Oil Sands, Greenhouse Gases, and US Oil Supply

Getting the Numbers Right—2012 Update

IHS

CERA

About this report

Purpose. This IHS CERA report compares life-cycle GHG emissions among sources of US oil supply including the Canadian oil sands. It is an update to our September 2010 IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right*. This updated analysis includes the most recent GHG emissions estimates and clarifies our meta-analysis methodology.

Context. This is part of a series of reports from the IHS CERA Canadian Oil Sands Energy Dialogue. The dialogue convenes stakeholders in the oil sands to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Stakeholders include representatives from governments, regulators, oil companies, shipping companies, and nongovernmental organizations.

Past Oil Sands Dialogue reports can be downloaded from the Oil Sands Dialogue Research Archive at www.ihs.com/oilsandsdialogue.

Methodology. This report includes multistakeholder input from a focus group meeting held in Washington, DC, on 15 November 2011 and participant feedback on a draft version of the report. IHS CERA also conducted its own extensive research and analysis, both independently and in consultation with stakeholders. IHS CERA has full editorial control over this report and is solely responsible for the report's contents (see the end of the report for a list of participants and the IHS CERA team).

Structure. This report has four sections and an appendix that provides a more detailed description of our methodology and data supporting our analysis.

- Part 1: Introduction

- Part 2: The Basics: Comparing GHG Emissions from Crude Oil

- Part 3: The Results: GHG Emissions for US Oil Supply

- Part 4: Look to the Future

- Appendix: Detailed Methodology, Original Source Data, Constants, and Calculations (a separate document)

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OIL SANDS, GREENHOUSE GASES, AND US OIL SUPPLY: GETTING THE NUMBERS RIGHT—2012 UPDATE

SUMMARY OF KEY INSIGHTS

- **In comparing life-cycle greenhouse gas (GHG) emissions estimates for crude oils, a common error is directly comparing results across a range of studies without acknowledging differing assumptions and methods.** This IHS CERA meta-analysis creates a common basis that is more appropriate for cross-study comparisons and for creating a best estimate of emissions from a group of studies.

- **Limited data availability and quality make GHG emissions estimates for crude oil uncertain. Consequently, life-cycle analysis is a challenging basis for policy, and transparent jurisdictions, such as Canada, can be penalized.** Across our meta-analysis, the production emissions estimates for a single crude varied by an average of 30%. Data quality is a significant driver of the range. For policies designed to differentiate crudes by their carbon intensity, if estimates rely on data of unequal quality, they could simply shift demand to countries or sectors with mischaracterized levels of GHG emissions instead of actually reducing emissions.

- **When the boundary for measuring GHG emissions is placed around crude production and processing facilities, for fuels produced solely from oil sands the average well-to-wheels life-cycle GHG emissions are 11% higher than for the average crude refined in the United States (results range from 4% to 18% higher).** Well-to-wheels emissions include those produced during crude oil extraction, processing, distribution, and combustion in an engine. Although oil sands–derived crudes are more carbon intensive than the average oil refined in the United States, they are within the range of some other crude oils produced, imported, or refined in the United States, including crudes from Venezuela, Nigeria, Iraq, and California heavy oil production.

- **When GHG emissions beyond the facility site are accounted for, transportation fuels produced solely from oil sands result in average well-to-wheels GHG emissions that are 14% higher than the average crude refined in the United States (results range from 5% to 23% higher).** Emissions beyond the facility site include those from producing natural gas used at oil production facilities and from electricity generated off site. Although not part of the typical method a few years ago, these emissions are accounted for in more recent studies, and we included them in this update. For many crude oils these indirect emissions are not material, but for some crudes (including oil sands) they are more consequential. However, as the boundary for measuring GHG emissions grows wider, the uncertainty in the estimate also increases.

—November 2012

OIL SANDS, GREENHOUSE GASES, AND US OIL SUPPLY: GETTING THE NUMBERS RIGHT—2012 UPDATE

PART 1: INTRODUCTION

How much greenhouse gas (GHG) is emitted from the use of various sources of crude oil? This is not simply an academic question, but one that has implications for policy decisions and energy economics. GHG emissions levels from specific crude sources factor into energy policy in a number of jurisdictions, with the potential to affect the market for higher-carbon crudes, such as the crudes from oil sands.

Low-carbon fuel standards (LCFS) use life-cycle GHG emissions as a basis for regulation, requiring a reduction in GHG emissions from the total life cycle of a fuel. For crude oil this includes all emissions—from producing through refining and ultimately consuming the fuel. In British Columbia, California, and the European Union, LCFS initiatives are at various stages of deployment. Some of these policies specifically single out oil sands from other types of crude oil.

GHG emissions from crude oil have also been a concern for new oil sands pipeline applications. Within some submissions, the GHG emissions from oil sands (when compared with the crude oils they would replace) have been a point of consideration.

To help make sense of the mind-boggling and often conflicting numbers that are published to describe the GHG emissions from oil sands and other crude oils, this report updates our GHG emissions meta-analysis, first published in the September 2010 IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right.* The current report includes our most recent GHG emissions estimates and clarifies the methodology used for our analysis.

This report has four parts plus appendixes:

- Part 1: Introduction

- Part 2: The Basics: Comparing GHG Emissions from Crude Oils

- Part 3: The Results: GHG Emissions for US Oil Supply

- Part 4: Look to the Future

- Appendixes: Detailed Methodology, Original Source Data, Constants, and Calculations (a separate document)

Throughout this report, we refer to a number of unique oil sands extraction methods and marketable products. See the box "Canadian oil sands primer" for definitions.

Canadian oil sands primer

The immensity of the oil sands is their signature feature. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 170 billion barrels, making oil sands the world's third largest proven oil reserve (after Saudi Arabia and Venezuela). The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands is bitumen, an extra-heavy oil with high viscosity. Given their black and sticky appearance, the oil sands are also referred to as "tar sands." Tar, however, is a man-made substance derived from petroleum or coal.

Raw bitumen is semisolid at ambient temperature and cannot be transported. It must first be diluted with light oil or converted into a synthetic light crude oil. Several crude oil–like products are produced from bitumen, and their properties differ in some respects from conventional crude oils.

- **Synthetic crude oil (SCO).** SCO is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. These units are called upgraders. SCO resembles light sweet crude oil with API gravity typically greater than 30 degrees. However, since SCO produces a smaller range of products compared with conventional crude oil, a typical refinery can use SCO as only a fraction of its total feedstock.*

- **Diluted bitumen (dilbit).** Dilbit is bitumen mixed with a diluent. The diluent is typically a natural gas liquid such as condensate. Dilbit is generally a mix of about 72% bitumen and the remainder condensate. This is done to make the mixed product "lighter," and the lower viscosity enables the dilbit to be transported by pipeline. Some refineries will need modifications to process large amounts of dilbit feedstock because it produces more heavy and more very light oil products compared with most crude oils.

Oil sands are unique in that they are extracted via mining, in-situ thermal, and primary processes.

- **Mining.** About 20% of currently recoverable oil sands reserves lie close enough to the surface to be mined. In a strip-mining process similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed, and the layer of oil sands is excavated using massive shovels that scoop the sand, which is then transported by truck, shovel, or pipeline to a processing facility. The original mining operations always produced SCO. However, a new mining operation is under construction that will not include an upgrader and produce SCO. Instead the bitumen will be extracted (using the paraffinic froth treatment [PFT] process) and shipped to market as dilbit. Slightly less than half of today's production is from mining, and we expect this proportion to be about 40% by 2030.

- **In-situ thermal processes.** About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. Thermal methods inject steam into the wellbore to lower the viscosity of the bitumen and allow it to flow to the surface. Such methods are used in oil fields around the world to recover oil. Thermal processes make up 40% of current oil sands production, and two commercial processes are used today:

  - **Steam-assisted gravity drainage (SAGD).** SAGD is the fastest growing method; it is projected to grow from 20% of 2011 production to almost 45% of oil sands production by 2030.

  - **Cyclic steam stimulation (CSS).** CSS was the first process used to commercially recover oil sands in situ. Currently making up 17% of total production, it is projected to account for less than 10% of total production in 2030.

