GHG Emission Factors for High Carbon Intensity Crude Oils

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Summary

A growing body of technical work assessing the greenhouse gas (GHG) emissions associated with the production of high carbon intensity crude oils (HCICOs) is now available. This report compares the different estimates from both the technical and scientific literature in this area. As discussed by a previous review paper by Mui et. al. (2008) and by Charpentier et al. (2009), there are differences in numerous studies available largely due the use of different data sources, methods, lifecycle boundaries, and assumptions used. Comparisons between reports is challenging because of the different basis used (e.g. CO_2 per barrel SCO/bitumen/conventional, CO_2 per MJ finished fuel product) and lifecycle stages assessed (e.g. extraction and upgrading, well to pump, well to wheels). This document compiles general results from the body of literature for comparison purposes.

High carbon intensity crude oils (HCICOs) include those produced using production methods that are energy intensive or involve practices that result in higher emissions. Typically, HCICOs can include unconventional sources (e.g. tar sands, coal, oil shale), heavy oils, as well as conventional sources that require additional energy for crude oil recovery or use practices that result in larger emissions (e.g. Nigerian crudes with flaring, Middle East and California thermal enhanced oil recovery).

GHG life cycle emission factors for three types of unconventional sources are presented: tar sands (called oil sands by industry), coal-to-liquids, and oil shale. Other sources, such as NETL (2008), AERI/TIAX (2009), and AERI/Jacobs (2009) have examined emissions of other sources such as Nigerian crudes with flaring and Venezuelan heavy crude oils. A comparison of emissions factors from different studies are provided below (Summary Table) as well as recommendations to which source(s) would be adequate to establish a default emissions factor.

Throughout the document, lifecycle or "well-to-wheel" (WTW) emissions refer to those associated with oil recovery, upgrading, transport, refining, distribution, and combustion emissions. "Well-to-tank" (WTT) refers to emissions upstream of the vehicle tank, absent the actual combustion emissions. "Tank-to-wheel" (TTW) refers only the combustion emissions.

Summary Table: Emission factors for high carbon intensity fuels. Detail on sources provided below.

Fuels	Well-to-wheel Emissions (gCO2e/MJ)	GHG % Increase vs. US 2005 Average	Range
Tar Sands (source: literature avg)			
Surface Mining	106	14%	8% to 19%
Synthetic Crude Oil	116	25%	16% to 37%
Dilbit	110	18%	9% to 24%
Synbit	108	17%	13% to 21%
Coal to Liquids (source: RAND)			
CTL	210	128%	
CTL with 85% CCS	94	2%	-12% to 16%
Oil Shale (source: Brandt)			
In situ processing	137	49%	23% to 49%
Ex situ processing	159	73%	47% to 73%

Estimates from currently available literature show that, on a wells-to-wheel basis, greenhouse gas (GHG) emissions for tar sands produced using surface mining results in 8 to 19% greater emissions (101 to 111 g CO_2/MJ) versus the U.S. 2005 average gasoline baseline as estimated by U.S. Environmental Protection Agency (93 g CO_2/MJ).[1] GHG emissions for tar sands produced using in-situ methods results in 16 to 37% greater emissions for synthetic crude oil (108 to 128 g/MJ), 9 to 24% greater for "dilbit" (101 to 116 g/MJ), and 13% to 21% greater for "synbit" (105 to 112 g/MJ).[2] Note that these estimates do not include emissions from land use change. The average value from the list of studies compiled here is 14% greater emissions for tar sands produced from surface mining. For in-situ methods, the average is 25% greater emissions for synthetic crude oil produced, 18% greater emissions for dilbit produced in-situ, and 17% greater emissions for synbit.

Well-to-wheel GHG emission estimates for coal to liquids (CTL) production are based on conceptual plant designs as opposed to on-the-ground operations. Estimates for CTL vary widely depending on the process configuration and plant efficiencies assumed. Based on three sources, CTL emissions could be 110% to 180% greater (or 2.1x to 2.8x) versus the U.S. 2005 average diesel baseline (92 gCO_2/MJ).

Well-to-wheel GHG estimates for oil shale are based on demonstration and test project data. Brandt (2007 - 2010) provides the most extensive analysis of oil shale with a range of estimates resulting in 23% to 73% (1.2 to 1.7x) greater emissions versus the U.S. 2005 average diesel baseline.

Tar Sands

Tar sands are currently developed almost exclusively in Alberta, Canada, with current production at approximately 1.2 million barrels per day with one of the largest bitumen reserves in the world. Other reserves exist globally in countries such as Madagascar, the Republic of Congo, and the Russian Federation.[3] Some of these resources are currently being considered for development.

