**
Bitumen (SAGD)	70%	69.0	-	5.5	85.0	2.1	384.0	161.6	545.6	
Natural Gas Liquids (Diluent)	30%	5.7		5.5	35.0	2.1	384.0	48.3	432.3	21%
Mixed Barrel (Dilbit)		50.0	-	5.5	70.0	2.1	384.0	127.6	511.6	6%

Significant Emission Sources That Should Be Fully Included in Lifecycle Estimates

Important sources of emissions from land use change, venting and flaring, production of natural gas and electricity, and fugitive emissions from tailing ponds are not included in many of the studies that CERA relies upon. CERA's study admittedly draws the boundary tight around the plant, acknowledging it leaves out some emission sources, but does not report on how much these additional emission sources would add and whether it included certain emission sources. We provide additional information here.

Emissions Due to Steam Use: One of the largest determinants for emissions from in-situ recovery methods is the amount of steam used to recover a barrel of bitumen. The industry currently uses heat from generated steam to increase underground temperatures and allow for flow of the bitumen into the well. The amount of steam used is measured by a steam to oil ratio (SOR) which can vary as a function of reservoir geology and other physical characteristics.[7] The current range in industry varies between 2 to 7 SOR, with higher values meaning

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[6] TIAX (2009), *Comparison of North America and Imported Crude Oil Lifecycle GHG Emissions*, Final Report, TIAX LLC and MathPro Inc, prepared for Alberta Energy Research Institute., Jacobs (2009), *Life Cycle Assessment Comparison of North American and Imported Crudes*, Jacobs Consultancy and Life Cycle Associates, prepared for the Alberta Energy Research Institute.

[7] A. Charpentier, J. Bergerson, and H. MacLean, "Understanding the Canadian oil sands industry's greenhouse gas emissions," *Environ. Res. Lett.* **4**, (2009).

more steam energy required (and emissions) to produce a barrel of bitumen. CERA cites the use of a SOR of 3. Several of the studies referenced by CERA also consider cases where the SOR is either 2.5 or 3.[8] However, the current industry average steam usage is about 20% higher than the value used by CERA, as shown in Table 2.

Table 2 shows the SOR calculated for in-situ projects in commercial operation in Alberta, based on the data collected by the Energy Resources Conservation Board.[9] A weighted, industry average SOR is estimated based on the ERCB data and size of the projects and results in a value of 3.6 SOR rather than a value of 3.0.[10] What does this translate to in terms of additional greenhouse gas emissions?

Based on a sensitivity analysis documented in a Jacobs Consultancy report, an increase in SOR from 3 to 5 resulted in an increase of approximately 7.3 g CO_2e/MJ of crude oil.[11] Each unit increase in SOR results in an increase of about 4.9 g $CO2_e$/MJ when translated on a gasoline-basis. Thus, adjusting CERA results from 3 to 3.6 SOR would result in an additional 2.9 g CO_2e/MJ for gasoline, or another 3% increase in WTW emissions versus the average U.S. baseline.

Table 2: Steam to Oil Ratios for the various projects for year 2009. Source: ERCB (2010).

Operator	Project	Recovery Method	Annual Bitumen Production (10^6 x m^3)	SOR (weighted average)
Imperial Oil Resources	Cold Lake	Commercial-CSS	8.20	3.49
EnCana Corporation	Foster Creek	Commercial-SAGD	4.40	2.49
Canadian Natural Resources Limited	Primrose and Wolf Lake	Commercial-CSS	3.58	6.00
Suncor Energy Inc.	Firebag	Commercial-SAGD	2.83	3.13
Suncor Energy Inc.	Mackay River	Commercial-SAGD	1.70	2.52
Devon Canada Corporation	Jackfish 1	Commercial-SAGD	1.30	2.42
ConocoPhillips Canada Resources Corp.	Surmont	Commercial-SAGD	0.85	2.81
Cenovus FCCL Ltd.	Christina Lake	Commercial-SAGD	0.77	2.11
Nexen Inc.	Long Lake	Commercial-SAGD	0.72	5.34
Japan Canada Oil Sands Limited	Hangingstone	Commercial-SAGD	0.43	4.04
Great Divide Oil Corporation	Great Divide	Commercial-SAGD	0.37	3.71
Shell Canada Limited	Peace River	Commercial-CSS	0.36	4.25
Husky Oil Operations Limited	Tucker Lake	Commercial-SAGD	0.22	7.26
Shell Canada Energy	Orion	Commercial-SAGD	0.16	6.43
Meg Energy Corp.	Christina Lake	Commercial-SAGD	0.05	6.54
ConocoPhillips Canada Limited	Surmont Pilot	Commercial-SAGD	0.03	3.41
Total E&P Joslyn Ltd.	Joslyn Creek	Commercial-SAGD	0.03	1.94
Total Industry			**26.01**	**3.58**

