Canadian Oil Sands: Life-Cycle Assessments of Greenhouse Gas Emissions

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Summary

Canadian Oil Sands and Climate Change

Recent congressional interest in U.S. energy policy has focused in part on ways through which the United States could secure more economical and reliable crude oil resources both domestically and internationally. Many forecasters identify petroleum refined from Canadian oil sands as one possible solution. Increased petroleum production from Canadian oil sands, however, is not without controversy, as many have expressed concern over the potential environmental impacts. These impacts may include emissions of greenhouse gases (GHG) during extraction and processing. A number of key studies in recent literature have expressed findings that the GHG emissions intensities of Canadian oil sands crudes may be higher than those of other crudes imported, refined, and consumed in the United States. The studies identify two main reasons for the increase: (1) oil sands are heavier and more viscous than lighter crude oil types on average, and thus require more energy- and resource-intensive activities to extract; and (2) oil sands are compositionally deficient in hydrogen, and have a higher carbon, sulfur, and heavy metal content than lighter crude oil types on average, and thus require more processing to yield consumable fuels by U.S. standards.

Selected Findings from the Primary Published Studies

CRS surveyed the published literature, including the U.S. Department of State-commissioned study in the Environmental Impact Statement for the Keystone XL pipeline project. The primary literature reveals the following:

- Canadian oil sands crudes are on average somewhat more GHG emission-intensive than the crudes they would displace in U.S. refineries, as Well-to-Wheel GHG emissions are, on average, 14%-20% higher for Canadian oil sands crude than for the weighted average of transportation fuels sold or distributed in the United States;
- discounting the final consumption phase of the life-cycle assessment (which can contribute up to 70%-80% of Well-to-Wheel emissions), Well-to-Tank (i.e., "production") GHG emissions are, on average, 72%-111% higher for Canadian oil sands crude than for the weighted average of transportation fuels sold or distributed in the United States;
- compared to selected imports, Canadian oil sands crudes range from 9% to 19% more emission-intensive than Middle Eastern Sour, 5% to 13% more emission-intensive than Mexican Maya, and 2% to 18% more emission-intensive than various Venezuelan crudes, on a Well-to-Wheel basis;
- the estimated effect of the proposed Keystone XL pipeline on the U.S. GHG footprint would be an increase of 3 million to 21 million metric tons of GHG emissions annually (equal to the annual GHG emissions from the combustion of fuels in approximately 588,000 to 4,061,000 passenger vehicles); and
- the estimated effect of the Keystone XL pipeline on global GHG emissions remains uncertain, as some speculate that its construction would encourage an expansion of oil sands development, while others suggest that the project would not substantially influence either the rate or magnitude of oil extraction activities in Canada or the overall volume of crude oil transported to and refined in the United States.

Scope and Purpose of This Report

After discussing the basic methodology of life-cycle assessments and examining the choice of boundaries, design features, and input assumptions, this report compares several of the publicly available assessments of life-cycle emissions data for Canadian oil sands crudes against each other and against those of other global reference crudes. Further, as congressional concern over the environmental impacts of Canadian oil sands production may encompass both a broad understanding of the global resource as well as a specific assessment of the proposed Keystone XL pipeline, the report surveys both the general scientific literature as well as the individual findings of the State Department's Keystone XL Project Environmental Impact Statement. Finally, as life-cycle assessments have become an influential—albeit developing—methodology for collecting, analyzing, and comparing GHG emissions, the report concludes with a discussion of some tools for policymakers who are interested in using these assessments to investigate the potential impacts of U.S. energy policy choices on the environment.

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Introduction

Recent congressional interest in U.S. energy policy has focused in part on ways through which the United States could secure more economical and reliable crude oil resources both domestically and internationally. Many forecasters identify petroleum products refined from Canadian oil sands[1] crude as one possible solution. Canadian oil sands account for about 46% of Canada's total oil production, and that number is expected to rise from its current level of 1.2 million barrels per day (mbd) to 2.8 mbd by 2015.[2] Further, the infrastructure to produce, upgrade, refine, and transport the resource from Canadian oil sands reserves to the United States is in place, and additional infrastructure projects—such as the Keystone XL pipeline—have been proposed.[3] Increased oil production from Canadian oil sands, however, is not without controversy, as many have expressed concern over the potential environmental impacts. These impacts may include increased water and natural gas use, disturbance of mined land, effects on wildlife and water quality, trans-boundary air pollution, and emissions of greenhouse gases (GHG) during extraction and processing.

A number of key studies in recent literature have expressed findings that the GHG emissions intensities of Canadian oil sands crudes may be higher than those of other crudes imported, refined, and consumed in the United States.[4] While GHG emissions and other air quality issues originating in the upstream sectors of Canada's petroleum industry may not directly impact U.S. National Emissions Inventories or U.S. GHG reporting per se, many environmental stakeholders and policymakers have noted that the increased use of more emission-intensive resources in the United States may have negative consequences for both U.S. and global energy policy and environmental compliance.

The U.S. Department of State (DOS), in response to comments on the draft Environmental Impact Statement (EIS) for the Keystone XL pipeline project (which would connect oil sands production facilities in the Western Canadian Sedimentary Basin with refinery facilities in the United States), commissioned a contractor's study on the GHG life-cycle emissions associated with these resources in comparison to other reference crudes.[5] DOS presented this analysis in the Final EIS as a "matter of policy," and noted that neither the National Environmental Policy Act (NEPA) nor DOS regulations (22 C.F.R. 161.12) nor Executive Orders 13337 and 12114 (Environmental Effects Abroad of Major Federal Activities) legally require that an EIS include an assessment of environmental activities outside the United States. In the Final EIS, DOS supported the claim that while the proposed Keystone XL pipeline project may contribute to certain trans-boundary and continental scale environmental impacts, it may not substantially influence either

[1] The resource has been referred to by several terms, including oil sands, tar sands, and, most technically, bituminous sands. Because of its widespread use in academic literature, the term "oil sands" is used in this report.

[2] For more information on oil sands resources, see CRS Report RL34258, *North American Oil Sands: History of Development, Prospects for the Future*, by Marc Humphries.

[3] For a full analysis of TransCanada's Keystone XL Pipeline project, see CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by Paul W. Parfomak et al., and CRS Report R42124, *Proposed Keystone XL Pipeline: Legal Issues*, by Adam Vann et al.

[4] A list of studies surveyed in this report can be found in **Table 1**; an account of the finding can be found in **Table 2**.

[5] The full report by the State Department's contractor, ICF International LLC, is found in U.S. Department of State, *Keystone XL Project, Final Environmental Impact Statement, Appendix V*, "Life-Cycle Greenhouse Gas Emissions of Petroleum Products from WCSB Oil Sands Crudes Compared with Reference Crudes," July 13, 2011, at http://www.keystonepipeline-xl.state.gov/.

the rate or magnitude of oil extraction activities in Canada or the overall volume of crude oil transported to and refined in the United States.[6]

This report presents a summary of life-cycle emissions assessments of Canadian oil sands crudes and provides an analysis of their respective findings. The first section of the report, "Life-Cycle Assessment Methodology," discusses the basic methodology of life-cycle assessments and examines the choice of boundaries, design features, and input assumptions. The second section of the report, "Results of Selected Life-Cycle Emissions Assessments," compares several of the publicly available assessments of life-cycle GHG emissions data for Canadian oil sands crudes against each other, against those of other global reference crudes, and against those of other fossil fuel resources. The third section, "U.S. Carbon Footprint for the Keystone XL Pipeline," examines some of the specific findings of the Department of State's commissioned study for the Keystone XL pipeline. The report concludes with a discussion of some tools for policymakers who are interested in using these assessments to investigate the potential impacts of U.S. energy policy choices on the environment.

Life-Cycle Assessment Methodology

Life-cycle assessment (LCA) is an analytic method used for evaluating and comparing the environmental impacts of various products (in this case, the climate change implications of hydrocarbon resources). LCAs can be used in this way to identify, quantify, and track emissions of carbon dioxide and other GHG emissions arising from the development of these hydrocarbon resources, and to express them in a single, universal metric of carbon dioxide equivalent (CO_2e) GHG emissions per unit of fuel or fuel use.[7] This figure is commonly referred to as the "emissions intensity" of the fuel. The results of an LCA can be used to evaluate the GHG emissions intensity of various stages of the fuel's life cycle, as well as to compare the emissions intensity of one type of fuel or method of production to another.

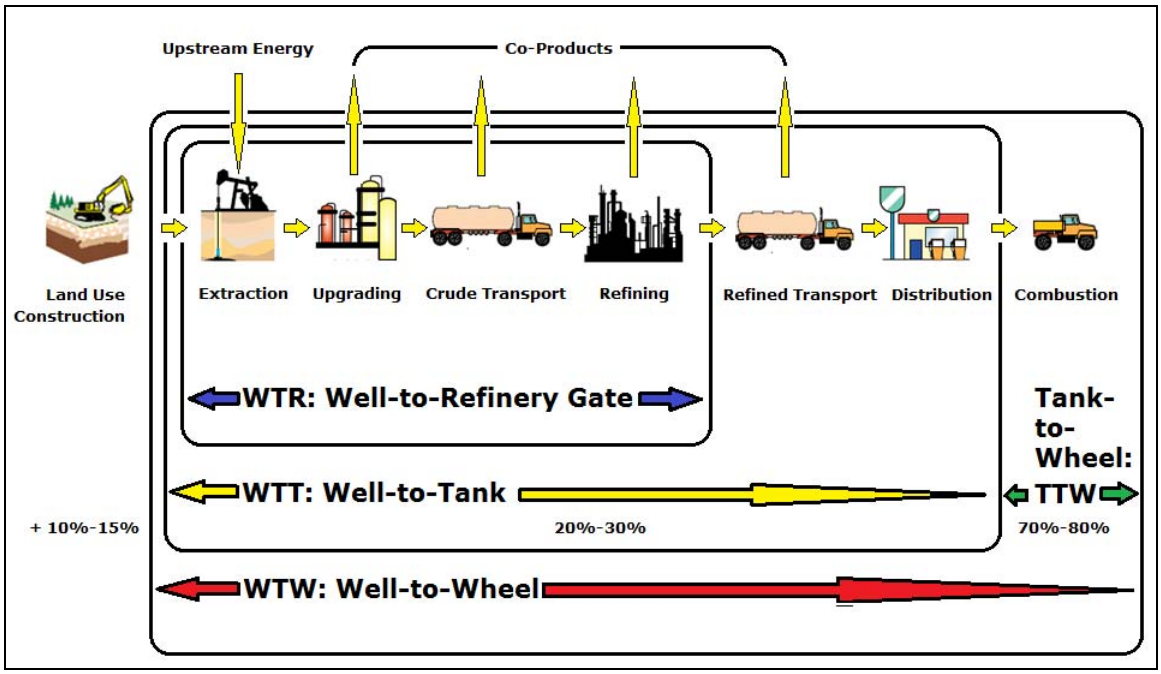
GHG emissions profiles modeled by most LCAs are based on a set of boundaries commonly referred to as "cradle-to-grave," or, in the case of transportation fuels such as petroleum, "Well-to-Wheel" (WTW). WTW assessments for petroleum-based transportation fuels focus on the emissions associated with the entire life cycle of the fuel, from extraction, transport, and refining of crude oil; to the distribution of refined product (e.g., gasoline, diesel, jet fuel) to retail markets; to the combustion of the fuel in end-use vehicles. Other LCAs (e.g., Well-to-Tank [WTT] or Well-to-Refinery Gate [WTR]) establish different (i.e., more specific) life-cycle boundaries to evaluate emissions (see **Figure 1**). Inclusion of the final combustion phase allows for the most complete picture of crude oil's impact on GHG emissions, as this phase can contribute up to 70%-80% of WTW emissions. However, other LCAs can be used to highlight the differences in emissions