The results from publically available studies and lifecycle models are shown. Note that a number of additional studies and primary data from facilities are available and cited in some of the review papers, but are not compiled below. A review of the methodologies and evaluation of differences in lifecycle boundary conditions is beyond the scope of this document.[4]

- Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. Default results from Versions 1.8b. U.S. Department of Energy's Argonne National Lab.
- NRCan/S&T (2008), *2008 GHGenius Update*, prepared for Natural Resources Canada by (S&T)[2] Consultants. August 15, 2008. [consultant report on model results]

[1] Note that the U.S. 2005 baseline includes emissions from higher carbon-intensity crude oils produced domestically and imported. The baseline would be lower if these crude oil sources were removed.

[2] Dilbit refers to a mixture of diluents and bitumen. Synbit refers to a mixture of synthetic crude oil and bitumen.

[3] Lorne Stockman (May 2010), *Tar Sands in Your Tank: Exposing Europe's Role in Canada's Dirty Trade*, Greenpeace and The Borealis Centre.

[4] GREET and GHGenius results were produced using the default assumptions and values. WTT results for AERI/TIAX (2009) are for U.S. PADD 3 and show the average and ranges of the low and high estimates. Results from NETL (2008, 2009) are broken down into surface mining and in-situ syncrude pathways and using the oil sands average for transport, refining, and distribution/refueling emissions. For the AERI/JACOBS (2009) study, high and low ranges for dilbit produced via in-situ production represent differences in whether naphtha is recycled or converted to fuel.

- Charpenier, A.D., J.A. Bergerson, and H.L. MacLean, (2009),"Understanding the Canadian oil sands industry's greenhouse gas emissions," *Environmental Research Letters*, 4, 2009. p. 1 – 11. [review paper]
- McKellar, J, A.D. Charpentier, J.A. Bergerson, H.L. MacLean (2009), "A life cycle greenhouse gas emissions perspective on liquid fuels from unconventional Canadian and US fossil sources," *International Journal on Global Warming*, 1, Nos 1/2/3, p 160-178. [review paper]
- 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. [review paper]
- 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. [review paper]
- AERI/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.
- AERI/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.
- NETL (2008), *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 28, 2008, U.S. Department of Energy, DOE/NETL-2009/1346.
- 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.
- McCulloch, M., M. Raynolds, and R. Wong (2006), *Carbon Neutral 2020 – A Leadership Opportunity in Canada's Oil Sands*, Pembina Institute, Calgary, Alberta, October 2006.
- EPA (2010),*Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis*. February 2010, EPA-420-R-10-006. [provides analysis of average U.S. petroleum baseline for 2005]

The results are summarized below in the Figures and Tables. For comparison purposes, the U.S. 2005 average baseline for gasoline is provided, based on the U.S. Environmental Protection Agency's Renewable Fuel Standard 2 documentation (EPA 2010) and NETL (2008).

Surface Mining:

NETL (2008) results are based on Syncrude's project and their estimated 2005 production rates, as reported by the operator. The AERI/TIAX (2009) results are based on CNRL Horizon 2003 project application data. The project was still in start-up as of 2007. Stakeholder review of the AERI/TIAX (2009) point out that reliance on this recent project resulted in lower emissions than using operator data from the three main operating mining projects (Suncor, Syncrude and Albian Sands).[5] Potential differences in estimates between the NETL and AERI/TIAX study are unclear.

GREET default values typically fall on the lower end for both mining and in-situ values. The values are based largely on the 2004 Alberta Chamber of Resource's report, "Oil Sands Technology Roadmap: Unlocking the Potential," and uses industry aggregate information versus project submission data. It is