Direct Land Use Change Emissions: Emissions from the removal of vegetation and trees, soil, and peatland are significant particularly for mining practices and should be included. In a study involving five major Canadian and U.S. universities, Yeh et al (2010) estimated that surface mining of tar sands resulted in between a 0.9 to

[8] TIAX (2009) and Jacobs (2009).
[9] Energy Resources Conservation Board (2010), *ST-53 2009 Alberta In-Situ Oil Sands.*
[10] Note that a large number of the smaller sized projects are in early stages of commercial operation and tend to have higher SOR. Taking only the top 6 projects (in terms of production size) results in a SOR of 3.5.
[11] Jacobs (2009), Table 8-5.

2.5% increase in the well-to-wheel emissions (or 0.8 – 2.3 g CO_2/MJ) versus the baseline (2005 average U.S. gasoline). The range was highly dependent on the type of lands displaced and mitigation practices used, with the removal of peatland having the largest impact. A representative value was determined to be 1.3 g/MJ or about a 1.4% increase in well-to-wheel emissions. CERA recognizes that direct land use emissions could increase their estimate for surface mining by as much as 6% on a well-to-wheels basis versus the baseline but did not include these emissions in their calculations (p. 19).

Fugitive emissions: Fugitive emissions can come from sources such as leaks as well as from practices such as the creation of tailing ponds which release methane (CH_4). Yeh et al (2010) estimated that fugitive emissions from tailing ponds (mining) could add 0 to 9% emissions compared to the baseline, on a well-to-wheels basis (or 0 to 7.91 g CO_2/MJ). The representative value reported by Yeh et al (2010) of 2.6 g CO_2/MJ, or a 2.8% WTW increase, is larger than the industry average estimates reported to Environment Canada's National Inventory Report of 0.9 g/MJ for mining. The CERA report does not appear to add fugitive emissions into its estimates although this is difficult to verify. Some of the sources CERA relies upon include an emissions factor while others do not.

Venting and Flaring Emissions: Venting and flaring emissions are not included in a number of the source studies relied upon by CERA, such as CAPP (2008), RAND (2008), and the U.S. Department of Energy's GREET lifecycle model.[12] It is unclear whether CERA applied a factor for these emissions. Nevertheless, TIAX (2009) estimated that the range of between 0.5 g/MJ (for mining) to 3.3 g/MJ (for in-situ) would result in a 0.5 to 3.6% increase in well-to-wheel emissions versus the baseline.

Emissions from Production of Natural Gas and Electricity: CERA states that indirect emissions are not included in its evaluation. Significant amounts of emissions can be associated with imports of natural gas, electricity, and other products. The Jacobs (2009) study estimated that the inclusion of these emissions would add about 4 to 5.3 g/MJ, or about 4.3 to 5.7% increase in emissions, versus the baseline.

Crediting for Electricity Co-Generation and Export to the Grid: While many facilities purchase electricity off the grid, a number of facilities cogenerate enough electricity to export back to the grid. The CERA study considers two estimates to "credit" for the co-generated electricity, thus reducing the effective emissions from bitumen production. The first high-end estimate assumes natural gas co-generated electricity displaces coal-fired generation. For the low-end estimate, the CERA study provides a GHG emission credit equivalent to an "Alberta offset" credit, equivalent to a generation mix with about two-thirds the emissions of a coal-fired plant. These assumptions results in an 8 to 14% reduction in production emissions for bitumen, or 1-2% over the entire well-to-wheels basis.

However, CERA does not use an actual electricity dispatch model to estimate what generation sources might actually be displaced by tar sands facilities exporting electricity. The crediting is problematic in that it fails to consider the scenario whereby natural gas co-generation simply displaced other natural gas facilities. If this were the case, the credit would be near zero. Second, as the electricity sector becomes subject to greenhouse gas emission standards and other requirements over time, the CERA approach could end up crediting for emission

[12] CAPP (2008), Environmental Challenges and Progress in Canada's Oil Sands, Canadian Association of Petroleum Producers; RAND Corporation (2008), Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs.

reductions that would likely have occurred anyhow. Thus, these electricity sector emission reductions would not be real or additional to what would have occurred anyhow.

Table 3 better demonstrates what type of capacity was added over the past 12 years in Alberta. Essentially, these can be considered the marginal sources that were added. Most of the added new generation has not been coal fired electricity. Natural gas cogeneration is the largest new installed capacity (mainly from new tar sand production facilities) at 55%, followed by natural gas generation at 19%, then renewables/biomass-fired generation at 15%, and last, coal-fired generation at 11%.