[6] Several of the studies, however, question this finding, and in particular, whether the production of Canadian oil sands crude would be economically viable if not exported through pipelines to the United States. See, for example, Natural Resources Defense Council, "Say No to Tar Sands Pipeline," March 2011, at http://www.nrdc.org/land/files/TarSandsPipeline4pgr.pdf.

[7] Greenhouse gases include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6), among many others. In order to compare and aggregate different greenhouse gases, various techniques have been developed to index the effect each greenhouse gas has to that of carbon dioxide, where the effect of CO_2 equals one. When the various gases are indexed and aggregated, their combined quantity is described as the CO_2-equivalent. In other words, the CO_2-equivalent quantity would have the same effect on, say, radiative forcing of the climate, as the same quantity of CO_2.

associated with particular stages as well as experiment with certain boundary assumptions. The choice of boundaries is an important component to any LCA and can lead to vastly differing reported results.[8]

Figure 1. Crude Oil Life-Cycle Schematic



Source: CRS.

Because of the complex life cycle of hydrocarbon fuels and the large number of analytical design features that are needed to model their emissions, LCAs must negotiate many variables and uncertainties in available data. Key factors that influence the results of an LCA include (1) composition of the resource that is modeled, (2) extraction process of the resource that is modeled, (3) design factors chosen for the assessment, and (4) assumptions made in the input data for the assessment.

Crude Oil Types. Oil sands are a type of unconventional petroleum deposit. They are commonly loose sand or partially consolidated sandstone containing naturally occurring mixtures of sand, clay, and water, as well as a dense and extremely viscous form of petroleum technically referred to as bitumen.[9] Most LCAs do not include an assessment of raw bitumen, because it is near solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. Thus, bitumen is often diluted with liquid hydrocarbons or converted into a synthetic light crude oil to produce the resource known as oil sands crude. Several kinds of crude-like

[8] A study's choice of boundaries is responsible for many of the vastly differing values for GHG emissions intensities that are currently being reported in published studies of the Canadian oil sands relative to other reference crudes. For example, when expressed on a WTT basis rather than on a WTW basis, GHG emissions intensities from Canadian oil sands crudes may show values that are significantly higher than reference crudes due to the technical omission of combustion from the calculation (see the reported findings in subsequent sections for examples).

[9] For more technical information on bitumen, see CRS Report RL34258, *North American Oil Sands: History of Development, Prospects for the Future*, by Marc Humphries; and, for example, National Petroleum Council, *Heavy Oil, Topic Paper #22,* July 18, 2007, at http://www.npc.org/study_topic_papers/22-ttg-heavy-oil.pdf.

products can be generated from bitumen, and their properties differ in some respects from conventional light crude. They include the following:

- **Upgraded Bitumen, or Synthetic Crude Oil (SCO).** SCO is produced from bitumen through an upgrading process that turns the very heavy hydrocarbons into lighter fractions. Since the upgrading process begins at the production facility for SCO, the allocation of GHG emissions is weighted more heavily upstream than other crude types.
- **Diluted Bitumen (Dilbit).** Dilbit is bitumen mixed with diluents—typically natural gas liquids such as condensate—to create a lighter, less viscous, and more easily transportable product. Mixing bitumen with less carbon-intensive diluents lessens the GHG emissions impact per barrel of dilbit in relation to bitumen or SCO. Some refineries need modifications to process large quantities of dilbit feedstock, since it requires more heavy oil conversion capacity than conventional crudes. Increased processing in refineries shifts GHG emissions downstream, potentially intensifying the downstream GHG emission impact of dilbit in relation to SCO or other crudes (e.g., if dilbit is transported from Canada to the United States via a pipeline, the need for increased refining downstream would shift the potential for emissions to the United States).
- **Synthetic Bitumen (Synbit).** Synbit is typically a combination of bitumen and SCO. The properties of each kind of synbit blend vary significantly, but blending the lighter SCO with the heavier bitumen results in a product that more closely resembles conventional crude oil. Refining emissions from synbit occur both upstream and downstream, depending upon a variety of factors.

Extraction Process. Two types of methods for extracting bitumen from the reservoir are currently used in the Canadian oil sands. They include the following:

- **Mining.** Oil sands deposits that are less than approximately 75 meters below the surface can readily be removed using conventional strip-mining methods. An estimated 20% of currently recoverable reserves are close enough to be mined. The strip-mining process includes removal of the overburden (i.e., primary soils and vegetation), excavation of the resource, and transportation to a processing facility. Higher intensities of GHG emissions may result from increased land use changes during strip-mining. Mining accounts for slightly more than 50% of current production, and is expected to remain between 40% and 50% through 2030.[10]
- **In-Situ.** Oil sands deposits that are deeper than approximately 75 meters are recovered using in-situ methods. Most in-situ recovery methods currently in operation involve injecting steam into an oil sands reservoir to heat—and thus decrease the viscosity of—the bitumen, enabling it to flow out of the reservoir to collection wells. Steam is injected using cyclic steam stimulation (CSS), where the same well cycles both the steam and the bitumen, or by steam-assisted gravity drainage (SAGD), where a top well is used for steam injection and the bottom

[10] Predictions range from 50% in IHS CERA, *Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right*, IHS Cambridge Energy Research Associates, Inc., 2010, to 40% in Canadian Association of Petroleum Producers, "Crude Oil Forecast," June 2011.

well is used for bitumen recovery. Because significant amounts of energy are currently required to create steam, in-situ methods are generally more GHG-intensive than conventional mining (excluding land use impacts). With over 80% of recoverable reserves situated too deep for conventional mining techniques, it is assumed that the industry will eventually move toward an increased use of the in-situ extraction process in some form.

Study Design Factors. Design factors relate to how the GHG comparison is structured in each study and which parameters are included. These factors may include

- overall purpose and goal of the study,
- time frame for the inputs and the results,
- life-cycle boundaries that are established for comparison,
- units and metrics used for comparison,
- GHG global-warming potential used for comparison,[11]
- treatment of co-products during refining (e.g., asphalt, petroleum coke, liquid gases, lubricants),
- treatment of secondary emission flows (e.g., capital infrastructure, land-use changes),[12]
- treatment of power co-generation at the facilities, and
- treatment of flaring, venting, and fugitive emissions.

Input Assumptions. Input assumptions can impact life-cycle results at each stage of the assessment. Studies often use simplified assumptions to model GHG emissions due to limited data availability and the complexity of and variability in the practices used to extract, process, refine, and transport crude oil, diluted crude, or refined product. Key input assumptions for Canadian oil sands crude may include

- percentage contribution of each type of crude and each type of extraction process in the final transported product;
- type of upgrading or refining processes;
- amount of petroleum coke produced, stored, combusted, or sold;
- ratios for bitumen-to-diluents, steam-to-oil, gas-to-oil, water-to-oil; and
- energy efficiencies for steam generation and other production processes.

[11] Global-warming potential (GWP) is a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide. A GWP is calculated over a specific time interval, commonly 20, 100, or 500 years. All data included in this report use a 100-year time interval.

[12] LCAs often characterize emissions into primary and secondary flows. Primary flows are associated with the various stages in the hydrocarbon life cycle, from extraction of the resource to the combustion of the final refined fuel. Primary flows are generally well understood and included in most LCAs. Secondary flows are associated with activities not directly related to the conversion of the hydrocarbon resource into useful product (e.g., local and indirect land-use changes, construction emissions, etc.). Because these flows are outside the primary operations, they are often characterized differently across studies or excluded from LCAs altogether.

Results of Selected Life-Cycle Emissions Assessments

Life-Cycle Assessments of Canadian Oil Sands

Greenhouse gases, primarily in the form of carbon dioxide and methane, are emitted during a variety of stages in oil sands production (see text box below).[13] A number of published and publicly available studies have attempted to assess the life-cycle GHG emissions data for Canadian oil sands crudes. This report examines the life-cycle assessments analyzed by the U.S. Department of State (DOS)—in conjunction with the consultancy firm ICF International LLC (ICF)—in the Keystone XL Project's Final Environmental Impact Statement (Final EIS). The studies were selected by ICF using several criteria: (1) they evaluated Canadian oil sands crudes in comparison to other reference crude oils, (2) they focused on GHG emissions impacts throughout the entire crude oil life-cycle, (3) they were published within the past 10 years, and (4) they represented the perspectives of a range of stakeholders.