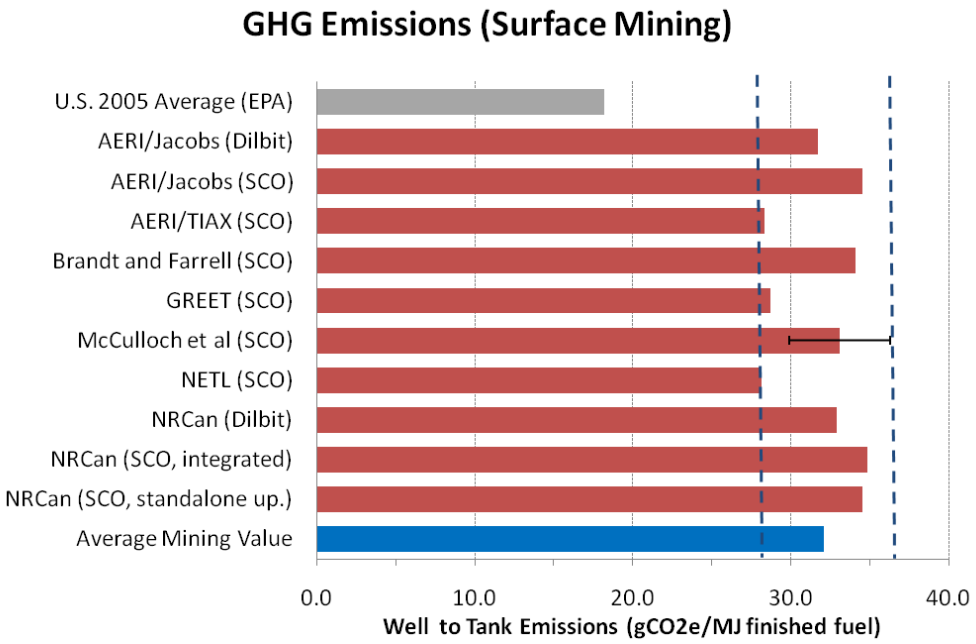
[5] "Life cycle analysis of North American and Imported Crude Oils," Post-Workshop Stakeholder Input. Academic reviewers also raised significant concerns regarding the large differences in the results between the studies, use of atypical project data, and lack of sufficient documentation. http://www.albertainnovates.ca/energy/major-initiatives/lca/lca-comments

difficult to verify the information in GREET due to use of secondary sources of data. One reviewer for this document cited that the GREET results are lower than those from the actual Alberta report largely because natural gas and electricity were included but coke combustion appears to have been left out as a primary energy source. The diesel consumption for mining operations in GREET also appeared significantly lower than those for other tar sands LCAs. The GREET values are still included in this review but it is noted that the value will tend to lower the average and overall range for mining emissions.

NRCan values allow for greater transparency versus other studies, since the sources are documented, based on project-submission data, and can be reproduced through a government-sponsored, publically available model (GHGenius). The results are close to the average and would be reasonable to use as a "representative" default value for surface mining emissions. It is recommended therefore that NRCan values are used.

Estimates from currently available literature show that, on a wells-to-wheel basis, greenhouse gas (GHG) emissions for tar sands produced using surface mining results in 8 to 19% greater emissions (101 to 111 g CO_2/MJ) versus the U.S. 2005 average gasoline baseline (93 g CO_2/MJ).[6] The average value from the studies was 106 g CO_2/MJ or about 14% greater emissions.

Figure 1: Comparison of studies. Well-to-tank emissions associated with surface mining production of tar sands. (grams CO_2e/MJ gasoline), LHV. For the key to the acroynms, see the footnote.[7]



[6] EPA (2010). Note that the U.S. 2005 baseline includes emissions from higher carbon-intensity crude oils produced domestically and imported. The baseline would be lower if these crude oil sources were removed.

[7] SCO refers to synthetic crude oil, "up" refers to upgrading, "integrated" refers to an integrated mining and upgrading operation. The results from TIAX's study for PADD 2 are presented.

Table 1: GHG emission factors for tar sands (surface mining) based on various studies. All units in gCO_2e/MJ gasoline, LHV. Tank to Wheel (TTW) values differ from different studies. In some cases, EPA default values for TTW were used.

Study	Crude Type	Production Method	WTT	TTW	WTW	Low	Hi
U.S. 2005 Average (EPA)	US (2005)	Baseline	18	75	93		
AERI/Jacobs (Dilbit)	Dilbit	Mining Only	32	74	105		
AERI/Jacobs (SCO)	SCO	Mining + Upgrading (Coker)	35	74	108		
AERI/TIAX (SCO)	SCO	Mining + Upgrading	28	74	102		
Brandt and Farrell (SCO)	SCO	Mining+ Upgrading	34	75	109		
GREET (SCO)	SCO	Mining + Upgrading	29	75	103		
McCulloch et al (SCO)	SCO	Mining + Upgrading	33	75	108	105	111
NETL (SCO)	SCO	Mining + Upgrading	28	73	101		
NRCan (Dilbit)	Dilbit	Mining Only	33	75	108		
NRCan (SCO, integrated)	SCO	Mining + Upgrading (integrated)	35	75	110		
NRCan (SCO, standalone up.)	SCO	Mining + Upgrading (standalone)	35	75	109		
Average Mining Value			**32**	**74**	**106**	101	111

In Situ Production:

For in-situ production pathways, results for synthetic crude oil (SCO), dilbit (diluent and bitumen), synbit (SCO and bitumen) are presented below in Figure 2(a-c). In all cases, the bitumen are produced either via steam assisted gravity drainage (SAGD) or cyclic-steam stimulation (CSS).