- **Primary.** The remaining oil sands production is less viscous and can be extracted without steam. Primary production currently makes up 13% of oil sands production. Most primary oil is extracted using the cold heavy oil production with sand (CHOPS) method that produces formation sand along with the oil. Recently, secondary recovery techniques, such as polymer flooding (which is akin to pushing jello though the formation to produce the thick oil), are also being deployed. Primary production is projected to make up about 5% of total production in 2030.

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*Since SCO does not contain residual (heavy) oil, there is a limit to the amount of SCO that can be ultimately processed at a refinery.
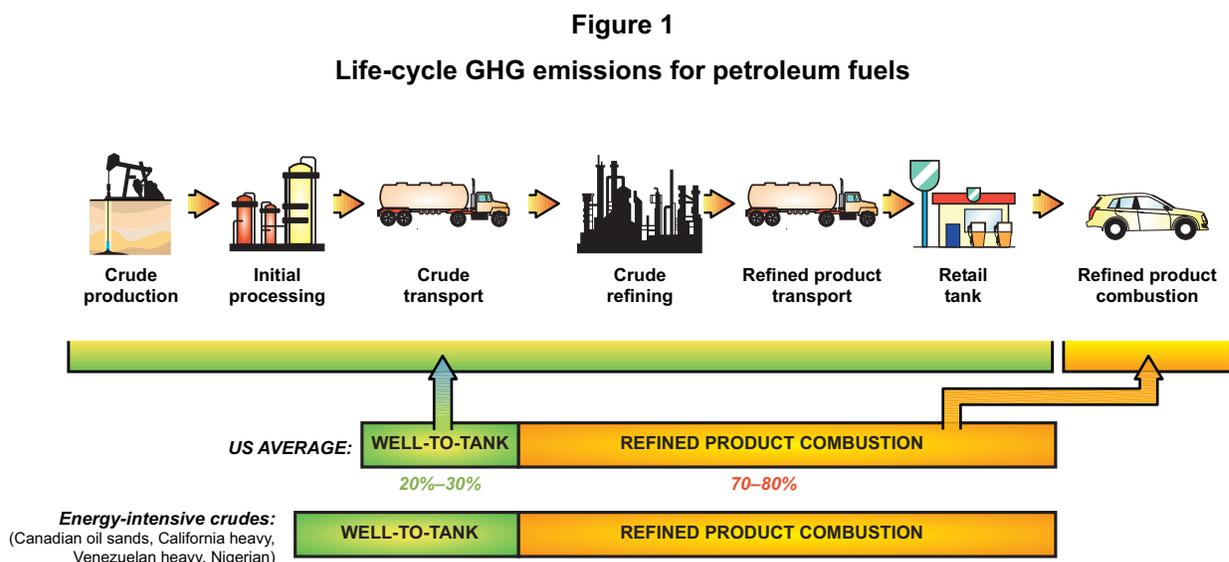
PART II: THE BASICS: COMPARING GHG EMISSIONS FROM CRUDE OILS

Evaluating and comparing the life-cycle GHG emissions of fuels is a complex process owing to the differences in the data used and in the types of inputs considered. This section provides

- "the basics" on comparing GHG emissions among crude oils, including a description of life-cycle analysis for crude oil

- an overview of key uncertainties in estimating oil GHG emissions

- and an introduction to meta-analysis—the method used in this report to analyze the GHG emissions for crude oils

LIFE-CYCLE ANALYSIS OF GHG EMISSIONS FROM CRUDE OIL

Life-cycle analysis aims to account for all of the GHG emissions associated with a product, from its production through its end use. For petroleum transportation fuels, life-cycle analysis encompasses all GHG emissions—everything from producing the crude oil, refining it, and transporting it to finally combusting the fuel in a vehicle's engine. For road transport, life-cycle emissions are often referred to as "well-to-wheels" or "well-to-tailpipe" emissions. When GHG emissions are viewed on the well-to-wheels basis, the emissions released during the combustion of fuel (such as gasoline and diesel) make up 70% to 80% of total emissions (see Figure 1). These combustion emissions are the same for all crudes. *Whether the refined product (such as gasoline or diesel) is derived from oil sands or conventional oil, the combustion emissions are equal.*

Figure 1

Life-cycle GHG emissions for petroleum fuels

| Crude production | Initial processing | Crude transport | Crude refining | Refined product transport | Retail tank | Refined product combustion |

US AVERAGE: WELL-TO-TANK — REFINED PRODUCT COMBUSTION
20%–30% — 70–80%

Energy-intensive crudes:
(Canadian oil sands, California heavy, Venezuelan heavy, Nigerian) — WELL-TO-TANK — REFINED PRODUCT COMBUSTION

Source: IHS CERA.
90513-30_3110

Since combustion emissions are uniform across all sources of crude oil, the variability in life-cycle emissions among petroleum fuels occurs in the "well-to-tank" portion of the life cycle, which makes up 20% to 30% of the total well-to-wheels emissions from petroleum fuels.

SOURCES OF DIFFERENCES AMONG LIFE-CYCLE ANALYSES

Measuring the life-cycle GHG emissions of fuels is a complex process. Across the 12 sources compared in our meta-analysis, when multiple studies estimated the carbon intensity of a single crude oil, the production emissions estimates varied by an average of 30%. This significant variability in results highlights the level of uncertainty in measuring life-cycle greenhouse gas emissions. Indeed, in many cases the uncertainty in emissions estimates is larger than the GHG emissions reductions that the policy requires—a key challenge in developing policies that are based on life-cycle analysis. Most differences among studies arise in four places, summarized below.

Data quality and availability

Data quality and availability are the most significant factors creating a wide range in GHG emissions estimates. Accurate data are often difficult to obtain for comparing GHG emissions across specific crude types. Frequently, oil and gas data are considered proprietary. Even when data can be obtained, data vintage is a second issue. The GHG intensity of a specific operation changes over time, so more current data are preferred.

IHS CERA highlighted the challenge of data availability on various environmental aspects of crude production in the October 2011 IHS CERA Special Report *Major Sources of US Oil Supply: The Challenge of Comparisons.* This report compared current and future major sources of US oil supply—US domestic production, Canada, Mexico, Saudi Arabia, Nigeria, Venezuela, Brazil, and Iraq—based on environmental data availability. Only half of the jurisdictions provided enough environmental data to make meaningful comparisons on environmental aspects of oil production—including GHG emissions from oil developments. Even if the data are available, often an information request is required to obtain the data, meaning a significant gathering and vetting exercise must be conducted. Of the countries compared, Canada's oil sands industry was at the forefront of having meaningful and accessible data to support GHG emissions estimates.

A driver of uncertainty in estimating GHG emissions for crude oil is the amount of venting and flaring during oil production. If venting and flaring are regular practices, then the crude's carbon intensity is likely relatively high. Some of the studies used in our meta-analysis relied on data from satellite imagery for estimating flaring, and data for venting were generally not available. However, for Canadian crudes, venting and flaring data are measured, audited, and available. Canada is one of the few producing nations that make these emissions data accessible.

To help illustrate the problem of data availability, consider the crude oil GHG emissions estimates for California's Low Carbon Fuel Standard. To support its policy, California's Air

Resources Board modeled the GHG emissions of a variety of domestic and foreign crudes.* Although data for domestic and Canadian crudes were generally available, the data required to estimate the GHG emissions for other crudes were sparse. Information was extracted from a number of sources, including conference presentations, papers, and magazine articles. Even then, not all required information was available, and default values were assumed for many inputs. For example, the volume of steam used in producing oil is a key indicator of GHG emissions. For Canadian oil production, steam rates were based on facility-level annual averages measured by instruments and reported to the regulator, while these data were generally unavailable for other foreign crudes.

In the end, the output of a model is only as good as the input. For policies designed to use carbon intensity to differentiate among crude oils, if estimates rely on data of unequal quality, they could simply shift demand to countries or sectors with mischaracterized levels of GHG emissions instead of actually reducing emissions.

Allocation of emissions to coproducts

Life-cycle analysis often requires attributing emissions from a process to multiple outputs of that process. Depending on how emissions are allocated to each product, the emissions for a specific product can vary substantially. Studies of well-to-wheels emissions vary greatly in their methods of allocating emissions to refined products. For instance, some studies allocate all GHG emissions to the gasoline stream (with the reasoning that all other products are simply by-products of gasoline production). Other studies allocate the emissions across all products by volume, while others divide GHG emissions based on the energy content of the products or the energy consumed in making the products.