Summary of the Potential Sources of GHG Emissions in Oil Sands Development

- land use changes (emissions from the removal of vegetation and trees, soil, and peatland for mining or facilities),
- capital equipment (emissions from the construction of facilities, machinery, or other infrastructure),
- upstream fuels (emissions from the upstream production of fuel or electricity that is imported to the facility to be used as process heat or power for machinery),
- extraction (emissions from the bitumen extraction process, including equipment for mining and steam generation for artificial lifting),
- upgrading (emissions from the bitumen upgrading process and the combustion of co-products),
- crude product transportation (emissions from the transportation of crude products and co-products),
- refining (emissions from the crude oil refining process and the combustion of co-products),
- fugitives (emissions from the venting or flaring of methane, or fugitive leaks at any stage of production),
- refined product transportation (emissions from the transportation of final refined products and co-products), and
- combustion (emissions from the end-use combustion of the refined fuel and co-products).

Table 1 provides a list of the studies referenced by the ICF analysis. While the type, boundaries, and design features vary across all studies, DOS and ICF determined the data and results from AERI/Jacobs 2009, AERI/TIAX 2009, NETL 2008, and NETL 2009 to be sufficiently robust for inclusion in the Final EIS. Reasons against the inclusion of the remaining studies are presented briefly in the table, and outlined in more detail in the Final EIS.

[13] For a discussion of the role and effects of greenhouse gases in climate change, see CRS Report RL34266, *Climate Change: Science Highlights*, by Jane A. Leggett.

Table 1. Life-Cycle Assessments of Canadian Oil Sands

As evaluated by DOS/ICF for inclusion in the Keystone XL Project Final EIS

Study	Reference Years	Type	Boundaries	Design Factors
Primary LCAs, the data from which are included in the Final EIS				
AERI/Jacobs 2009	2000s	LCA	WTW	All crudes
AERI/TIAX 2009	2007-2009	LCA	WTW	All crudes
NETL 2008	2005	LCA	WTW	All crudes
NETL 2009	2005	LCA	WTW	All crudes
Other studies, the data from which are not included in the Final EIS				
Charpentier 2009	1999-2008	Meta-analysis	WTW	Dilbit not analyzed
GREET 2010	Current	Model	WTW	SCO and dilbit unspecified
ICCT 2010	2009	Partial LCA	WTT	Only imports to Europe analyzed
IEA 2010	2005-2009	Meta-analysis	WTW	Crude type not specified, results compared on a per barrel basis
IHS CERA 2010	2005-2030	Meta-analysis	WTW	All crudes, results compared on a per barrel basis
McCann 2001	2007	LCA	WTW	SCO only, results compared on a per liter basis
McCulloch/Pembina 2006	2002-2005	Partial LCA	WTR	SCO only, results compared on a per barrel basis
NRCan 2008	2008	LCA	WTW	Bitumen only, dilbit not analyzed
NRDC 2010	2006-2010	Meta-analysis	WTW	All crudes
Pembina 2005	2000, 2004	Partial LCA	WTR	Crude composition not specified
RAND 2008	2000s	LCA	WTR	SCO only

Sources: Alberta Energy Research Institute/Jacobs Consultancy, *Life Cycle Assessment Comparison of North American and Imported Crudes*, 2009; Alberta Energy Research Institute/TIAX LLC, *Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions*, 2009; National Energy Technology Laboratory, *Development of Baseline Data and Assessment of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 26, 2008; National Energy Technology Laboratory, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions*, March 27, 2009; Charpentier, A., et al., "Understanding the Canadian Oil Sands Industry's Greenhouse Gas Emissions," *Environmental Research Letters*, Vol. 4, January 20, 2009; GREET, *Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model*, Version 1.8d.1, Argonne National Laboratory, 2010; International Council on Clean Transportation, *Carbon Intensity of Crude Oil in Europe Crude*, 2010; International Energy Agency, World Energy Outlook, 2010; IHS Cambridge Energy Research Associates, Inc., *Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right*, 2010; T. J. McCann and Associates Ltd., *Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles in 2007*, Prepared for Regional Infrastructure Working Group, November 16, 2001; McCulloch, M., et al., *Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands*, Oil Sands Issue Paper No. 2, Pembina Institute, October 2006; Natural Resources Canada /(S&T)^2 Consultants, *2008 GHGenius Update*, August 15, 2008; Natural Resources Defense Council, *GHG Emission Factors for High Carbon Intensity Crude Oils*, Ver. 2, September 2010; Pembina Institute, *Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush*, November 2005; RAND Corporation. *Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs*, 2008.

Notes: According to the DOS/ICF evaluation: "Type" is considered sufficient when the study is a unique, original assessment, and is not a meta-analysis that summarizes and averages the results from other sources; "Boundaries" is considered sufficient when the study evaluates the full WTW GHG emissions life cycle; "Design Factors" is considered sufficient when the study includes and evaluates all crude types likely to be transported by the Keystone XL pipeline. See DOS Final EIS, p. 40, for more on the DOS evaluation of each study.

Findings

Using data from the primary studies, the DOS/ICF analysis in the Final EIS finds the following:

- Comparisons across the published studies of GHG life-cycle emissions intensities for fuels derived from different sources are sensitive to each study's choice of boundaries and input parameters.
- Well-to-Wheel GHG emissions are valued at 91 gCO_2e/megajoule (MJ) lower heating value (LHV)[14] gasoline for the weighted average[15] of transportation fuels sold or distributed in the United States (in reference year 2005).[16]
- Well-to-Wheel GHG emissions are valued between 104-109 gCO_2e/MJ LHV gasoline for the weighted average of Canadian oil sands crudes likely to be transported in the proposed Keystone XL pipeline project in the near term.
- Well-to-Wheel GHG emissions are, on average, 14%-20% higher for Canadian oil sands crude than for the weighted average of transportation fuels sold or distributed in the United States (in reference year 2005);
- Well-to-Tank (i.e., "production") GHG emissions are, on average, 72%-111% higher for Canadian oil sands crude than for the weighted average of transportation fuels sold or distributed in the United States (in 2005);

The DOS/ICF study is not an independent and original assessment, but a comparative analysis of multiple other studies, each presenting significant variations both of reported findings and of design and input assumptions. Similar to other meta-analyses (e.g., NRDC 2010, IHS CERA 2010), attempts have been made to synthesize and normalize data from the other studies, but the assessments may not be fully compatible. The numbers listed above serve as averages, and are intended to reflect the range of estimates from the primary studies. Conversely, individual estimates reported by each of the studies listed in **Table 1**—both primary and secondary—for various Canadian oil sands crude types and production processes can be found in **Figure 2** and **Table 2**.

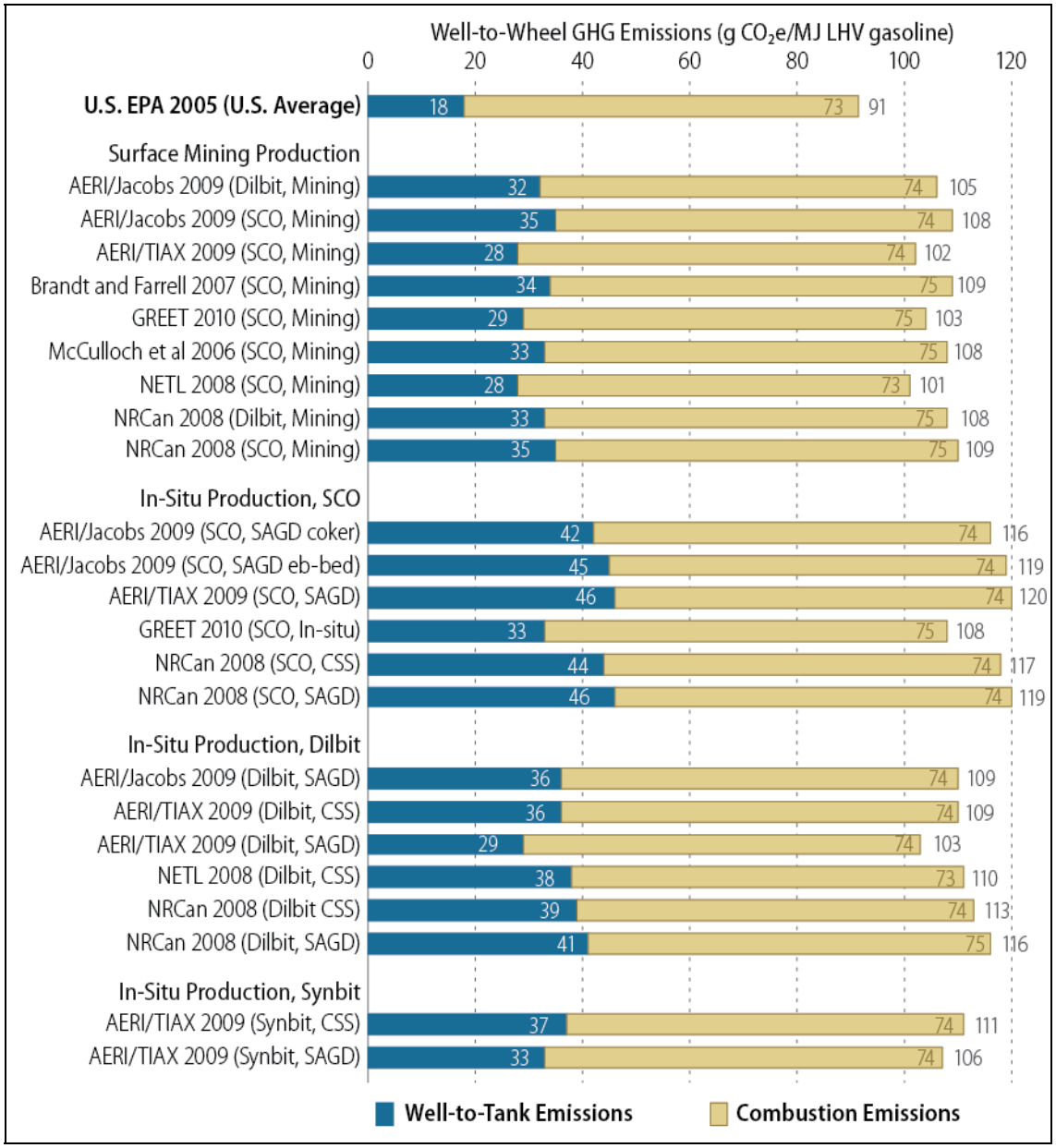
[14] The heating value or energy value of gasoline is the amount of heat released during the combustion of a specified amount of it. The quantity known as higher heating value (HHV) is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular condensing any vapor produced. The quantity known as lower heating value (LHV) assumes that the latent heat of vaporization of water in the fuel and the reaction products is not recovered. LHV is useful in comparing transportation fuels because condensation of the combustion products is not practical.