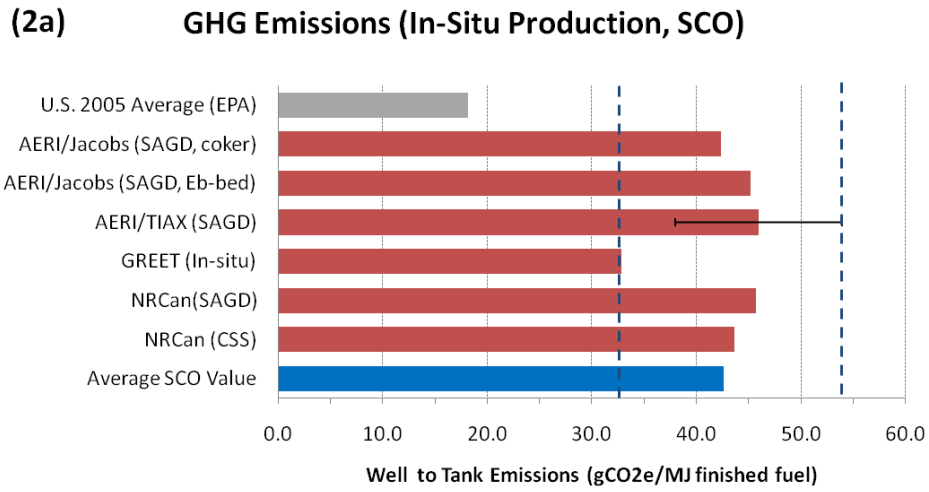
The SCO produced via in-situ methods appears to be generally higher, on average, than SCO produced via surface mining. The dilbit cases generally appear to have lower emissions than the SCO only pathways. This appears to be an artifact of the TIAX and Jacobs studies considering a "mixed" barrel of tar sands product with diluent, a light natural gas condensate or pentanes plus (C5+) that is blended to facilitate the transport of bitumen. Because the diluent generally has high energy content but less processing emissions associated with its use, a barrel of bitumen mixed with diluent will generally appear to have lower emissions on an energy or barrel basis. The bitumen and diluent streams, when used in a refinery, also result in different products. It is therefore recommended that agencies consider the emissions from the bitumen and diluent streams separately as opposed to combining emissions from these two different inputs.[8]

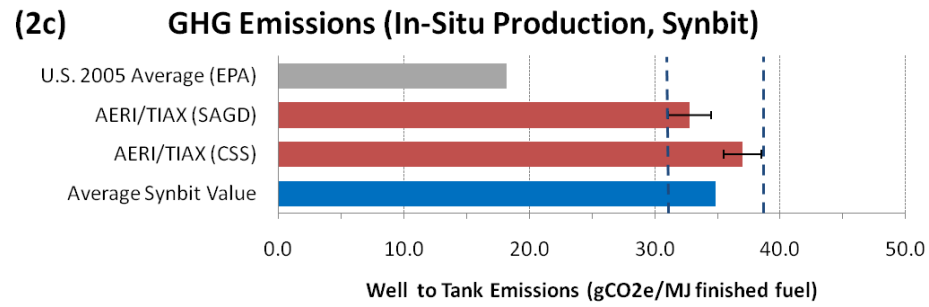
Based on the above information and review, it appears that the NRCan values are again reasonable to use as a "representative" value for in-situ production emissions.

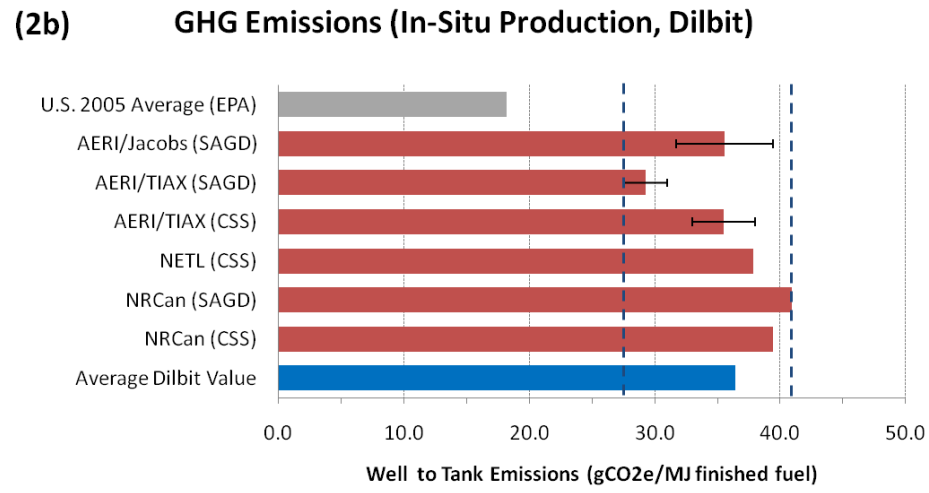
GHG emissions for tar sands produced using in-situ methods results in 16 to 37% greater emissions for synthetic crude oil (108 to 128 g CO_2/MJ). The dilbit cases results in 9 to 24% greater emissions (101 to 116 g/MJ), and the two synbit cases from the one TIAX study result in 13% to 21% greater emissions (105 to 112 g/MJ). The average value for SCO results in 25% greater emissions (116 g/MJ), for dilbit 18% greater emissions (110 g/MJ), and for synbit 17% greater emissions (108 g/MJ).