Table 3: Newly Installed Generation in Alberta, Canada since 1998.

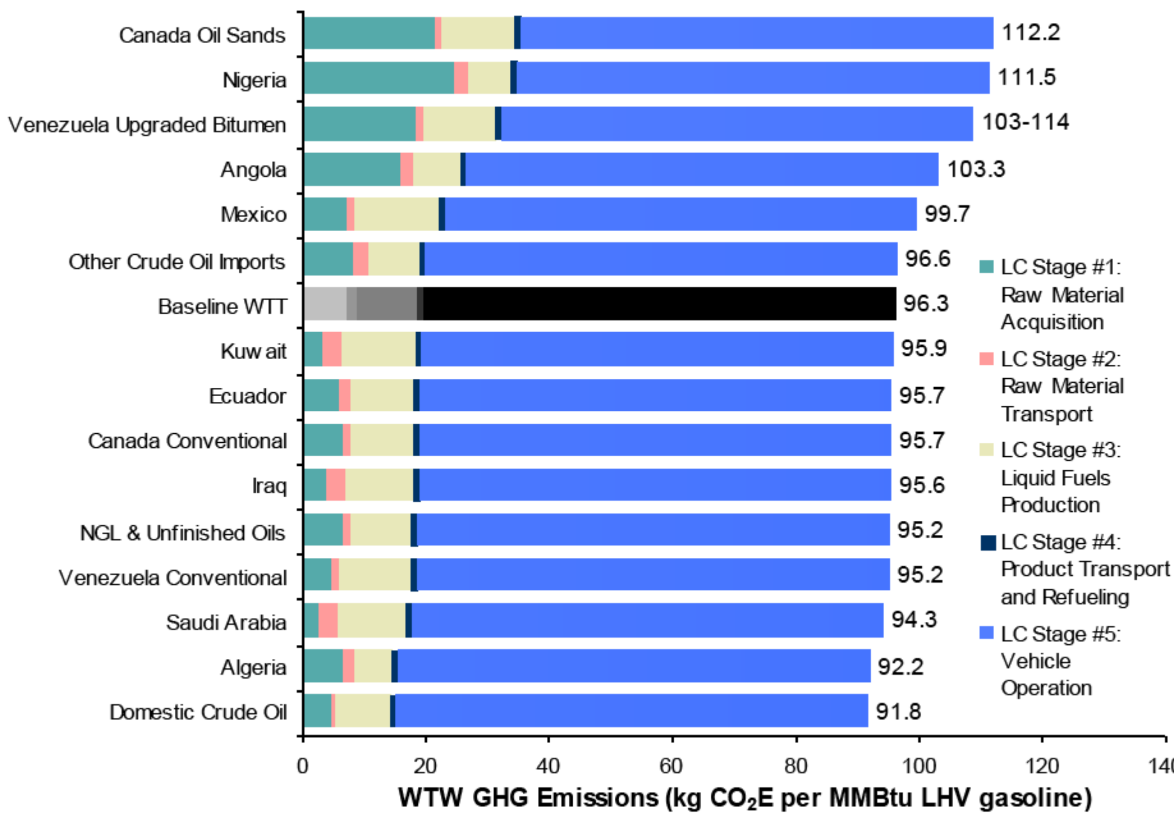
Plant Type	New Installed Capacity (MW)	% of Total
Renewables/Biogas	873	15%
Natural Gas	1082	19%
Gas Cogeneration	3103	55%
Coal	607	11%
Total	5665	100%

Source: http://www.energy.alberta.ca/Electricity/682.asp#import

The CERA Report Does Not Appear to Reflect the Range of Other Studies

An extensive analysis conducted by the U.S. Department of Energy is shown below, showing Canadian tar sands with significantly higher emissions compared to the U.S. average baseline. The average for Canadian crude oils was estimated to be 17% higher on a well-to-wheels basis compared to the U.S average (10% higher for surface mining and 21% higher for in-situ). CERA incorporates this study, but its range does not reflect the results from U.S. DOE. In addition, CERA cites using GHGenius, a lifecycle model commissioned by Environment Canada, yet arrives at far lower values than the 18% higher emissions estimated by GHGenius for surface mining, 22-26% higher emissions for synthetic crude oil produced via Cyclic Steam Stimulation (CSS), and 24% higher emissions for dilbit produced via steam assisted gravity drainage (SAGD). The ranges provided for the Jacobs (2009) and TIAX (2009) studies also do not appear to be fully reflected.

Figure A-3. Contribution of Feedstock Source to the 2005 Baseline WTW GHG Emissions for Gasoline



Source: NETL (2009), *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions*, March 27, 2009, U.S. Department of Energy, DOE/NETL-2009/1362.