[15] Weighted average computations refer to the assumed mix of crude types and production processes that make up the bulk of a final product. The assumptions are based on reported industry practices, and are modeled differently in each study. See ICF 2011 for its modeling assumptions. For example, calculations for the weighted average for "transportation fuels sold or distributed in the United States" in 2005 can be found in NETL 2008. IHS CERA 2010 assumes an average 55% dilbit and 45% SCO for oil sands imported to United States, and NETL 2008 assumes 57% SCO and 43% crude bitumen. In the Final EIS, DOS assumes that the average crude oil flowing through the pipeline would consist of about 50% Western Canadian Select (dilbit) and 50% Suncor Synthetic A (SCO).

[16] This baseline is from NETL 2008. It assesses "the average life cycle GHG profile for transportation fuels sold or distributed in the United States in 2005 [and] is determined based on the weighted average of fuels produced in the U.S. plus fuels imported into the U.S. minus fuels produced in the U.S. but exported to other countries for use" (NETL 2008, p. ES-5). It includes Canadian oil sands, but does not include emissions from some of the most carbon-intensive imported crude oils (e.g., Venezuelan Heavy) due to modeling uncertainties (NETL 2008, p. ES-7; NETL 2009, p. ES-2). The baseline value is consistent with the definitions for "baseline life-cycle greenhouse gas emissions" as used in the Energy Independence and Security Act (EISA) of 2007 and the U.S. Renewable Fuel Standards Program of 2010.

Figure 2 presents a summary of the WTW GHG emissions estimates as reported by each of the studies for various Canadian oil sands crude types and production processes. **Table 2** summarizes and compares each study's emissions estimates, data, and relevant input assumptions. Individual estimates for different crude types and different production processes range from increases of 1%-41% over the baseline. Variability among the estimates is, in part, the result of each study's differing design and input assumptions. A discussion of these assumptions—and their estimated impacts on GHG emissions—follows in the next section.

Figure 2. Well-to-Wheel GHG Emissions Estimates for Canadian Oil Sands Crudes



Source: CRS, from studies outlined in **Table 1**. Average U.S. petroleum baseline for 2005 provided by U.S. Environmental Protection Agency (U.S. EPA), *Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis*, February 2010, EPA-420-R-10-006, with data sourced from DOE/NETL, *Development of Baseline Data and Analysis of Life Cycle GHG Emissions of Petroleum Based Fuels*, November 2008.

Notes: See section "Life-Cycle Assessment Methodology" for key to crude oil types and production processes. U.S. EPA 2005 (U.S. Average) assesses "the average life cycle GHG profile for transportation fuels sold or distributed in the United States in 2005 [and] is determined based on the weighted average of fuels produced in the U.S. plus fuels imported into the U.S. minus fuels produced in the U.S. but exported to other countries for use" (NETL 2008, p. ES-5). This baseline includes Canadian oil sands, but does not include emissions from some of the most carbon-intensive imported crude oils (e.g., Venezuelan Heavy) due to modeling uncertainties (NETL 2008, p. ES-7; NETL 2009, p. ES-2).

Table 2. Reported Findings of Well-to-Wheel GHG Emissions Estimates in the Life-Cycle Assessments of Canadian Oil Sands Crudes

Study	Production Method	Crude Type	WTW GHG Emissions	Increase over Baseline	Key Assumptions
LCAs analyzed by ICF 2011					
WTW GHG emissions expressed in gCO_2e/MJ LHV gasoline					
U.S. EPA 2005	Baseline	Varied	91	—	Baseline assesses "the average life cycle GHG profile for transportation fuels sold or distributed in the United States in 2005 [and] is determined based on the weighted average of fuels produced in the U.S. plus fuels imported into the U.S. minus fuels produced in the U.S. but exported to other countries for use" (NETL 2008, p. ES-5). This baseline includes Canadian oil sands, but does not include emissions from some of the most carbon-intensive imported crude oils (e.g., Venezuelan Heavy) due to modeling uncertainties (NETL 2008, p. ES-7; NETL 2009, p. ES-2).
AERI/Jacobs 2009	Mining + Upgrading	SCO	108	19%	Units: gCO_2e/MJ reformulated gasoline; petroleum coke stored at upgrader; petroleum coke production emissions at the refinery allocated to the premium fuel products and sold as a substitute for coal in electricity generation; accounting for upgrading included in refinery emissions; emissions from upstream fuel production included; venting and flaring included; infrastructure and land-use changes not specified or not included.
AERI/Jacobs 2009	Mining	Dilbit	105	15%	Units: gCO_2e/MJ reformulated gasoline; diluents processed with bitumen at refinery; petroleum coke production emissions at the refinery allocated to the premium fuel products and sold as a substitute for coal in electricity generation; emissions from upstream fuel production included; venting and flaring included; infrastructure and land-use changes not specified or not included.

Study	Production Method	Crude Type	WTW GHG Emissions	Increase over Baseline	Key Assumptions
AERI/Jacobs 2009	In-Situ, SAGD + Upgrading (Hydrocracking)	SCO	119	31%	Units: gCO_2e/MJ reformulated gasoline; steam-to-oil ratio (SOR) of 3; petroleum coke stored at upgrader; petroleum coke production emissions at the refinery allocated to the premium fuel products and sold as a substitute for coal in electricity generation; cogeneration credits applied; accounting for upgrading included in refinery emissions; emissions from upstream fuel production included; venting and flaring included; infrastructure and land-use changes not specified or not included.
AERI/Jacobs 2009	In-Situ, SAGD + Upgrading (Coker)	SCO	116	27%	Units: gCO_2e/MJ reformulated gasoline; SOR 3; petroleum coke stored at upgrader; petroleum coke production emissions at the refinery allocated to the premium fuel products and sold as a substitute for coal in electricity generation; cogeneration credits applied; accounting for upgrading included in refinery emissions; emissions from upstream fuel production included; venting and flaring included; infrastructure and land-use changes not specified or not included.
AERI/Jacobs 2009	In-Situ, SAGD	Dilbit	105-113	15%-24%	Units: gCO_2e/MJ reformulated gasoline; SOR 3; cogeneration credits applied; diluents processed with bitumen at refinery; petroleum coke production emissions at the refinery allocated to the premium fuel products and sold as a substitute for coal in electricity generation; emissions from upstream fuel production included; venting and flaring included; infrastructure and land-use changes not specified or not included.
AERI/TIAX 2009	Mining + Upgrading	SCO	102	12%	Units: gCO_2e/MJ reformulated gasoline; petroleum coke production emissions at upgrader allocated in part to the coke and outside LCA; petroleum coke combustion emissions at upgrader not included; petroleum coke production emissions at the refinery allocated to the premium fuel products; petroleum coke combustion emissions at refinery not included; accounting for upgrading included in refinery emissions; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.

Study	Production Method	Crude Type	WTW GHG Emissions	Increase over Baseline	Key Assumptions
AERI/TIAX 2009	In-Situ, SAGD + Upgrading	SCO	112-128	23%-41%	Units: gCO_2e/MJ reformulated gasoline; SOR 2.5; petroleum coke production emissions at upgrader allocated in part to the coke and outside LCA; petroleum coke combustion emissions at upgrader not included; cogeneration credits applied using project specific data; petroleum coke production emissions at the refinery allocated to the premium fuel products; petroleum coke combustion emissions at refinery not included; accounting for upgrading included in refinery emissions; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
AERI/TIAX 2009	In-Situ, SAGD	Synbit	105-108	15%-19%	Units: gCO_2e/MJ reformulated gasoline; SOR 2.5; cogeneration credits applied using project specific data; petroleum coke production emissions at the refinery allocated to the premium fuel products; petroleum coke combustion emissions at refinery not included; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
AERI/TIAX 2009	In-Situ, SAGD	Dilbit	101-105	11%-15%	Units: gCO_2e/MJ reformulated gasoline; SOR 2.5; cogeneration credits applied using project specific data; diluents processed with bitumen at refinery; petroleum coke production emissions at the refinery allocated to the premium fuel products; petroleum coke combustion emissions at refinery not included; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
AERI/TIAX 2009	In-Situ, CSS	Synbit	109-112	20%-23%	Units: gCO_2e/MJ reformulated gasoline; SOR 3.4-4.8; cogeneration credits applied using project specific data; petroleum coke production emissions at the refinery allocated to the premium fuel products; petroleum coke combustion emissions at refinery not included; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.

Study	Production Method	Crude Type	WTW GHG Emissions	Increase over Baseline	Key Assumptions
AERI/TIAX 2009	In-Situ, CSS	Dilbit	107-112	18%-23%	Units: gCO_2e/MJ reformulated gasoline; SOR 3.4-4.8; cogeneration credits applied using project specific data; diluents processed with bitumen at refinery; petroleum coke production emissions at the refinery allocated to the premium fuel products; petroleum coke combustion emissions at refinery not included; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
NETL 2008	Mining + Upgrading	SCO	101	11%	Units: gCO_2e/MMBtu gasoline, diesel, and jet fuel; petroleum coke use unspecified at upgrader, petroleum coke production emissions at refinery allocated outside LCA; petroleum coke combustion emissions at refinery allocated only if combusted on site; accounting for upgrading not included in refinery emissions; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
NETL 2008	In-Situ, CSS	Dilbit	110	21%	Units: gCO_2e/MMBtu gasoline, diesel, and jet fuel; SOR not stated; cogeneration unspecified; diluents unspecified; petroleum coke production emissions at refinery allocated outside LCA; petroleum coke combustion emissions at refinery allocated only if combusted on site; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
Additional LCAs analyzed by NRDC 2010					
WTW GHG emissions expressed in gCO_2e/MJ LHV gasoline					
U.S. EPA 2005	Baseline	Varied	93	—	Baseline assesses "the average life cycle GHG profile for transportation fuels sold or distributed in the United States in 2005 [and] is determined based on the weighted average of fuels produced in the U.S. plus fuels imported into the U.S. minus fuels produced in the U.S. but exported to other countries for use" (NETL 2008, p. ES-5). Includes emissions from higher carbon-intensity crude oils imported or produced domestically.