[8] Currently, Canadian supplies of diluent are tight with additional supply being imported to blend with tar sands.

Figure 2: Comparison of studies. Well-to-tank emissions associated with in-situ production of tar sands resulting in (a) SCO, (b) dilbit, and (c) synbit. Units in grams CO_2e/MJ gasoline, LHV. For the key to the acronyms, see the footnote.[9]







[9] Coker refers to the use of a delayed coker unit for upgrading. Eb-bed refers to an ebulating bed hydrocracking unit which uses a significant amount of hydrogen. The results from the TIAX study for PADD 2 are presented.

Table 2: GHG emission factors for tar sands (in situ production) based on various studies. All units in gCO_2e/MJ gasoline, LHV. Tank to Wheel (TTW) values differ from different studies. In some cases, EPA default values for TTW were used.

Study	Crude Type	Production Method	WTT	TTW	WTW	Low	Hi
U.S. 2005 Average (EPA)		Baseline	18	75	93		
AERI/Jacobs (SAGD, coker)	SCO	SAGD + upgrading via coker	42	74	116		
AERI/Jacobs (SAGD, Eb-bed)	SCO	SAGD + upgrading via Eb-bed	45	74	119		
AERI/TIAX (SAGD)	SCO	SAGD + Upgrading	46	74	120	112	128
GREET (In-situ)	SCO	In-Situ + upgrading (standalone)	33	75	108		
NRCan(SAGD)	SCO	SAGD + upgrading (standalone)	46	74	119		
NRCan (CSS)	SCO	CSS + upgrading (standalone)	44	74	117		
Average SCO Value			**43**	**74**	**116**	**108**	**128**
AERI/Jacobs (SAGD)	Dilbit	SAGD dilbit	36	74	109	105	113
AERI/TIAX (SAGD)	Dilbit	SAGD	29	74	103	101	105
AERI/TIAX (CSS)	Dilbit	CSS	36	74	109	107	112
NETL (CSS)	Dilbit	CSS	38	73	110		
NRCan (SAGD)	Dilbit	SAGD	41	75	116		
NRCan (CSS)	Dilbit	CSS	39	74	113		
Average Dilbit Value			**36**	**74**	**110**	**101**	**116**
AERI/TIAX (SAGD)	Synbit	SAGD	33	74	106	105	108
AERI/TIAX (CSS)	Synbit	CSS	37	74	111	109	112
Average Synbit Value			**35**	**74**	**108**	**105**	**112**

Coal to Liquids

Results from three sources for coal to liquid are shown.

There are a number of major plant designs currently being proposed. Since no plants are currently in operation in the U.S., assumptions of the fuel cycle process are necessarily based on conceptual plant designs such as those being proposed by CTL plant developers, academic researchers, and U.S. Department of Energy studies. Two plant designs in particular, a once-through system and a recycle system, impact the amounts of CO_2 that can be captured, the products produced, and the overall plant efficiency. The once-through system allows for a single pass of the syngas through the Fischer-Tropsch (FT) unit, allowing for more tailgas to be combusted for electricity generation. By contrast, the recycle system recirculates the tailgas from the FT unit to allow for higher fuel conversion rates. The recycle system potentially allows for additional removal of CO_2 from the stream by using an amine unit for instance. Less tailgas is generally available for electricity co-production however. Depending on the catalyst used for conversion of syngas to the fuel, a range of hydrocarbons can be produced including FT diesel, FT naphtha, down to waxes. In addition to catalyst variation, reactor temperature and residence times affect the products produced. Other plant designs assume that synthetic crude oil would be produced with subsequent upgrading to finished products occurring at conventional refineries (as opposed to upgrading at the plant).

The largest variables affecting the overall fuel production emissions are as follows, in general decreasing order of importance:

- overall plant efficiency,
- rates of CO_2 capture and disposal,
- production of other products including but not limited to electricity,
- rates of leakage from CO_2 transport, injection and sequestration sites,
- feedstock quality (e.g. carbon and energy contents),
- mining practices,
- and feedstock and fuel transport.