Differing system boundaries

Deciding which steps and processes in oil production to include in the system boundary—including how far back in the supply chain to reach—is another difference among life-cycle analyses. Emissions directly attributable to production are typically included, but some studies do not include secondary or indirect emissions, such as emissions from upstream fuels (producing the natural gas or electricity off site), the impacts of land use change, or emissions from construction of the facility. Generally, as the boundary is drawn wider, the uncertainty in the estimate increases.

Differing study purpose

The purpose of a study can drive the range of GHG emissions estimates observed. Some studies aim to present a detailed "bottom-up" analysis of a specific operation and crude type and require a high level of data precision. Other studies—often those supporting policy—aim to represent the average GHG emissions for the industry or a country as a whole and consequently rely on less precise data.

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*California's Air Resources Board released draft carbon intensities for various crude oils, posted 17 September 2012: http://www.arb.ca.gov/regact/2011/lcfs2011/lcfs2011.htm, retrieved 10 October 2012. These values are not final and at the time of publication had been submitted to the California Office of Administrative Law for final approval.

For a more detailed explanation of the key drivers of difference in life-cycle analysis, please refer to the original study.*

IHS CERA META-ANALYSIS: COMPARING GHG EMISSIONS FROM CRUDE OIL

Comparing results directly across studies that use different assumptions is a common error. Such an approach distorts the difference in GHG emissions among crude oils. To compare results across sources, a meta-analysis must be conducted.

A meta-analysis is a valuable tool that allows a researcher to compare estimates across different studies and thus understand the range of possible outcomes. A meta-analysis combines the results of several independent studies and is less influenced by local findings or biases. Meta-analysis is used widely in areas of natural science, social science, and policy research. For instance, it has been used to combine results from clinical trials, from psychological studies, and from studies evaluating energy savings from technology.

To analyze the GHG emissions from crude oil, IHS CERA used a meta-analysis approach—converting the results of 12 different studies into an "apples-to-apples" basis and comparing the GHG emissions estimates across sources of crude oil. Table 1 lists the sources used within our meta-analysis.

To improve the meta-analysis quality and currency over our 2010 study, we used a new set of sources. Older studies were excluded from this update because they contained limited information about their assumptions and inputs or because they were dated and did not necessarily reflect the energy intensity of current operations or the latest methods for estimating emissions.

Because each of the 12 sources employed different assumptions in measuring GHG emissions from crude oil (for instance, different system boundaries, refinery complexity assumptions, and allocation of emissions among refinery coproducts), it is not valid to directly compare the absolute GHG emissions estimates across studies; that would be like "comparing apples to oranges."

The following is a brief overview of the steps of our meta-analysis (see Appendix 1 for step-by-step description).

Step 1: Converting studies to common units and allocations. Life-cycle studies publish their results using a variety of units. Some studies report on a per-barrel-of-crude-oil basis; others report GHG emissions on the basis of a unit of energy from refined products, such as gasoline or diesel.

Studies that report GHG emissions on the basis of refinery products allocate emissions among numerous products, such as gasoline, diesel, gas liquids, bunker fuel, and electricity. However, as the allocation methods among studies differ, it is incorrect to directly compare refined product GHG emissions among studies (see the box "Comparison of refined product GHG emissions: Jacobs and TIAX LLC").

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*See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right.*

Table 1

GHG emission sources included in IHS CERA meta analysis

1. IHS CERA (2009)	Data produced independently by IHS CERA that estimates production emissions for three crudes: Ekofisk, Kashagan, and Starfjord.
2. Environment Canada (2010)	Direct GHG emissions data for oil sands facilities from Environment Canada.
3. DOE/NETL (2008)	US Department of Energy (DOE)/National Energy Technology Laboratory (NETL), "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008. Although DOE/NETL issued a subsequent report in 2009, we used the 2008 study because it reported oil production emissions on a per-barrel-of-crude basis.
4. Jacobs (2012)	Jacobs Consultancy, "EU Pathway Life Cycle Assessment of Crude Oils In a European Context," March 2012.
5. Jacobs (2009)	Jacobs Consultancy, "Life Cycle Assessment Comparison of North American and Imported Crudes," July 2009.
6. Charpentier (2011)	Charpentier et al., "Life Cycle Greenhouse Gas Emissions of Current Oil Sands Technologies: GHOST Model Development and Illustrative Application," July 2011.
7. GHGenius (2011)	Canadian oil sands estimates from the most current version of GHGenius model—v 4.01a (2011).
8. GREET (2012)	Canadian oil sands mining SCO estimate from the most current version of GREET model (GREET1_2012 rev., released July 2012).
9. CARB-OPGEE (2012)	To support California's Low Carbon Fuel Standard, the California Air Resources Board released draft Carbon Intensities for various crude oils consumed in California (posted 17 September 2012). The GHG estimates were made using the OPGEE v1.0 model.
10. Yeh (2010)	Yeh et al., "Land Use Greenhouse Gas Emissions from Conventional Oil Production and Oil Sands," October 2010.
11. Environmental Impact Assessments (EIAs)	For oil sands mining cases, data within the Environmental Impact Assessments (EIA) provided estimates for fugitive emissions from tailings ponds and the mine face.
12. Alberta Environment (2011)	Data from Alberta Environment and Sustainable Resource Development; 2011 data submitted to the regulator to describe the fugitive emissions (tailings and mine face) for three oil sands mining sites.

Source: IHS CERA.

The first step of our meta-analysis resolves the allocation discrepancy by putting all study results on the basis of a full barrel of refined products. A basis that includes all refined products made from the crude oil (as opposed to one product such as gasoline or diesel) removes the allocation method as a source of uncertainty in comparing GHG emissions across studies.

For our analysis, we assumed a high-conversion refinery that produces only three liquid products (gasoline, diesel, and natural gas liquids) and no heavy fuel oil. The refinery also creates petroleum coke as a by-product of refining. Petroleum coke can be used for a variety of applications, but the most typical use is in power generation. Because the coke is simply displacing coal that would otherwise have been burned in power generation, the net emissions from producing the petroleum coke are negligible. In life-cycle analysis, this approach is commonly used and referred to as displacement (see Figure 2, and see Appendix 1, Part B for a more detailed description of the IHS CERA per-barrel-of-refined product basis).

Step 2: Putting the results into a comparable framework. Once common units are established, the next step is putting the results of each study into a comparable framework. Not all studies cover the full spectrum of well-to-wheels GHG emissions; therefore the results of each study must be broken out into their respective life-cycle components.

A common inconsistency among studies is that system boundaries differ. All studies must establish a system boundary for measuring the GHG emissions. Some studies draw the system boundary tightly around the production facilities and the refinery and do not include emissions produced further upstream, such as emissions from producing upstream fuels (such as natural gas consumed at the facility and emissions from producing imported electricity) or GHG emissions resulting from land use change.

Comparison of refined product GHG emissions: Jacobs and TIAX LLC

Figure 3 illustrates why comparing GHG emissions among studies with differing assumptions leads to misleading conclusions. This figure compares two estimates of the well-to-tank GHG emissions for producing gasoline and diesel from the same crude oil (mining oil sands to produce SCO). Study 1 (Jacobs) allocates emissions about equally between gasoline and diesel, and Study 2 (TIAX LLC) allocates emissions mostly to the gasoline stream. Comparing the diesel GHG intensities between these two studies, one could (incorrectly) conclude that the crude oil in Study 2 is less GHG-intense than that of Study 1. However, the crude oils are the same, and the difference stems from differences between the studies, including different assumptions on production and refinery complexities and models, as well as each study's unique method of allocating emissions to refinery products.