Study	Production Method	Crude Type	WTW GHG Emissions	Increase over Baseline	Key Assumptions
GREET 2010	Mining + Upgrading	SCO	103	11%	Units: gCO_2e/mile; petroleum coke use unspecified; accounting for upgrading not included in refinery emissions; emissions from upstream fuel production not specified; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
GREET 2010	In-Situ, SAGD + Upgrading	SCO	108	16%	Units: gCO_2e/mile; SOR not stated; petroleum coke use unspecified; cogeneration unspecified; accounting for upgrading not included in refinery emissions; emissions from upstream fuel production not specified; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
McCulloch 2006	Mining + Upgrading	SCO	105-111	13%-19%	Units: $kgCO_2e$/bbl SCO; petroleum coke gasification at upgrader included in high estimate, unspecified at the refinery; accounting for upgrading not specified in refinery emissions; emissions from upstream fuel production not specified; venting, flaring, and fugitives partially included; infrastructure and land-use changes not specified or not included.
NRCan 2008	Mining + Upgrading	SCO	109	17%	Units: gCO_2e/MJ reformulated gasoline; petroleum coke used at the upgrader contributes 15% of the energy requirement for processing SCO and the remainder offsets emissions from coal combustion at electric generating units, not specified at refinery; accounting for upgrading not included in refinery emissions; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
NRCan 2008	Mining	Dilbit	108	16%	Units: gCO_2e/MJ reformulated gasoline; diluents unspecified; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.

Study	Production Method	Crude Type	WTW GHG Emissions	Increase over Baseline	Key Assumptions
NRCan 2008	In-Situ, SAGD + Upgrading	SCO	119	28%	Units: gCO_2e/MJ reformulated gasoline; SOR 3.2; petroleum coke used at the upgrader contributes 15% of the energy requirement for processing SCO and the remainder offsets emissions from coal combustion at electric generating units, not specified at refinery; cogeneration not included; accounting for upgrading not included in refinery emissions; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
NRCan 2008	In-Situ, SAGD	Dilbit	116	25%	Units: gCO_2e/MJ reformulated gasoline; SOR 3.2; cogeneration not included; diluents unspecified; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
NRCan 2008	In-Situ, CSS + Upgrading	SCO	117	26%	Units: gCO_2e/MJ reformulated gasoline; SOR not stated; petroleum coke used at the upgrader contributes 15% of the energy requirement for processing SCO and the remainder offsets emissions from coal combustion at electric generating units, not specified at refinery; cogeneration not included; accounting for upgrading not included in refinery emissions; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
NRCan 2008	In-Situ, CSS	Dilbit	113	22%	Units: gCO_2e/MJ reformulated gasoline; SOR not stated; cogeneration not included; diluents unspecified; emissions from upstream fuel production included; venting, flaring, and fugitives included; infrastructure and land-use changes not specified or not included.
Additional LCAs analyzed by IHS CERA 2010					
WTW GHG emissions expressed in $KgCO_2e$/barrel of refined product (see notes below)					
IHS CERA, 2010	Average US Barrel Consumed	Varied	487	—	As modeled by IHS CERA from data sourced from NETL 2008.
IHS CERA, 2010	Mining	Dilbit	488	<1%	Units: $kgCO_2e$ per barrel of refined products; diluents processed with bitumen at refinery; emissions from upstream fuel production not included; venting, flaring, and fugitives not specified; infrastructure and land-use changes not specified or not included.

Study	Production Method	Crude Type	WTW GHG Emissions	Increase over Baseline	Key Assumptions
IHS CERA, 2010	Mining + Upgrading (Coker)	SCO	518	6%	Units: $kgCO_2e$ per barrel of refined products; petroleum coke use unspecified at the upgrader, allocated outside LCA at refinery; accounting for upgrading not specified in refinery emissions; emissions from upstream fuel production not included; venting, flaring, and fugitives not specified; infrastructure and land-use changes not specified or not included.
IHS CERA, 2010	In-Situ, SAGD	Dilbit	512	5%	Units: $kgCO_2e$ per barrel of refined products; SOR 3; cogeneration credits applied; diluents processed with bitumen at refinery; emissions from upstream fuel production not included; venting, flaring, and fugitives not specified; infrastructure and land-use changes not specified or not included.
IHS CERA, 2010	In-Situ, SAGD + Upgrading	SCO	555	14%	Units: $kgCO_2e$ per barrel of refined products; SOR 3; petroleum coke use unspecified at the upgrader, allocated outside LCA at refinery; cogeneration credits applied; accounting for upgrading not specified in refinery emissions; emissions from upstream fuel production not included; venting, flaring, and fugitives not specified; infrastructure and land-use changes not specified or not included.

Sources: CRS, from studies outlined in **Table 1**. Average U.S. petroleum baseline for 2005 provided by U.S. EPA, *Renewable Fuel Standard Program (RFS2): Regulatory Impact Analysis*, February 2010, EPA-420-R-10-006, with data sourced from DOE/NETL, *Development of Baseline Data and Analysis of Life Cycle GHG Emissions of Petroleum Based Fuels*, November 2008.

Notes: See section "Life-Cycle Assessment Methodology" for key to crude oil types and production processes. ICF 2011 and the LCAs it reviewed, as well as NRDC 2010, expressed functional units in GHG emissions per megajoule (MJ) of gasoline, per MJ of diesel, and per MJ of jet fuel (the gasoline values are shown in this report). IHS CERA 2010, in contrast, expressed GHG emissions in units of kilograms of carbon dioxide equivalent per barrel of refined product produced, ($kgCO_2e$ per barrel of refined products). Refined products are defined by IHS CERA as "the yield of gasoline, diesel, distillate, and gas liquids from each crude." As a meta-analysis, IHS CERA 2010 used the results of the existing and publicly available life-cycle assessments, including many of those listed in **Table 1**; however, a demonstration of the unit conversions was not provided. Without detail of the underlying allocation methods used to aggregate the gasoline, diesel, jet fuel, and other co-products, neither CRS nor the DOS/ICF report was able to convert and directly compare IHS CERA's functional units to the other studies.

Design Factors and Input Assumptions for Canadian Oil Sands Assessments

Most published and publicly available studies on the life-cycle GHG emissions data for Canadian oil sands identify two main factors contributing to the increase in emissions intensity relative to other reference crudes:

1. oil sands are heavier and more viscous than lighter crude oil types on average, and thus require more energy- and resource-intensive activities to extract;

2. oil sands are compositionally deficient in hydrogen, and have a higher carbon, sulfur, and heavy metal content than lighter crude oil types on average, and thus require more processing to yield consumable fuels by U.S. standards.

While most studies agree that Canadian oil sands crudes are on average "somewhat" more GHG-intensive than the crudes they may displace in the U.S. refineries, the range of the reported increase varies among assessments. Key design and input assumptions can significantly influence results. These factors include, but are not limited to, the following:

- **Metrics.** Comparing results from various studies is complicated by each study's choice of functional units. While GHG emissions have been normalized by most studies and reported as CO_2-equivalents, the units they are expressed "over" vary greatly. Some evaluate GHG emissions on the basis of a particular final fuel product (e.g., gasoline, diesel, or jet fuel). Others evaluate emissions by an averaged barrel of refined product. Some studies report emissions per unit of volume (e.g., millions of barrels [mbl]), and others by unit of energy produced (e.g., British Thermal Units [Btus] or megajoules [MJ]). For example, NETL 2008, Jacobs 2009, and TIEX 2009 use functional units for energy produced across the final products—MMBtus or MJs for gasoline, diesel, and/or jet fuel. IHS CERA 2010 expresses GHG emissions "per barrel of refined product produced"; while others, like Charpentier 2009 (not included in the reported findings), by "kilometers driven," among others. The choice affects how the results are presented and makes it challenging to compare across studies if the data or conversion values are not fully published or transparent.
- **Extraction Process.** GHG emissions vary by the type of extraction process used to recover bitumen. Due to the high energy demands of steam production, in-situ methods are generally assumed to be more GHG-intensive than mining operations. However, not all studies assess the difference to be the same. IHS CERA 2010 estimates the increase of WTW GHG emissions from in-situ extraction to be, on average, 7% greater than mining. NRDC 2010 estimates 9%. Specific estimates in Jacobs 2009 show a 4% increase (for SAGD dilbit over mining dilbit) and in NRCan 2008 an increase of 9% (for SAGD SCO over mining SCO).
- **In-Situ Steam-to-Oil (SOR) Ratio.** The amount of steam injected into a reservoir during in-situ processes to extract a unit volume of bitumen varies across reservoirs and across extraction facilities. The resulting energy consumption and GHG emissions estimates vary accordingly. Thus, the figure used in LCAs to express this ratio may significantly impact GHG estimates. NRCan 2008 reports SOR values from 2.5 to 5.0 across SAGD operations in Canadian oil sands. NRDC 2010 reports a range from 1.94 to 7.26. IHS CERA cites an industry average of 3. Charpentier 2009 demonstrates that GHG emissions at the production phase are very sensitive to SOR, estimating that every 0.5 increase in the ratio corresponds to an increase of 10 $kgCO_2e$ GHG emissions per barrel of bitumen produced.
- **Upgrading Process.** Bitumen needs pre-processing in order to lower its viscosity and remove impurities before it is fit for conventional refineries. This pre-processing is called "upgrading," the key components of which include (1) removal of water, sand, physical waste, and lighter products; (2) catalytic purification (i.e., the process of removing excess sulfur, oxygen, nitrogen, and

metals); and (3) hydrogenation through either carbon rejection or catalytic hydrocracking (i.e., the process of removing or breaking down the heaviest fraction of the oil residuum by either vacuum distillation and precipitation or by adding hydrogen in a "hydrocracking process that breaks long-chain hydrocarbons into shorter, more useful ones). The residuum can be further refined in a "coking" process to produce gasoline, distillate, and petroleum coke. The resulting product is synthetic crude oil (SCO) and numerous co-products, including water, sand, waste, sulfur, oxygen, nitrogen, distillate, and petroleum coke, among others. Some of the co-products from the upgrading process contain carbon and other potential GHG emission sources. Thus, a consistent and comprehensive accounting of the GHG emission from all co-products would be necessary for a full life-cycle assessment of oil sands crude—or any hydrocarbon—production.