The first three variables likely have the largest impact in terms of energy use and GHG emissions. Emissions associated with co-products that are sold to the market can be treated using either an allocation method (by energy or mass of the products for instance) or by using a displacement method (e.g. crediting for products displaced). The first approach has the advantage of being more straightforward from an engineering standpoint. The second approach requires some understanding of the economics of the product market in order to make assumptions about the types and amount of other products that would truly be displaced. Options to co-fire biomass with coal have also been proposed but are not reviewed here. These will tend to reduce the GHG emissions relative to CTL or CTL with CCS so long as the biomass sourced minimizes indirect land use change and land use safeguards are present and enforced.

Results from three studies are presented below and include:

- GREET (version 1.8b) default results from U.S. Department of Energy's Argonne National Lab (GREET). [model results]
- Bartis, James T., Frank Camm, and David S. Ortiz (2008), "Producing Liquid Fuels from Coal: Prospects and Policy Issues," RAND Corporation.
- 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. [review study]

The U.S. EPA found that even if carbon capture and disposal technology is used to permanently capture and store 85 percent of the emissions at the production stage, liquid coal fuel could still result in 4% higher well-to-wheels CO_2 emissions compared with conventional diesel.[10] And an additional analysis conducted by the Department of Energy has shown that well-to-wheel liquid coal emissions with 85 percent carbon capture and storage could be as much as 19 to 25 percent higher than conventional gasoline/diesel.[11] However, other studies suggest that in theory, if high enough plant efficiencies and carbon sequestration rates are obtained, fuels produced from a CTL with CCS plant could have emissions

[10] Numerous process variables can affect the range of emissions. Several of these variables include the percentage of carbon capture and disposal used by the facility; the amount of leakage at the sequestration site over time; the efficiency of the plant, the type of coal used; and the products co-produced.

[11] U.S. EPA. "Greenhouse Gas Impacts of Expanded Renewable and Alternative Fuels Use." Office of Transportation and Air Quality, EPA420-F-07-035, April 2007, and Wang et. al. *Life-Cycle Energy and Greenhouse Gas Results of Fischer-Tropsch Diesel Produced from Natural Gas, Coal, and Biomass*. Department of Energy, Center for Transportation Research, Argonne National Laboratory, 2007 SAE Government/Industry Meeting, Washington, D.C., May 14-16, 2007.

similar to conventional fuels or slightly less.[12] Thus, any default emission factor should specify the specific plant configuration assumed or require actual data to be provided for verification.

Two plant configurations are presented below based on GREET 1.8b defaults. The first is a CTL plant producing only Fischer-Tropsch (FT) diesel, the second is a CTL plant producing only FT diesel but using an 85% CCS rate. All assumptions represent the defaults within GREET 1.8b, except a CCS rate of 85% versus 90% is assumed. In general, most current plant designs have not proposed using such high capture rates due to the economics. Reported capture rates typically range from 70 – 90% depending on the plant design and consideration of the economics. Generally, the overall plant emissions will tend to scale downward with the capture rate.

Two cases from the RAND (2008) study are also provided below for comparison. A range is provided in the RAND study for electricity production credit. However, the RAND analysis of producing transportation fuels from coal includes an emissions credit from electricity exports that displaces conventional coal electricity production. The credit is potentially overstated because exported electricity may be displacing natural gas or other cleaner electricity production credit. The table uses the midpoint credit value range from RAND (2008) however. The cogeneration assumption has a significant impact on the results for the CTL case with CCS, as shown in the ranges provided in the Summary Table.[13]

The CTL values below may be appropriate as a default placeholder for the fuels below, until better information or actual information can be developed. Here, we recommend that the RAND (2008) values be used as a potential placeholder or initial default value. However, we also recommend that government agencies update their value if better information and actual plant performance data becomes available. Actual plant emissions will largely depend on operating efficiencies, actual carbon capture rates, electricity coproduction, and coal type. Operators and stakeholders should outline clearly the assumptions behind estimates and ideally provide supporting data if they differ to those held by government agencies.

Table 3: Comparison of three studies for CTL production (FT-diesel shown). Units in gCO_2e/MJ finished fuel product, well-to-tank (WTT), tank-to-wheel (TTW), and well-to-wheel (WTW).