Since the release of our original IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right* (September 2010) we have received numerous requests to provide our values on a gasoline or a diesel basis—in large part because other studies report their results in this way. In response to these requests, we have provided our updated results on both a gasoline and a diesel basis. *However, even though we provide emissions results on an individual fuel basis, it is still not appropriate to compare our GHG emissions values for each product to other studies—as they use different assumptions and emission allocation methods.*

Figure 2

**Well-to-tank emissions from two separate
studies with different allocation methods**
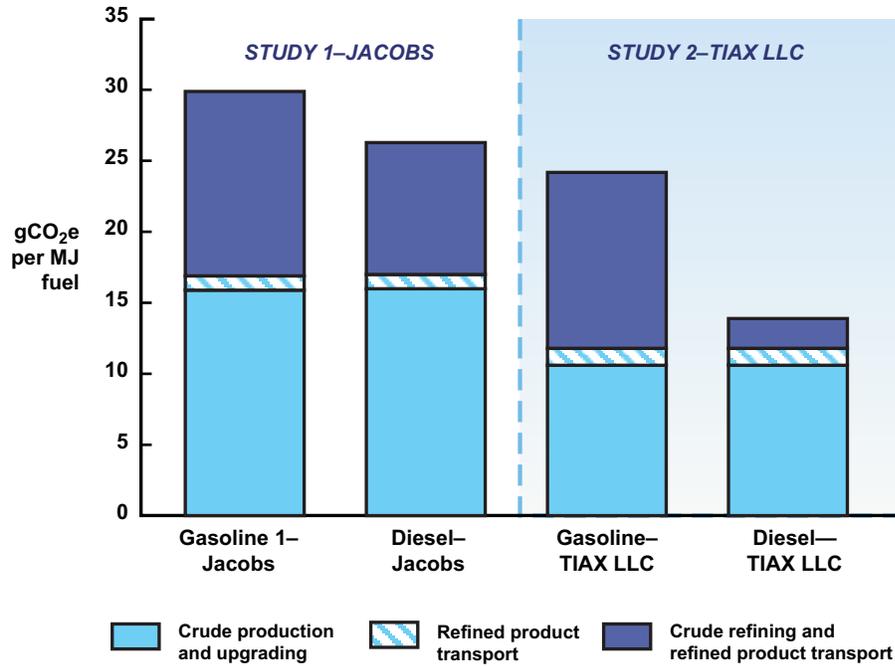
Source: TIAX LLC, "Comparison of North American and Imported Crude Oil Lifecycle GHG
Emissions," July 2009, and Jacobs Consultancy, "Life Cycle Assessment Comparison of
North American and Imported Crudes," July 2009.

Figure 3

IHS CERA's full barrel of refined product basis
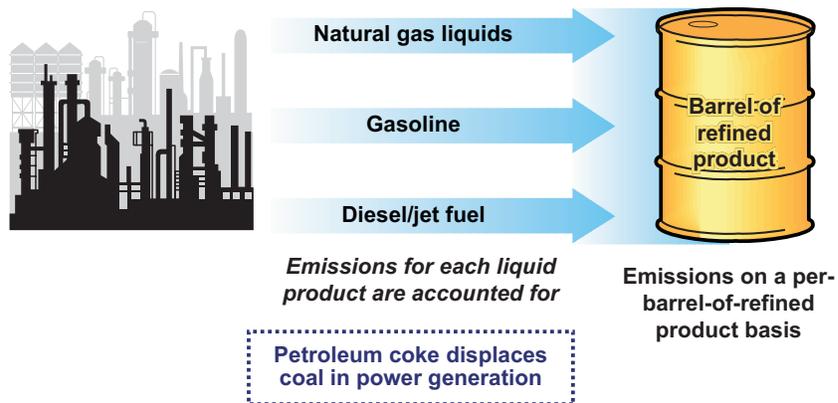
Source: IHS CERA.
Note: Refined product basis assumes high conversion refinery that produces only
three liquid products and no heavy oil.
20516-9_3110

To compare the results among studies, we categorized the life-cycle GHG emissions into the groupings shown in Figure 4 (see Appendix 1, Part B for a detailed description of GHG emissions included within each category).

The term *well-to-tank* includes all the emissions from production through refined product transport, while *well-to-wheels* includes all emissions from production through combusting the refined product in a vehicle.

Step 3: Normalizing other assumptions. Since all studies use different assumptions in modeling GHG emissions, it's not valid to directly compare the absolute GHG emissions estimates among studies. Instead of measuring the actual difference in crude oil GHG intensity, such a comparison would measure the differences among the studies' assumptions and models. (To help illustrate this point, look at the difference in estimates between the two studies of refined products from the same crude oil in Figure 3. The absolute estimates are quite different because the models and assumptions used are unique for each study).

For instance, if a study were to assume that a complex refinery was used to convert the crude oil to refined products, it would assume about three times more energy for the refining step

Figure 4

**IHS CERA life-cycle meta analysis framework:
System boundary and category**
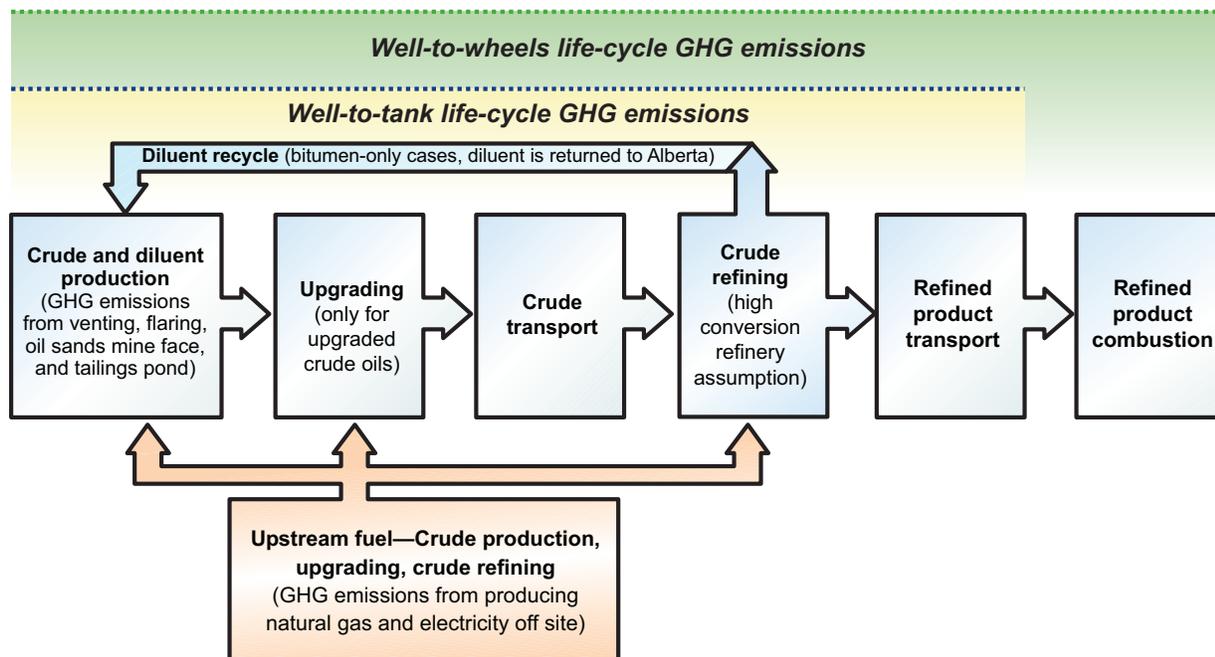
Source: IHS CERA.
20516-10

than if a simple refinery were assumed.* In this scenario, in comparing the GHG emissions between two similar crudes, one could (wrongly) conclude that the crude using the simple refinery assumption was less GHG intense. However, since the qualities of the crudes are similar, the majority of the difference is derived from the differing refinery assumptions—not the crude oils themselves.

To resolve these types of discrepancies and ensure uniformity in crude oil comparisons, the data from different studies must be normalized—creating a comparable set of best estimates for each crude oil.

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*Compared to a simple refinery (hydroskimming), a complex conversion refinery takes more energy and creates more refined products per barrel of crude consumed (since it cracks the heavier parts of the crude oil into light and valuable transportation products). While the simple refinery uses less energy per barrel of crude consumed, it also creates less transportation fuel and instead produces low-quality fuel oil.

PART III: THE RESULTS—GHG EMISSIONS FOR US OIL SUPPLY

This section highlights the scope, purpose, and results of our analysis as well as some tips for navigating the plethora of data sets that compare the GHG emissions of crude oils.

SCOPE AND PURPOSE

The purpose of this report is to generate a broad estimate of crude oil GHG emissions data to help inform discussions on GHG emissions from sources of US crude supply and oil sands.

Tight-boundary and wide-boundary results

In our earlier meta-analysis (the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right,* September 2010), we drew the boundary for measuring GHG emissions tightly around the production facilities and the refinery. Our scope did not consider a wider boundary for estimating emissions. For instance, it did not include the GHG emissions that occur outside of the crude production or refining facilities, such as emissions from producing and processing natural gas used in oil production or emissions from off-site electricity production.