- **Treatment of Petroleum Coke.** Petroleum coke (a source of excess carbon) is a co-product of bitumen production at both the upgrader and the refinery. Roughly 5%-10% of a barrel of crude ends up as coke; and the heavier the crude, the greater the percentage of coke. Bitumen refining can produce about 50% more coke than the average conventional crude. The treatment of coke is a primary driver behind the results of any WTW GHG oil sands assessment. If coke is combusted (i.e., for process heat, electricity, or hydrogen production *at the upgrader* in lieu of natural gas combustion), WTW GHG emissions may increase anywhere from 14% (TIAX 2009) to 50% (McCulloch 2006) over lighter crudes. If it is stored, sold, and/or combusted elsewhere, its potential emissions may not be factored into the LCA. The main concern for modeling is ensuring that coke produced at the upgrader (for SCO) is treated consistently with coke produced at the refinery (for dilbit or other imported crudes). Based on the studies analyzed in this report, petroleum coke at the upgrader is either (1) consumed (for process heat, electricity, or hydrogen production); (2) stored; or (3) sold as a fuel for combustion. In contrast, the studies assume that petroleum coke produced at the refinery that is not consumed by the refinery itself is either (1) used to back out coal combustion for electricity generation; or (2) allocated outside of the LCA.[17] These inconsistent methodologies make comparisons problematic. Coke produced at U.S. refineries has a low domestic demand, and is therefore often shipped to overseas markets for use as a replacement fuel for coal combustion or steel production (most studies include neither the overseas transportation nor the combustion emissions of coke in WTW GHG emissions assessments).
- **Cogeneration.** Cogeneration facilities use both steam and electricity generated from the steam to achieve higher energy efficiencies. In-situ extraction facilities often have steam requirements much greater than electricity requirements, thus leaving excess capacity for electricity generation that can be exported back into the grid for use elsewhere. Offset credits given to exported electricity in LCAs can have a substantial impact on WTW GHG emissions. Cogeneration

[17] Jacobs 2009 assumed that all coke is stockpiled, noting that "the practice of storing coke is typical" and that "the transport costs of marketing the material from Alberta exceed its value" (p. 4-10). In contrast, TIAX 2009 examines three scenarios where petroleum coke at upgraders is either used as a fuel, sold as a product, or buried. In comments to TIAX's report, Suncor Energy noted that 34% of the coke generated by upgrading bitumen is consumed in the production of SCO and that the rest is sold or stockpiled (p. G-3).

assumptions vary across the studies of Canadian oil sands crudes in two ways: (1) whether cogeneration credits are included, and (2) if so, what source of electricity is offset (e.g., coal-fired generation, oil, or natural gas). Some estimates show that applying credits from oil sands facilities to offset coal-fired electricity generation could reduce WTW GHG emission to within the range of conventional crudes. Many studies currently do not consider offset credits because the practice is not in widespread use among producers.

- **Upgrading and Refinery Emissions.** Because SCO delivered to a refinery has already been processed at the upgrader, the energy consumption at the refinery—and therefore the GHG emissions at the refinery—may be lower than the refinery emissions of dilbit or other crudes. Accounting for the reduced emissions from SCO has a modest effect on WTW GHG emissions, as refinery emissions are commonly around 5%-15% of the total. Many studies do not mention this accounting, and it is unclear if the reductions for SCO at the refinery are incorporated into many of the LCAs.
- **Diluents.** Because the viscosity of raw bitumen is too high to be transported via pipeline, diluting bitumen with lighter hydrocarbons to assist in its transport has become a common industry practice. Accounting for the effects of diluting bitumen is an important component in emission estimates, because producing and refining the diluents into finished products may result in a lower WTW GHG emissions estimate *per barrel* of dilbit in comparison to a barrel of raw bitumen. LCAs that report emissions for dilbit on a per barrel of refined product basis (e.g., IHS CERA 2010) are thus reporting the emissions from a combination of both oil sands bitumen and the supplemental hydrocarbons. Additionally, diluting raw bitumen with light hydrocarbons creates a crude product that is more difficult and energy-intensive to refine than other crude oils, thus producing less premium refined product per barrel after the refinery stage.[18] The extent to which this difference in yield is accounted for across the various studies is unclear. The IHS CERA 2010 estimates for crude production of SAGD dilbit do not show an adjustment for the difference. TIAX 2009 and Jacobs 2009 both show slightly higher refinery emissions for dilbit compared to other crudes, but the reasons for the increase are not specified.
- **Upstream Production Fuels.** Some studies include the GHG emissions associated with the upstream production of purchased electricity that is imported to provide process heat and to power machinery throughout crude production. The upstream GHG emissions for natural gas fuel and electricity generation used in the production of oil sands can be significant. Jacobs 2009 demonstrates that the GHG emissions associated with the upstream fuel cycle account for roughly 4%-5% of the total WTW GHG emissions for average Canadian oil sands. IHS CERA 2010 indicates that although its study excludes upstream fuel and

[18] As described in ICF 2011, diluting raw bitumen with light hydrocarbons creates what is referred to as a "dumbbell" blend, since it contains high fractions of both the heavy residuum and the light ends, with relatively low fractions of hydrocarbons in the middle that can be easily refined into premium fuel products. As a result, producing one barrel of premium fuel products (i.e., gasoline, diesel, and jet fuel) requires more dilbit input and produces more light ends and petroleum coke than refining one barrel of premium fuel products from other crudes and SCO. This results in additional energy use and GHG emissions from refining the dilbit, and producing, distributing, and combusting the light- and heavy-end co-products.

electricity GHG emissions, the inclusion of them would add 3% to WTW GHG emissions per barrel of refined product.

- **Flared, Vented, and Fugitive Emissions.** Emissions associated with flaring and venting can be a significant source of GHG emissions. The TIAX 2009 study indicates that including venting and flaring emissions associated with oil sands production (particularly for mining extraction techniques) may contribute up to 4% of total WTW GHG emissions. Further, methane emissions from fugitive leaks throughout the oil sands production process can potentially contribute up to 1% of GHG emissions.[19] Methane emissions from oil sands mining and tailings ponds may have an even larger impact, contributing from 0% to 9% of total GHG emissions.[20] TIAX 2009, McCulloch 2006, and NRCan 2008 state that they include emissions from these sources. IHS CERA 2010 excludes emissions from methane released from tailings ponds but recognizes there is considerable uncertainty and variance in quantifying these emissions. Other studies do not specify.
- **Infrastructure/Construction Emissions.** None of the existing studies include the GHG impacts associated with capital equipment and the construction of facilities, machinery, and infrastructure needed to produce oil sands. According to Bergerson and Keith 2006,[21] the relative percentage increase to WTW GHG emissions from incorporating capital equipment can be between 9% and 11%. Charpentier 2009 discusses the need to more fully investigate and include these potentially significant supply chain infrastructure GHG emissions in future oil sands life-cycle studies.
- **Local and Indirect Land-Use Change Emissions.** Emissions associated with changes in biological carbon stocks from the removal of vegetation, trees, and soil during oil sands mining operations may be significant, albeit temporary in some cases, and highly dependent upon the reclamation activities employed after use. Yeh 2010 estimates that surface mining of oil sands results in a 0.9%-2.5% increase in the WTW emissions versus the baseline (2005 U.S. average). The range was dependent on the type of lands displaced, with the removal of peatland having the largest impact and certain in-situ facilities having the least impact. None of the life-cycle studies reviewed by DOS/ICF, however, include land-use change GHG emissions in the WTW life-cycle assessment.[22] Some recent studies have begun to assess the effects.[23]

[19] Environment Canada, *National Inventory Report: 1990-2008 Greenhouse Gas Sources and Sinks in Canada*, 2010.

[20] Yeh, S., et al., "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," *Environ. Sci. Technol.*, 2010, 44 (22), pp. 8766–8772.

[21] Bergerson, J. & Keith, D., *Life Cycle Assessment of Oil Sands Technologies*, Paper No. 11 of the Alberta Energy Futures Project, University of Calgary, 2006; J. Bergerson, *The Impact of LCFS on Oil Sands Development: Hybrid LCA Methods, Presentation at the InLCA/LCM Conference*, October 2, 2007, University of Calgary.

[22] For a more detailed description of how land-use changes can be modeled into LCAs, see CRS Report R40460, *Calculation of Lifecycle Greenhouse Gas Emissions for the Renewable Fuel Standard (RFS)*, by Brent D. Yacobucci and Kelsi Bracmort.

[23] See, for example, Rooney, R., et al., *Oil Sands Mining and Reclamation Cause Massive Loss of Peatland and Stored Carbon*, PNAS, at http://www.pnas.org/cgi/doi/10.1073/pnas.1117693108.

Life-Cycle Assessments of Canadian Oil Sands Versus Other Reference Crudes

To compare the life-cycle GHG emissions intensities from Canadian oil sands crudes against those of other crude oils imported into the United States, many of the published studies conduct reference assessments of other global resources.

Findings

Figure 3 presents the results of one of the more comprehensive studies (NETL 2009), which compares Well-to-Wheel GHG emissions of reformulated gasoline across various crude oil feedstocks (a review of the NETL 2009 input assumptions is included in the figure's "Notes" section). The NETL findings show the following:

- Well-to-Wheel GHG emissions from gasoline produced from a weighted average of Canadian oil sands crudes imported to the United States are approximately 17% higher than those from gasoline derived from the weighted average of transportation fuels sold or distributed in the United States in the reference year 2005. This corresponds to an increase in Well-to-Tank (i.e., "production") GHG emissions of 80% over the weighted average of transportation fuels sold or distributed in the United States in the reference year 2005 (18 gCO_2e/MJ).
- Compared to a few selected imports, Well-to-Wheel GHG emissions from gasoline produced from a weighted average of Canadian oil sands crudes are 19%, 12%, and 18% higher than the life-cycle emissions from Middle Eastern Sour, Mexican Maya, and Venezuelan Conventional crudes, respectively.[24] This corresponds to an increase in Well-to-Tank (i.e., "production") GHG emissions of 102%, 53%, and 92% higher than the production emissions from Middle Eastern Sour, Mexican Maya, and Venezuelan Conventional crudes, respectively.