Study	Type	WTT	TTW	WTW
U.S. 2005 Avg (EPA)	Ultra Low Sulfur Diesel	17	75	92
GREET	CTL	148	75	223
GREET	CTL w/ 85% CCS	42	75	116
RAND (2008)	CTL	135	75	210
RAND (2008)	CTL w/ 85% CCS and electricity cogen credit	19	75	94
Brandt and Farrell	CTL (average value)	181	75	256

Oil Shale

Large-scale oil shale development has never gotten off the ground, largely due to substantial cost and technical challenges associated with processing the shale and safely disposing of the waste. A concerted

[12] Tarka *et al.* (2009) Affordable, Low-Carbon Diesel Fuel from Domestic Coal and Biomass (DOE/NETL-2009/1349), http://www.netl.doe.gov/energy-analyses/pubs/CBTL%20Final%20Report.pdf

[13] EPA values were assumed for the tailpipe (or tank to wheel) emissions across the comparison of studies.

attempt to develop the resource in the United State in response to the OPEC oil embargo in the 1970s famously failed in 1982 when Exxon closed the doors to its $5 billion Colony Oil Shale Plant near Parachute, Colorado.

The traditional method to extract oil shale resources is to mine it through open-pit or underground mines, crush vast amounts to the size of gravel, and then cook it in a surface retort. Modern methods have emerged that would attempt to produce oil shale in situ, or in place, by heating the shale where it lies deep underground and then extracting the liquid from the ground with conventional well technology. Experimental in situ methods have been explored at Shell's Mahogany Demonstration Project in Colorado and have been proposed for additional federal research development and demonstration (RD&D) leases in Colorado that would include heating the shale with electric resistance heaters, fracturing the shale before heating it by circulating hot CO_2 gas through the formation, or circulating superheated steam through a closed-loop system to create a "broad horizontal layer of boiling oil" deep underground, while containing the constituent parts within a manufactured freeze wall.[14]

A number of new retorting or reaction methods are currently under research and development[15]:

- Direct combustion for in situ
- Indirect heating for in situ
- Direct current heating
- RF Microwave heating for in situ
- Oil Tech Vertical Retort
- Hot gas recycle and solid-to-solid heat transfer for surface processes (Alberta Taciuk Processor and Gas Combustion Retort)

Two containment technologies are also being considered:

- Freezewall barriers for groundwater protection in in situ
- Impermeable barriers to prevent leaching and protect ground water

Regardless of whether oil shale is produced through above-ground or in situ methods, it is highly energy intensive and causes the emission of higher amounts of GHGs than conventional oil development.[16] Given the experimental nature of the technology at this stage and the absence of large-scale industrial production facilities, limited lifecycle assessments of GHG emissions from oil shale production exist. Our recommended emission factors are based on the work of Brandt (2007-2010) who has analyzed an above-ground (Alberta Taciuk Processor) and an in situ process (Shell In situ Conversion). We recommend that government agencies base their initial, default emission factors on the estimates below. However, each oil shale technology can have a distinctly different carbon footprint that depends not only on the method used, but also on the primary source of energy input (e.g. coal, natural gas, etc).

[14] This refers to proposals by Shell, Chevron, and AMSO, respectively. See Bureau of Land Management, "Environmental Assessments for Oil Shale Research, Development, and Demonstration," November 2006. http://www.co.blm.gov/wrra/wrfo_os_eas.htm.

[15] "Secure Fuels from Domestic Resources. The Continuing Evolution of America's Oil Shale and Tar Sands Industries. Profiles of Companies Engaged in Domestic Oil Shale and Tar Sands Resource and Technology Development". U.S. Department of Energy, Office of Petroleum Reserves Office of Naval Petroleum and Oil Shale Reserves; June 2007

[16] Brandt, A. R. and Farrell, A. E. Scraping the bottom of the barrel: CO2 emission consequences of a transition to low-quality and synthetic petroleum resources. Climatic Change (2007) 84:241–263.

For example, purchasing of coal-fired electricity rather than co-generating electricity on site may be more cost-effective for facilities, but lead to higher lifecycle emissions. We therefore recommend that government agencies maintain and update specific emission factors for each oil shale technology as well as key variations within specific technologies as they become available. Operators and stakeholders should outline clearly the assumptions behind estimates and ideally provide supporting data if they differ to those held by government agencies.

Above-ground processing

Above-ground processing of oil shale is currently the only method of oil shale extraction that is currently active. Active, modest ex situ operations are found in China, Brazil, and Estonia. In the context of commercial scale production, The *Alberta Taciuk Processor (ATP)* is an above-ground oil shale retort that is considered the most promising of above-ground retorts.[17] It was used in a recent oil shale development in Queensland, Australia, and Oil Sands Exploration Company (OSEC) proposed using the Processor in a 2006 application for a federal RD&D lease in Utah.[18] At least one other ATP reactor is also being constructed in China.