In the past two years, as new studies of life-cycle emissions for crude oil have been released, most new data account for wider boundaries. Consequently, in this update we have presented the results of our analysis with both a tight and a wide system boundary. However, as the system boundary is drawn wider, the level of uncertainty associated with measuring the emissions increases.

Land use emissions are excluded

We did not include emissions for land use change in our meta-analysis. For oil developments, direct emissions from land use change arise when the oil development is constructed and the land is converted from its previous use, such as agriculture or forest. Some GHG emissions occur when carbon stored in the land is disturbed by oil developments; others result from loss of vegetation on the land, which absorbs carbon as it grows. For conventional petroleum and oils sands in situ, the land use emissions are thought to be relatively small, while for oil sands mining they are thought to be more substantial. However, across the studies in our meta-analysis that included land use, some conventional sources had emissions estimates in the range of oil sands mining.* And while our meta-analysis has a number of sources that estimate GHG emissions for oil sands, the values are derived mostly from a single study, Yeh (2010). Since it is difficult to measure land use emissions, studies are limited, and methods to quantify them are still evolving, we did not include these emissions within the scope of our meta-analysis.

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*CARB-OPGEE (2012) land use estimates for crudes from Ecuador and Colombia ranged between 4.7 and 5 kilograms of carbon dioxide equivalent ($kgCO_2e$) per barrel of refined product, while the estimate for oil sands mining was 7 $kgCO_2e$ per barrel of refined product.

Treatment of electricity cogeneration

For oil sands mining, projects always produce on-site power. The majority of the electricity is consumed at the facility; and on a per-barrel-of-oil-produced basis, a relatively small amount is exported. Such exports are accounted for in our results since studies considering the wide-boundary and these impacts were included in our meta-analysis.

For oil sands in situ, about half of the production comes from facilities with some amount of electricity cogeneration (meaning that electricity is generated along with the steam used in oil production and the power is exported). For these sites, typically between 40% to 60% of the steam load uses cogeneration. Wide-boundary GHG emissions are reduced by between 5% and 14% when cogeneration is included (or, on a well-to-wheels basis, by 1% or 2%).*

For California heavy oil (which also uses steam for oil production), most production comes from facilities that have some electricity cogeneration and export of power. For these sites, between 10% and 90% of the steam load uses cogeneration. Wide-boundary GHG emissions are reduced by between 4% and 30% when cogeneration is included (or on a well-to-wheels basis, by 1% to 5%).**

Estimating the cogeneration credit and comparing results among studies is challenging. Each study uses different methods for crediting displaced electricity and different assumptions and models regarding the efficiency of cogeneration. Moreover, in the case of steam-assisted oil recovery (which exports an order of magnitude more electricity per barrel of oil produced than an oil sands mine), when a tight-boundary basis is applied, the inclusion of cogeneration distorts the results somewhat.*** To ensure that the tight-boundary results are comparable across our meta-analysis and to our past analyses for oil sands in situ and California heavy oil, we have not included the impacts from cogeneration within our results.

AVERAGE US CRUDE REFINED (2005) BASELINE

DOE/NETL (2008) estimated the life-cycle GHG emissions for the average crude refined in the United States in 2005. This estimate was included in the US Renewable Fuels Standard, and the analysis is often used to describe GHG emissions from oil sands and other crudes.

Common baselines are useful to provide a consistent point of reference among studies. Many studies refer to DOE/NETL's "Average US Crude Refined (2005)" baseline, and we included our estimate of a 2005 baseline value in our meta-analysis. We did not adjust the crudes included in DOE/NETL baseline to be more representative of the average crude refined in the United States today. The 2005 baseline is a common point of comparison among studies, and our goal is to keep our results comparable with our original study. Furthermore, if we adjust the amount of crude from each country to more closely reflect today's crude supply

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*For SAGD: Source: Charpentier (2011).
**Source: IHS CERA reran the CARB-OPGEE (2012) models, removing the cogeneration assumption, and compared the results with and without cogeneration.
***To raise the same volume of steam, cogeneration requires about 30% more energy than a typical steam boiler, boosting the emissions accounted for in the tight-boundary case. The benefit from the power exports (and cogeneration) are only considered in the wide-boundary case—when the electricity exports are used to offset the extra energy required to raise steam.

(keeping the same carbon intensities as the original study), the baseline does not change materially.

Although we refer to this baseline within this report, the actual GHG emissions from crude oil refined in the United States cannot be calculated precisely. There are simply too many crude oils to accurately track and quantify the GHG emissions for each crude oil consumed. To approximate the emissions, we used the country-level estimate for each major source of crude oil from DOE/NETL (2008). The margin of error associated with a country-level estimate is typically larger than for any individual crude oil source, owing to the numerous crude oils produced within each country and the difficulties of modeling and finding data for each crude type.

CHANGES IN THIS UPDATE

Responding to suggestions received following the release of the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right,* we have made the following key changes in this 2012 update:

- **An update of the studies included in our meta-analysis.** To improve the meta-analysis quality, we've used a more current set of studies on which to base our meta-analysis.

- **A more detailed explanation of the methodology of our meta-analysis.** This report includes an appendix with detailed documentation on how we transform the original studies' results to a consistent basis for comparison.

- **Widening the system boundary.** In this update we include emissions from producing upstream fuels (our wide-boundary case).

- **More oil sands production methods.** This update includes estimates of all major sources of oil sands production, including primary production using the CHOPS, polymer methods, and mining bitumen using PFT.

- **Making results available on a gasoline and diesel basis.** Consistent with our original meta-analysis, this update reports GHG emissions on a full-barrel-of-refined-products basis. But we now also state results on both gasoline and diesel energy content bases (see Appendix 1, Part F).

HOW DO LIFE-CYCLE EMISSIONS OF OIL SANDS COMPARE TO THOSE OF OTHER SOURCES OF CRUDE OIL?

Because different types of GHG emissions estimates are needed to answer different questions, we consider the emissions of two types of oil sands products in this analysis. When comparing the incremental GHG emissions from growing oil sands production on a Canadian or even a global basis, considering the emissions from products entirely derived from oil sands is appropriate. Consequently, we estimated the emissions from products derived wholly from oil sands in this report. For other questions, such as the impact on US transportation emissions of consuming oil sands crudes instead of alternatives, one must consider the product actually

imported, refined, and ultimately consumed in the United States (a mix of oil sands and less carbon-intensive diluents). Thus we also estimated the emissions from the average oil sands product consumed in the United States, which accounts for the actual product pipelined to and refined in the US market.

Fuels produced entirely from oil sands

IHS CERA's meta-analysis of 12 publicly available sources found that the well-to-wheels GHG emissions from refined products wholly derived from oil sands are 11% higher than the average crude refined in the United States in 2005 (results ranged from 4% to 18%) when the system boundary is drawn tightly around the production facilities and the refinery (the "tight boundary"). These bookend values represent a 4% average for mining bitumen and an 18% average for SCO from SAGD production and upgrading. They do not encompass all possible oil sands emissions but instead are the average values taken across the range of studies included within our meta-analysis (see Figure 5).

Expanding the boundary for measuring GHG emissions beyond the facility gate—the wide-boundary case—results in higher emissions from oil sands crudes. In this case, fuels produced solely from oil sands result in average well-to-wheels GHG emissions that are 14% higher than the average crude refined in the United States (results ranged from 5% to 23%). These bookend values represent a 5% average for primary oil sands production and a 23% average for SCO in-situ production from SAGD.

Although oil sands–derived crudes are more carbon intensive than the average crude oil refined in the United States, they are one among several high-emissions crudes. Other carbon-intensive crude oils are produced, imported, or refined in the United States, including crudes from Venezuela, Nigeria, Iraq, and California heavy oil production.

These GHG estimates represent average values across the range of studies included in our meta-analysis. We have not included the high and low ranges for each crude, since the magnitude of the range is purely a function of the number of estimates available, not the uncertainty associated with the reported value (crudes with more sources will have higher ranges).

Average oil sands barrel refined in the United States (2011)

The results of our meta-analysis show a relatively wide range of GHG emissions from oil sands production (depending on the production method deployed). To present a representative average of this range, IHS CERA estimated the likely mix of oil sands products refined in the United States in 2011—a mix of bitumen, dilbit, and SCO. Using the tight system boundary, oil sands products refined in the United States result in well-to-wheels GHG emissions about 9% higher than those of the average crude. When the wider system boundary is applied, oil sands products refined in the United States result in well-to-wheels GHG emissions about 12% higher than those of the average crude.