Individual estimates of WTW GHG emissions from Canadian oil sands crudes from the primary studies listed in **Table 1** range from 9% to 19% more GHG-intensive than Middle Eastern Sour, 5% to 13% more GHG-intensive than Mexican Maya, and 2% to 18% more GHG-intensive than various Venezuelan crudes (including both Venezuelan Conventional and Bachaquero).

Design Factors and Input Assumptions for Reference Crudes Assessments

Similar to LCAs conducted on Canadian oil sands crudes, assessments of other global crude resources confront many variables and uncertainties in available data. Likewise, these assessments are bounded by specific design factors and input assumptions that can affect the quality of the results. Conditions that may impact the results include the following:

- **Choice of Reference Crudes Studied.** Crude oil resources around the world vary significantly in regard to resource quality and production methods. Thus, GHG emissions intensities may also vary significantly. The results of

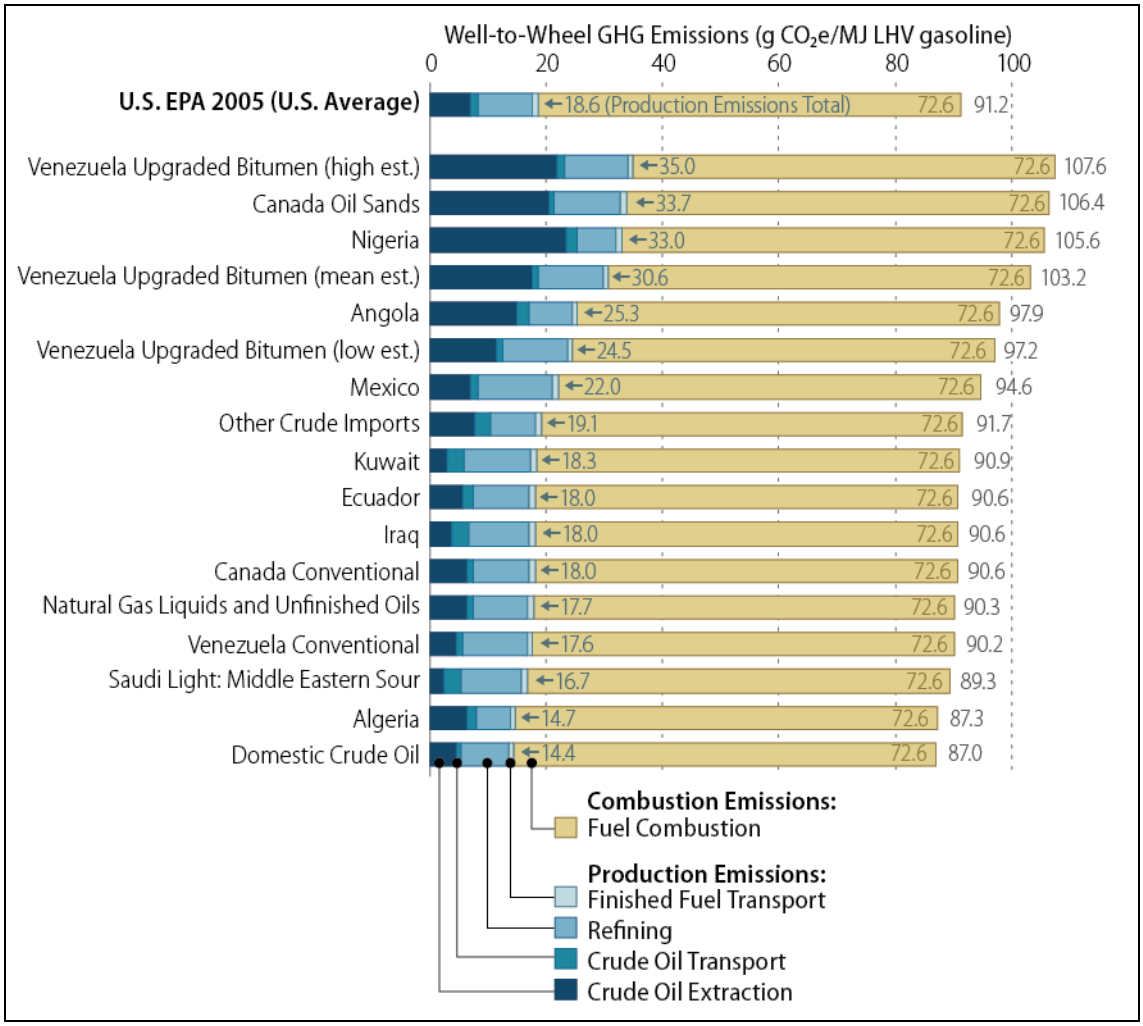
[24] NETL 2009 assumes the production of these specific reference crudes could be affected most by an increase in Canadian oil sands production. See next section "Design Factors and Input Assumptions for Reference Crudes Assessments."

comparisons between Canadian oil sands and other global crudes may depend on which crudes are used as a reference and/or which crudes are evaluated to determine a baseline. Some studies suggest that GHG emissions intensities of Canadian oil sands crudes should be measured against a global average in order to assess the full environmental impacts of the resource. Others believe they should be measured against an average of all crudes consumed in a given marketplace (e.g., a particular country or region, like the United States or the European Union). Still others argue that Canadian oil sands crudes should be measured against a representative basket of crudes they may displace in production (e.g., crudes potentially displaced by Canadian oil sands crudes at U.S. PADD III refineries; or, more specifically, only "heavy" crudes potentially displaced at U.S. PADD III refineries).[25]

- **Sensitivity to Water-Oil and Gas-Oil Ratios.** Due to the complex nature of crude oil production systems and resource reservoirs, studies often use ratios to describe the fraction of the flow from a well that is oil, water, and gas. The use of ratios simplifies the relationship between energy use and GHG emissions and may fail to accurately report the variability across differing resources. Further, assumptions regarding venting or flaring of associated gas, and fugitive emissions from produced water, may further impact GHG emissions intensities.
- **Transportation Emissions.** Assumptions regarding how LCAs account for the contribution of transportation may impact WTW GHG emissions estimates to a small degree. These include the distance and mode of transportation from oil field to export terminal, and from producer to refiner, as well as the final transportation emissions of all co-products.
- **Uncertainty Analysis.** Accurately measuring GHG emissions intensities is highly uncertain. Few of the studies listed in **Table 1** fully consider associated uncertainty, and none of them rigorously treat underlying uncertainties in data inputs and models. Most calculate averages from a wide range of values and develop point estimates without providing statistical bounds. These bounds may prove to be important if their ranges are shown to overlap with other results.
- **Data Transparency.** The quality of the data and the transparency in presentation vary considerably by study. Most studies do not provide complete transparency in their methodologies, assumptions, or data sources. This is partially a function of the difficulty in accessing necessary data elements from the field. Data on oil sands are more robust than some global resources and less robust than others. Lack of transparency impedes the ability to make meaningful comparisons of the results for oil sands-derived crudes and reference crudes.

[25] Each of the studies listed in **Table 1** makes different assumptions regarding reference crudes and baselines. NETL 2009 assumes that resources from Venezuela or Mexico may likely be the first displaced by Canadian oil sands crudes in U.S. refineries. However, to the extent that a crude like Saudi Light (i.e., Middle Eastern Sour) is the world's balancing crude, NETL also suggests that it may ultimately be the resource backed out of the global market by increased Canadian oil sands production. Many factors—from economics, to geopolitics, to trade issues—would influence the balance of global petroleum production. An analysis of how incremental production of Canadian crudes would affect the production levels of other global crudes, and which of those crudes would be backed out of U.S. refineries and/or global production, is beyond the scope of this report. For more detail on global oil markets, see CRS Report R41765, *U.S. Oil Imports: Context and Considerations*, by Neelesh Nerurkar.

Figure 3. Well-to-Wheel GHG Emissions Estimates for Global Crude Resources



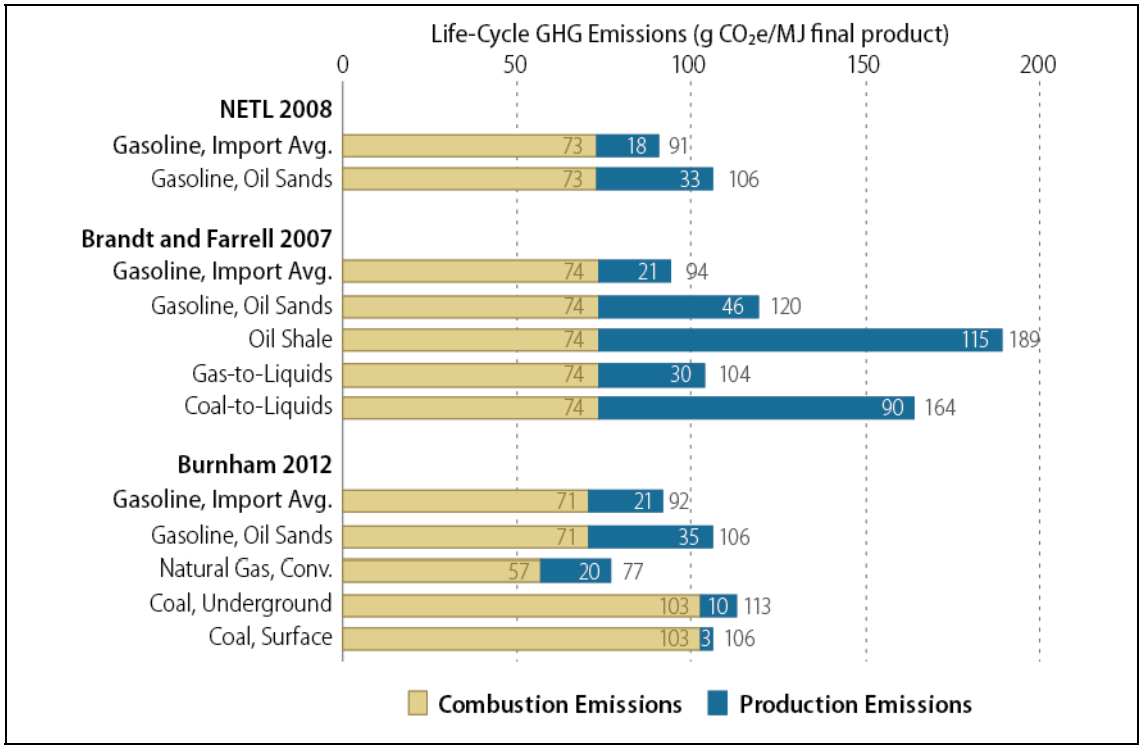
Source: CRS, from NETL, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions*, National Energy Technology Laboratory, March 27, 2009.