The Low Case assumes optimized mining, processing and other energy inputs, which will be absent given that oil shale has yet to be exploited at a large scale. We therefore believe that the High Case estimate is appropriate, and one that is comfortably in the middle of the range of published estimates.[19]

One area of research that is lacking and not incorporated into NRDC's final suggested factors is the role of other contributing greenhouse gas emissions produced in the ex situ process. Besides CO_2, the organic composition of most oil shales—when retorted—produces substantial quantities of nitrous oxide. Lifecycle analysis of the Estonian oil shale industry has shown that on average, 25% of the contributing greenhouse gas emissions produced in the retorting of Estonian oil shale can be attributed to nitrous oxide.[20] If nitrous oxide emissions are accounted for, total emissions from the ex situ process would be accordingly increased.

In situ processing

As described by Brandt[21], the *Shell In situ Conversion process (ICP)* is an experimental method of retorting oil shale without removing it from the earth. The ICP utilizes electricity to heat the underground shale slowly over a period of two years. The hydrocarbons generated are then produced using conventional oil production techniques, leaving the heavier hydrocarbons and oil shale coke within the formation.

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[17] 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.

[18] Since the RD&D lease was awarded, OSEC has announced that the company intends to deploy the Petrosix retort instead. Given that the most robust scholarship on ex situ processing has been primarily dedicated to the ATP method, and also in consideration that the ATP process does not differentiate substantially from the Petrosix process in the emissions that are rendered, this paper elects to offer conclusions derived from analyses that have investigated the ATP method.

[19] Brandt, ibid.

[20] Gavrilova *et al* (2006). Life Cycle Analysis of the Estonian Oil Shale Industry. (2006). Tallinn University of Technology. p. 45-47.

[21] Brandt, A.R. Converting oil shale to liquid fuels: Energy inputs and greenhouse gas emissions of the Shell in situ conversion process. Environmental Science & Technology 42(19) 7489-7495. (2008). DOI: 10.1021/es800531f.

Brandt's analysis is based heavily on scaling up the Oil Shale Test Project (OST), a sub-commercial-scale test of the ICP, to commercial scale operation. The OST is used because it is documented in detail in the Plan of Operations (PO) submitted by Shell to the Bureau of Land Management [46], as well as a detailed 7-volume mining operation reclamation permit application, submitted to the Colorado Division of Reclamation and Mining Safety. The ICP is also documented in a multitude of patents, totaling many thousands of pages. The patents describe a number of incarnations of the ICP, only one of which was modeled, and which represents a simplified "generic" ICP.

In this generic ICP, the bulk of the energy input for the process is in the form of electricity. Consequently, the carbon intensity of the final fuel depends primarily on the fuel sources used in the power generation mix where the oil shale is treated. In the US, the oil shale-rich areas lie in the corner of Utah, Colorado and Wyoming, and Brandt's analysis focuses on the Green River reserves of Western Colorado. The Low Case in the analysis assumes that the power source is combined cycle natural gas plants with a combined efficiency of generation and transmission of 45%. Even though in April 2010 the state of Colorado put into place new regulations that would phase out an additional 900 MW of coal fire generation currently produced by Xcel by the end of 2017, regional constraints favors access to electricity generated by coal generation based on the geographic footprint of the main oil shale resource. The High Case uses a coal mix for Colorado, and we believe that it is appropriate to base the emissions factor for ICP on this actual mix rather than a more efficient theoretical value.[22] This is a reasonable value for near-term development, given that it is most likely that projects will draw from the grid rather than build generation facilities specifically for the purpose. It should not be assumed that co-produced gas will serve as the source of power unless projects can explicitly show that this is the case.

Table 4: Emissions associated with production of diesel from oil shale. Units in gCO_2e/MJ finished fuel product, well-to-tank (WTT), tank-to-wheel (TTW), and well-to-wheel (WTW).

Source	Type	Range	Extraction & Upgrading	WTT	TTW	WTW
U.S. 2005 Baseline (EPA)	Ultra Low Sulfur Diesel			17	75	92
Brandt (2008)	Shell In-Situ	Low	30	38	75	113
		High	48	62	75	137
Brandt (2009)	ATP Ex-Situ (Above Grou	Low	52	61	75	135
		High	73	84	75	159

Errata

Version 1 of this document (dated May 2010) contained a typographical error in Table 4 for oil shale. The accompanying text and table have since been corrected.

[22] While NRDC acknowledges that electricity generated from natural gas is likely to increase its share in the region, if the Green River Basin oil shale resource was to scale to a commercial scale, it is unlikely that an oil shale industry could depend on electricity generated primarily for the public grid. As RAND has noted (Bartis, 2005), a one million bpd industry would need over 12 GW of dedicated power – equivalent to the current Colorado load. It is conceivable that economic volatility issues associated with natural gas, the low cost of coal production, and geographic proximity to available coal resources would favor at least a substantial coal mix in the long term.