Figure 5

Well-to-wheels GHG emissions for oil sands and other crudes

(tight boundary)
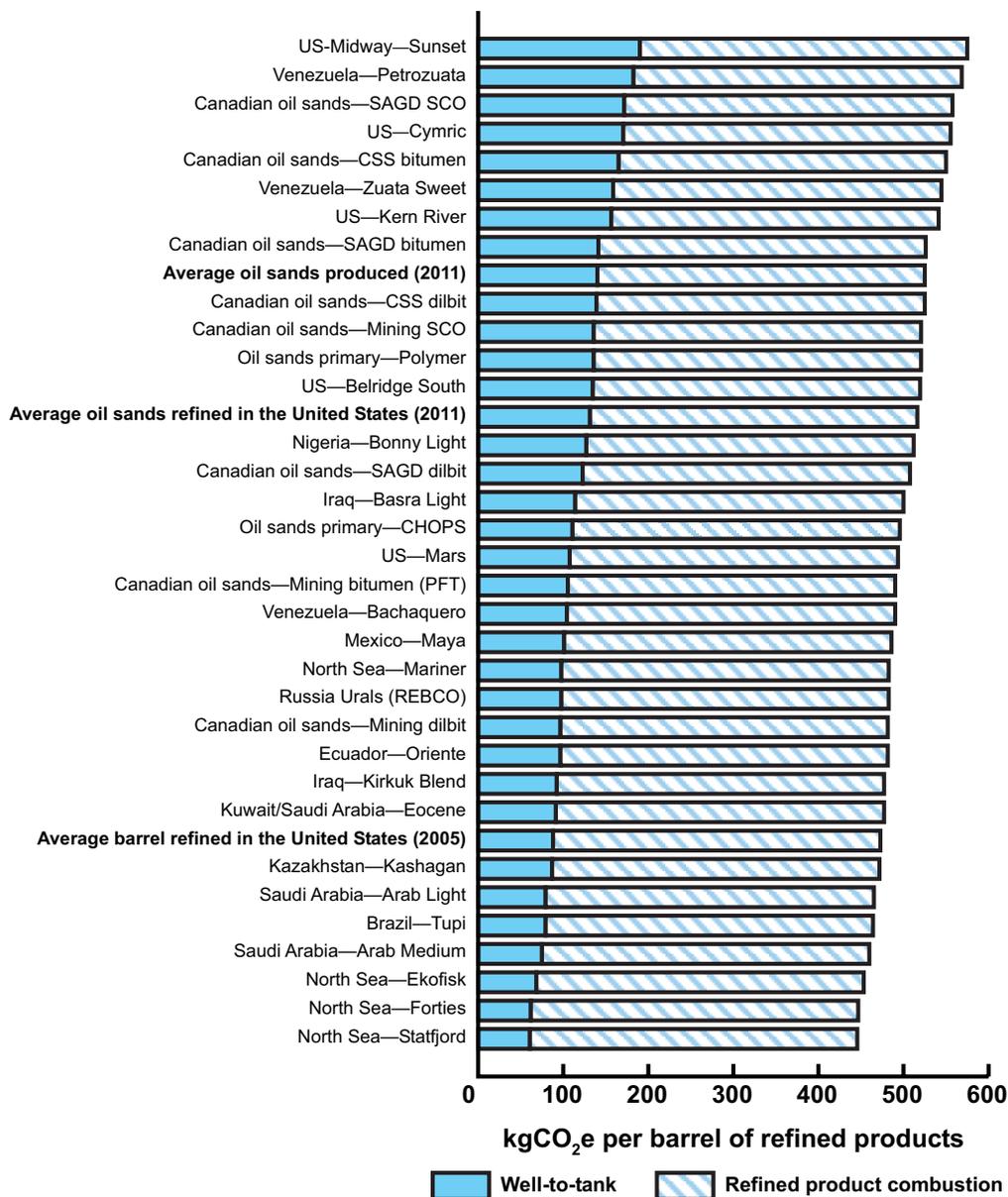
kgCO$_2$e per barrel of refined products

■ Well-to-tank   ▨ Refined product combustion

Source: IHS CERA meta-analysis sourcing data from IHS CERA (2009), Environment Canada (2010), DOE/NETL(2008), Jacobs (2012), Jacobs (2009), Charpentier (2011), GHGenius (2011), GREET (2012), CARB-OPGEE (2012), Yeh (2010), EIA's past oil sands, and Alberta Environment.
Notes: Tight boundary includes direct emissions from the oil production site and facilities only.
Refining data sourced from Jacobs (2012).
Average oil sands refined in the United States (2011) assumes 7% SAGD SCO, 22% mining SCO, 20% CSS dilbit, 28.5% SAGD dilbit, 16% primary (CHOPS), 4% SAGD bitumen, and 3% CSS bitumen. "Average oil sands produced (2011)" assumes 50% mining SCO, 5% SAGD SCO, 15% SAGD bitumen, 17% CSS bitumen, and 13% primary (CHOPS). All dilbit blends are assumed 28% diluents; it is also assumed that the dilbit is consumed in the refinery with no recycle of diluents. All oil sands cases marked "bitumen" assume that diluent is recycled back to Alberta, and only the bitumen part of the barrel is processed at the refinery. For crude production using steam (California heavy crudes and oil sands in situ), impacts from cogeneration of electricity were not included in results.
21012-1

This analysis assumes that bitumen blends make up about half of the oil sands products refined in the United States.* The most common bitumen blend, dilbit, is a combination of bitumen and diluents such as natural gas condensates. Dilbit has lower life-cycle emissions than bitumen because only about 72% of the dilbit barrel is derived from bitumen, with the remainder coming from less carbon-intensive diluent.** Although oil sands bitumen must be shipped to the United States in the form of dilbit or SCO (since bitumen alone is too thick to transport in pipelines), it is now possible for some US refiners to consume only bitumen, and this has been accounted for in our average value (see Appendix 1, Part E for more details).

Table 2 at the end of this report presents our well-to-wheels GHG emissions estimates for oil sands and other crude oils on a per-barrel-of-refined-products basis (tight-boundary and wide-boundary cases). See the box "Comparing 2012 update to our previous results" to understand differences from the prior study. Also, see Appendix 1, Part F for a summary of results on a gasoline and a diesel energy content basis.

UNDERSTANDING DIFFERENCES IN GHG INTENSITY

A wide range of studies compares the GHG intensity of oil sands with other crudes, and emissions estimates varied across the studies we examined. Differences among the estimates were related to data quality and availability, allocation of emissions to the various products produced in the refinery, and the system boundaries used for the life-cycle analysis.

Sometimes the "emissions gap" between oil sands and other sources of crude is much higher than in the IHS CERA analysis. Analyses that show a much wider emissions gap often are based on comparisons of GHG emissions from only part of the life cycle—such as only the extraction phase—rather than the complete process. Other studies focus only on specific oil sands operations—such as in-situ facilities with higher-than-normal energy use—rather than taking into account the average of all oil sands operations. Our results are a broad estimate of the average across all studies considered rather than outliers.

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*Oil sands 2011 exports assume 7% SAGD SCO, 22% mining SCO, 20% CSS dilbit, 28.5% SAGD dilbit, 16% primary production (CHOPS), 4% SAGD bitumen, and 3% CSS bitumen. See detailed calculation and assumptions in Appendix 1, Part E.
**Our assumption is that 72% of the barrel is bitumen, and the volume of bitumen to diluent varies with the density of the bitumen and the condensate; however, this is a typical value.

Comparing the 2012 update with our previous results

How do the results of this update compare with our previous analysis, the September 2010 IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply*?

Our previous study results are comparable to the tight-boundary results in this update. Our 2010 findings concluded that products wholly derived from oil sands had life-cycle GHG emissions 5% to 15% higher than the average crude refined in the United States. This range is comparable to the tight-boundary results of this update—4% to 18% higher than the average crude refined in the United States—considering the margin of error in these estimates.

Although the range of results is similar to those in the past report, the estimates for some specific oil sands extraction methods have increased with this update. For instance, this analysis concludes that the average oil sands refined in the United States in 2011 had GHG emissions 9% higher than the average crude refined in the United States (tight boundary). Our previous study concluded that in 2009, the average oil sands refined in the United States was 6% higher.