Notes: U.S. EPA 2005 (U.S. Average) assesses "the average life cycle GHG profile for transportation fuels sold or distributed in the United States in 2005 [and] is determined based on the weighted average of fuels produced in the U.S. plus fuels imported into the U.S. minus fuels produced in the U.S. but exported to other countries for use" (NETL 2008, p. ES-5). This baseline includes Canadian oil sands, but does not include emissions from some of the most carbon-intensive imported crude oils (e.g., Venezuelan Heavy) due to modeling uncertainties (NETL 2008, p. ES-7; NETL 2009, p. ES-2). NETL values converted from $kgCO_2e$/MMBtu using conversion factors of 1,055 MJ/MMBtu and 1,000 g/kg. NETL input assumptions are as follows: (1) assumes a weighted average of Canadian oil sands extraction at 43% raw bitumen (not accounting for blending with diluents to form dilbit) from CSS in-situ production and 57% SCO from mining production in the years 2005 and 2006; (2) allocates refinery emissions from co-products other than the gasoline, diesel, and jet fuel to the co-products themselves, including petroleum coke, and thus outside the boundaries of the LCA (unless combusted at refinery); (3) uses linear relationships to relate GHG emissions from refining operations based on API gravity and sulfur content, thus failing to fully account for the various produced residuum ranges of bitumen blends and SCO; (4) does not fully evaluate the impact of pre-refining SCO at the upgrader prior to the refinery; (5) does not account for the transportation emissions of co-products; and (6) bounds the GHG emissions estimates for Venezuela's ultra-heavy oil/bitumen using uncertainty analysis due to the limited availability of public data. Further, as noted in **Table 2**, NETL 2009 study assumptions do not state SOR, do not include upstream fuel production, do not include infrastructure or land-use changes, and do not specify cogeneration, but do include emissions from venting, flaring, and fugitives.

Life-Cycle Assessments of Canadian Oil Sands Versus Other Fuel Resources

Figure 4 offers a comparison of the life-cycle GHG emissions intensities of petroleum products from Canadian oil sands crudes with estimates from other unconventional petroleum products, natural gas, and coal. These data are drawn from several different studies employing many different design features and input assumptions, not the least of which are different methods of combusting the final fuel products. Further, it should be noted that different and non-substitutable end uses for the fuel products (e.g., the different end uses for coal and petroleum combustion) make a full comparison of their emissions impacts problematic. The figure presents an average value for each fuel; the original source materials provide a full description of each study's design characteristics as well as a presentation of each estimate's uncertainty analysis.

Figure 4. Life-Cycle GHG Emissions Estimates for Selected Fuel Resources



Source: CRS, from NETL, *Development of Baseline Data and Assessment of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, National Energy Technology Laboratory, November 26, 2008; Brandt, A.R. and A.E. Farrell, "Scraping the Bottom of the Barrel: Greenhouse Gas Emission Consequences of a Transition to Low-quality and Synthetic Petroleum Resources," *Climatic Change*, Vol. 84, 2007, pp. 241-263; and Burnham, A., et al., "Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum," *Environmental Science and Technology*, Vol. 46, 2012, pp. 619–627.

Notes: NETL values converted from kgCO_2e/MMBtu using conversion factors of 1,055 MJ/MMBtu and 1,000 g/kg; Brandt values converted from gCe/MJ using conversion factor of 3.667 Ce/CO_2e.

U.S. Carbon Footprint for the Keystone XL Pipeline

In response to comments on the draft Environmental Impact Statement (EIS) for the Keystone XL pipeline project and as a "matter of policy," the DOS/ICF study provides estimates for the incremental GHG emissions resulting in the production of Canadian oil sands crudes likely to be transported by the Keystone XL pipeline project (i.e., the U.S. GHG emissions footprint).[26]

Incremental GHG emissions are determined by the following:

1. the presumed throughput of the pipeline,
2. the mix of oil sands crude types imported through the pipeline, and
3. the GHG emission intensity of the crudes in the pipeline compared to the crudes they displace.

For illustrative purposes, the Final EIS uses the emissions assessment data from Jacobs 2009, TIAX 2009, and NETL 2009 to develop weighted averages of Canadian crudes and other reference crudes for the purposes of the carbon footprint analysis. DOS/ICF assumes the near-term initial throughput of the proposed Keystone XL pipeline to be 700,000 barrels of crude per day, with a potential capacity of 830,000 barrels per day. Using the Jacobs 2009 and TIAX 2009 assessments, DOS/ICF estimates that the throughput for the pipeline would be 50% SCO and 50% dilbit, with all dilbit produced using in-situ methods and 12% of SCO produced using in-situ methods, yielding a final mix of 50% in-situ produced dilbit, 44% mining produced SCO, and 6% in-situ produced SCO. Using the NETL 2009 assessment, DOS/ICF calculates a mix of 43% crude bitumen and 57% SCO. Incremental GHG emissions for Canadian crudes are computed against four different reference crudes: Middle Eastern Sour (with the assumption that as the world's balancing crude, it may ultimately be the crude that is backed out of the world market by increased production of Canadian crudes), Mexican Maya and Venezuelan Bachaquero (with the assumption that as the heavy crudes currently in the input mix at U.S. refineries, they are likely to be the first displaced by an increased production of Canadian crudes), and a reference crude based on the average mix imported and refined in the United States in 2005.

The analysis found that the potential range of incremental GHG emissions contributed by the pipeline would be 3-17 $MMTCO_2e$ annually at the near-term initial throughput and 4-21 $MMTCO_2e$ annually at the potential throughput. As the United States reported a total domestic GHG inventory of 6,865.5 $MMTCO_2e$ in 2010,[27] the incremental pipeline emissions would represent an increase of 0.06%-0.3% in total annual GHG emissions for the United States. This overall range is equivalent to annual GHG emissions from the combustion of fuels in approximately 588,000 to 4,061,000 passenger vehicles, or the CO_2 emissions from combusting fuels used to provide the energy consumed by approximately 255,000 to 1,796,000 homes for one year.[28]

[26] DOS, Final EIS, 3.14.52-56.

[27] See 2012 Draft U.S. Greenhouse Gas Inventory Report, Table-ES-2, at http://epa.gov/climatechange/emissions/downloads12/Executive%20Summary.pdf.

[28] Final EIS, 3.14-55.

Further Considerations

Life-cycle assessment has emerged as an influential methodology for collecting, analyzing, and comparing the GHG emissions and climate change implications of various hydrocarbon resources. However, because of the complex life cycle of hydrocarbon fuels and the large number of analytical design features that are needed to model their emissions, LCAs retain many variables and uncertainties. These uncertainties often make comparing results across resources or production methods problematic. Hence, the usefulness of LCA as an analytical tool for policymakers may lie less in its capacity to generate comparative rankings, or "scores," between one source and another, and more in its ability to highlight "areas of concern," or "hot spots," in the production of a given hydrocarbon fuel. In this way, LCA can serve to direct policymakers' attention to those areas in resource development that present the greatest challenges to GHG emissions control, and hence, the biggest potential benefits if adequately managed.

Table 3 summarizes the GHG emissions impacts of the various stages of Canadian oil sands production and presents examples of mitigation strategies that have been offered by industry, academia, and other stakeholders.

Table 3. Potential GHG Mitigation Activities in Canadian Oil Sands Production

Magnitude of Source's GHG Impact	Source of GHG	Mitigation Activity
Significant	Upstream Fuels for Production	Energy-efficiency measures.
		Use of natural gas or bio-based fuels such as biodiesel or bioethanol in mining and trucking fleets and equipment.
	Extraction	In-situ extraction improvements such as improved well configuration and placement, low-pressure SAGD, flue gas reservoir re-pressurization, new artificial lift pumping technologies, use of electric submersible pumps, and overall improvements in energy efficiency that can reduce the steam-to-oil ratios (SOR) of in-situ production processes.
		Steam solvent processes, which use solvents to reduce the steam required for bitumen extraction. These include solvent-assisted processes (SAP), expanding solvent steam-assisted gravity drainage (ES-SAGD), and liquid addition to steam for enhanced recovery (LASER).
		Electrothermal extraction, where electrodes are used to heat the bitumen in the reservoir.
		Use of lower-temperature water to separate bitumen from sand during extraction to reduce the energy required.
		In-situ combustion, where the heavy portion of petroleum is combusted underground.

Magnitude of Source's GHG Impact	Source of GHG	Mitigation Activity
	Upgrading and Refining	Expanded use of cogeneration to produce electricity and steam during the upgrading stages of oil sands production, particularly for in-situ production.
		Bio-upgrading technology in development that includes the use of microbes to remove sulfur compounds and impurities.
		Use of co-products (e.g., petroleum coke) as replacement fuels for coal-fired power generation.
	Storage	Carbon capture and storage (CCS) technologies to store CO_2 produced from point sources.
	Vented Emissions	Vapor recovery units where possible, flares otherwise.
Moderate	Land-Use Changes	Reclamation.
	Capital Equipment and Infrastructure	Energy-efficiency measures.
Small	Transportation	Energy-efficiency measures.
	Fugitive Emissions	Leak detection and repair.

Source: CRS, from studies outlined in **Table 1**.

Notes: Significant = greater than approximately 3% change in WTW emissions. Moderate = approximately 1%–3% change in WTW emissions. Small = less than approximately 1% change in WTW emissions.

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