Comparing the previous results to this update, some of the difference results from a more detailed estimate for US oil sands imports—accounting for production from bitumen only, primary, and SCO from SAGD (these imports were not considered in the previous study). However, the majority of the difference is because the GHG emissions estimates are slightly higher for some oil sands extraction methods than in the previous analysis. For instance, in this update SAGD dilbit GHG emissions are 7% higher than the average crude refined in the United States, compared with 5% before; mining SCO emissions are now 10% higher, compared with 6% before; and CSS dilbit emissions are now 11% higher, compared with 7% in the previous analysis.

The difference in results between this update and our past report does not necessarily indicate a change in the carbon intensity of oil sands production. Instead, the difference stems from the new set of source studies used in this update. As life-cycle analysis has evolved, the methods and data used for estimating the GHG emissions from oil sands and other crudes have changed. For example, a few years ago, estimates for the GHG emissions for producing diluents (used in bitumen blends) were sparse, and IHS CERA used the only estimate we found of 8 $kgCO_2e$ per barrel. Since then, Jacobs (2012) has concluded that the emissions for diluents are materially higher, at 37 $kgCO_2e$ per barrel. We used the new value in this update. Other estimates have shifted as models and methods have developed; compared with our previous update, updated versions of GHGenius and GREET models have been released, and totally new models for estimating the GHG emissions of crude oil are now available—such as the model used by Charpentier (2011) and the OPGEE (2011) model used in the CARB-OPGEE (2012) estimates.

PART IV: LOOK TO THE FUTURE

In recent years, much of the dialogue on emissions from oil sands has been about methodology, including how to measure emissions over the life cycle and how to compare emissions from various oil sands extraction methods with those of other crudes. Indeed, in our previous meta study and this update, we have addressed the question of how GHG emissions from oil sands compare with those of other crudes today. But it is also important to ask the question, How can the oil sands industry reduce its future GHG emissions intensity?

TRACK RECORD OF CONTINUOUS IMPROVEMENT

The GHG intensity of oil sands production has declined over time. Since 1990, the GHG intensity of mining and upgrading operations has fallen by 37% on a well-to-tank basis. Since the inception of SAGD about a decade ago, well-to-tank emissions have declined by 8%.* For mining, major drivers of GHG emissions reductions have included hydrotransport, improvements in bitumen extraction, shifting to natural gas cogeneration for electricity and steam, and efficiency improvements in upgrading. For SAGD (the most recent innovation in oil sands extraction), major drivers of GHG emissions reductions have included improved reservoir characterization and wellbore placement, use of electric submersible pumps, and wellbore liner improvements. These technical advances have reduced the steam-to-oil ratio (SOR), a critical metric of efficiency in SAGD production. Further gains in GHG intensity are still possible and continue to be pursued by industry.

Despite reductions in the energy intensity of each barrel of oil produced, the absolute level of GHG emissions has grown as oil sands production volumes have increased.

WHERE IS THE INDUSTRY HEADED?

Several promising technologies are on the horizon for further reducing the GHG intensity of oil sands production, ranging from ongoing efficiency improvements to totally new methods for extracting bitumen.

For in-situ extraction, the focus is on decreasing steam use. Ongoing efficiency improvements and the penetration of new hybrid steam-solvent technologies that partially substitute solvents for steam could reduce steam use—and thus energy and GHG intensity—of in-situ production by perhaps 5% to 20% (well-to-tank basis). Yet even if solvent techniques were to cut steam injection for in-situ recovery by half, on a well-to-wheels basis emissions would still be greater than for the average crude refined in the United States (2005 baseline). But this strategy would put oil sands in-situ emissions lower than some other US supply sources, including some crudes from Venezuela, Africa, Iraq, and California.

The original mining operations always marketed SCO. However, a new mining operation is under construction that will not upgrade to SCO; instead the bitumen will be shipped to market as dilbit. On a well-to-wheels basis, the process is expected to result in GHG emissions that are 6% lower than for a traditional mine and upgrading operation.**

*See the IHS CERA Special Report *Oil Sands Technology: Past, Present, and Future.*
**This benefit compares the emissions for producing a barrel of refined products from mining bitumen to mining SCO.

Looking beyond 2030, totally new methods for extracting bitumen could become widely adopted. Such breakthrough technologies could include electric heating, solvents, radio waves, in-situ combustion, and underground tunnels. Many of these ideas are being tested in field pilots now. Using low-emission, small nuclear plants instead of natural gas would be another game changer. The potential benefits from these revolutionary technologies are probably 15 to 20 years away owing to the time lag between a successful pilot and broad commercial deployment. Carbon capture and storage systems would likewise lower GHG emissions.

With an aim of speeding up the advancement of green techniques, major oil sands companies have joined under the banner of Canada's Oil Sands Innovation Alliance (COSIA). The group has agreed to share environmental research, technology, and best practices. Although innovation under COSIA is in no way assured, the mandate of sharing technology and information is likely to be beneficial and aims to support the timely development and deployment of new ideas.

Although technical advancements in oil sands production are possible, they are not inevitable. As with conventional production, reservoir quality is one factor that could push back against technical advances. Generally, the first generation oil sands projects selected some of the best parts of the oil sands deposit—those with characteristics that allow the most efficient recovery. As reservoir quality declines, more energy is required to extract the bitumen. This is especially the case with in-situ production, where more steam injection is needed to stimulate the flow of bitumen in poorer quality reservoirs. But technology advances may mean that all other things aren't equal. In other words, two trends—one of declining reservoir quality and the other of continued technical advances in oil sands production methods—will exert opposing forces on GHG emissions trends. Another factor is economics: money still matters. Even if a new green technique reduces emissions, it will not be adopted if it is not competitive with established methods.

CONCLUSION

The purpose of this report is to generate a broad set of crude oil GHG emissions data to help inform the dialogue on GHG emissions from US crude supply. In these types of discussions, it is important that GHG estimates represent average values. Our results are a best estimate of the average value across a group of estimates, not outliers.

When comparing results across unique sources, meta-analysis matters. Emissions estimates from different sources use different assumptions in modeling GHG emissions from crude oil. In directly comparing results among independent studies, a significant part of the difference measured is due to unique study assumptions, not actual differences in the carbon intensity of the crude oils being compared.

Certainly new studies will emerge on the GHG intensity of oil sands and other crudes. As more data on oil sands and other crudes become available, our meta-analysis results are sure to shift. Yet if history repeats itself, the industry will continue to make strides—potentially significant ones—toward increasing the efficiency of production for the oil sands and for other crude oil sources as well.

REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Washington, DC, on 15 November 2011 to provide an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to quantifying GHG emissions from oil sands and other crude oils. Additionally, a number of participants reviewed a draft version of this report. Participation in the focus group or review of the draft report does not reflect endorsement of the content of this report. IHS CERA is exclusively responsible for the content of this report.

Alberta Department of Energy

American Petroleum Institute (API)

BP Canada

Canadian Association of Petroleum Producers (CAPP)

Canadian Natural Resources Ltd.

Canadian Oil Sands Limited

Cenovus Energy Inc.

Chevron Canada Resources

ConocoPhillips Company

Devon Energy Corporation

Energy and Environmental Solutions, Alberta Innovates

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

Jacobs Consultancy

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Pembina Institute

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

TIAX LLC

Total E&P Canada Ltd.

TransCanada Corporation

University of Toronto

US Department of Energy, National Energy Technology Laboratory (DOE/NETL)

IHS CERA TEAM

JACKIE FORREST, IHS CERA Senior Director, Global Oil, is an expert in all aspects of petroleum evaluations, concentrating on refining, processing, upgrading, and products. In addition to contributing to the IHS CERA Global Oil Advisory Service, Ms. Forrest heads the IHS CERA Oil Sands Energy Dialogue and Canadian Oil Sand Analytics services. She actively monitors emerging strategic trends related to oil sands among capital projects, economics, policy, environment, and markets. She is the author of several IHS CERA Private Reports, such as a recent investigation of West Texas Intermediate oil prices. Additional contributions to research include reports on the life-cycle emissions from crude oil, the impacts of low-carbon fuel standards, and the role of oil sands in US oil supply. She led a team that developed unconventional oil outlooks for North America and recommendations in the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources*, covering the Canadian oil sands, US oil sands, tight oil, oil shale, and Canadian heavy oil. Ms. Forrest was the IHS CERA project manager for the Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance,* a comprehensive assessment of the benefits, risks, and issues associated with oil sands development. She also writes a regular column in *Alberta Oil* magazine called "Eye on the Oil Sands." Before joining IHS CERA Ms. Forrest was a consultant in the oil industry, focusing on technical and economic evaluations of refining and oil sands projects. She is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

SAMANTHA GROSS, IHS CERA Director, focuses on the interaction of investment decisions with the complex landscape of policy, environment, and technology. Ms. Gross was the IHS CERA project manager for the global energy reports *Energy for Economic Growth*, *A New Era for Gas*, *Towards a More Energy Efficient World*, and *Thirsty Energy: Water and Energy in the 21st Century*, all produced in conjunction with the World Economic Forum. She leads the environmental and social aspects of IHS CERA's ongoing Canadian Oil Sands Dialogue, including consideration of water use and quality, local community impacts, and aboriginal issues. Additional contributions to IHS CERA research include reports on the water impacts and greenhouse gas emissions from unconventional gas production, US light vehicle fuel efficiency regulations, and low-carbon fuel standards. Before joining IHS CERA Ms. Gross was a Senior Analyst with the Government Accountability Office. Her professional experience also includes providing engineering solutions to the environmental challenges faced by petroleum refineries and other clients. Ms. Gross holds a BS from the University of Illinois, an MS from Stanford University, and an MBA from the University of California at Berkeley.

JEFF MEYER, IHS CERA Associate, Global Oil, focuses on oil market fundamentals and market developments. He contributes to the IHS CERA *World Oil Watch* and monthly Global Oil Market Briefing. Prior to joining IHS CERA Mr. Meyer was a correspondent for Dow Jones Newswires, based in Shanghai, where he covered China's capital markets and economy. At Dow Jones he also contributed to *The Wall Street Journal.* He has held short-term positions with J.P. Morgan's Emerging Asia economic research team and with the US Treasury's Office of South and Southeast Asia. Mr. Meyer holds a BA from Haverford College and master's degrees from New York University and from Johns Hopkins University School of Advanced International Studies. He is proficient in Mandarin.

We also recognize the contribution of Kevin Birn, IHS CERA Associate Director, Global Oil, to this report.

Table 2

Well-to-wheels GHG emissions for oil sands and conventional crude oils (kgCO$_2$e/barrel of refined product)— Tight and wide boundary results

Crude name	Tight Boundary								Wide Boundary				
	Crude production (includes venting and flaring, dilbit production, mine face, and tailings)	Upgrading	Crude transport	Crude refining	Refined product transport	Refined product combustion	Well-to-wheels (tight boundary)	Percent difference from "average US barrel refined in the United States (2005)" (tight boundary)	Crude production: Upstream fuel	Upgrading: Upstream fuel	Crude refining: Upstream fuel	Well-to-wheels (wide boundary)	Percent difference from "average US barrel refined in the United States (2005)" (wide boundary)
US–Midway–Sunset	128		4	56.0	2.3	385	575	22%	18		17.5	610	25%
Venezuela–Petrozuata	21.5	103	4	51.9	2.3	385	568	20%		3.0	13.5	585	20%
Canadian oil sands: SAGD SCO	65	51	8	46.0	2.3	385	557	18%	23	3	14.5	598	23%
US–Cymric	111		4	53.2	2.3	385	556	18%	13		13.5	583	20%
Canadian oil sands: CSS bitumen	89		12	62.0	2.3	385	550	16%	23		18.5	591	21%
Venezuela–Zuata Sweet	18.9	93	4	41.3	2.3	385	544	15%		3.0	14.5	562	15%
US–Kern River	89		4	61.2	2.3	385	541	14%	8		17.5	567	17%
Canadian oil sands: SAGD bitumen	65		12	62.0	2.3	385	526	11%	23		18.5	568	17%
Average oil sands produced (2011)	47	28.1	10	53.0	2.3	385	525	11%	14	1.7	16.2	556	14%
Canadian oil sands: CSS dilbit	74		10	53.5	2.3	385	525	11%	17		16.5	558	15%
Canadian oil sands: Mining SCO	28	51	8	46.0	2.3	385	521	10%	10	3	14.5	548	13%
Oil sands primary–Polymer	63		10	60.4	2.3	385	521	10%			17.5	538	11%
US–Belridge South	81		4	47.7	2.3	385	520	10%	8		13.5	542	11%
Average oil sands refined in the United States (2011)	53	15	10	53	2	385	517	9%	13	0.9	16.2	547	12%
Nigeria–Bonny Light	77		9	39.2	2.3	385	512	8%			13.5	526	8%
Canadian oil sands: SAGD dilbit	57		10	53.5	2.3	385	508	7%	17		16.5	541	11%
Iraq–Basra Light	60		9	43.2	2.3	385	500	6%			13.5	513	5%
Oil sands primary–CHOPS	38		10	60.4	2.3	385	496	5%			17.5	513	5%
US–Mars	60		4	41.8	2.3	385	493	4%			13.5	507	4%
Canadian oil sands:Mining bitumen (PFT)	29		12	62.0	2.3	385	491	4%	10		18.5	519	7%
Venezuela–Bachaquero	35		4	63.7	2.3	385	490	4%			17.5	507	4%
Mexico–Maya	42		4	51.8	2.3	385	486	3%			13.5	499	3%
North Sea–Mariner	23		9	64.0	2.3	385	483	2%			17.5	501	3%
Russia Urals (REBCO)	47		9	39.6	2.3	385	483	2%			13.5	496	2%
Canadian oil sands: Mining dilbit	31		10	53.5	2.3	385	482	2%	7		16.5	506	4%
Ecuador–Oriente	46		4	44.5	2.3	385	482	2%			13.5	495	2%
Iraq–Kirkuk Blend	45		9	36.5	2.3	385	477	1%			13.5	491	1%
Kuwait/Saudi Arabia–Eocene	25		9	55.9	2.3	385	477	1%			17.5	494	2%
Average US barrel refined in the United States (2005)	36		6	43.2	2.3	385	473	0%			14.0	487	0%
Kazakhstan–Kashagan	46		9	29.6	2.3	385	472	0%			13.5	485	0%
Saudi Arabia–Arab Light	28		9	40.3	2.3	385	465	-2%			13.5	478	-2%
Brazil–Tupi	29		4	43.7	2.3	385	464	-2%			13.5	477	-2%
Saudi Arabia–Arab Medium	22		9	41.6	2.3	385	460	-3%			13.5	474	-3%
North Sea–Ekofisk	22		9	35.0	2.3	385	454	-4%			13.5	467	-4%
North Sea–Forties	19		9	30.9	2.3	385	447	-6%			13.5	460	-5%
North Sea–Statfjord	14		9	35.0	2.3	385	445	-6%			13.5	459	-6%

Source: IHS CERA meta-analysis sourcing data from IHS CERA (2009), Environment Canada (2010), DOE/NETL (2008), Jacobs (2012), Jacobs (2009), Charpentier (2011), GHGenius (2011), GREET (2012), CARB-OPGEE (2012), Yeh(2010), past oil sands EIA's, and Alberta Environment.
Tight boundary includes direct emissions from the oil production site and facilities.
Wide boundary adds emission for upstream fuels— natural gas and electricity produced off site.
Refining data sourced directly from Jacobs (2012).
"Average oil refined in the United States (2011)" assumes 7% SAGD SCO, 22% mining SCO, 20% CSS dilbit, 28.5% SAGD dilbit, 16.5% primary (CHOPS), 4% SAGD bitumen, and 3% CSS bitumen.
"Average oil sands produced (2011)" assumes 50% mining SCO, 5% SAGD SCO, 15% SAGD bitumen, 17% CSS bitumen, and 13% primary (CHOPS).
All dilbit blends are assumed 28% diluents and the remainder bitumen.
All oil sands cases marked "dilbit" assume that the dilbit is consumed in the refinery with no recycle of diluents.
All oil sands cases marked "bitumen" assume that diluent is recycled back to Alberta, and only the bitumen part of the barrel is processed at the refinery.
For crude production using steam (California heavy crudes and oil sands insitu) impacts from cogeneration of electricity were not included in results.