# IHS CERA Canadian Oil Sands Dialogue

**Frequently Asked Question**

**Updated July 2011**

## Frequently Asked Questions (FAQ) on IHS CERA's Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right?

The Canadian oil sands have been one of the most important sources of global oil supply growth during the past decade and are poised to soon become the single largest source of US oil imports. Their growing importance to North American oil supply and energy security has also generated debate on the overall impact of oil sands development. Beginning in 2009, IHS CERA started the Oil Sands Dialogue, a forum that brings together government, industry and non-governmental organizations (NGOs) to discuss issues related to the oil sands industry. IHS CERA has issued a number of publicly available reports as part of our Oil Sands Dialogue.

Better understanding of the environmental impact of oil sands development—particularly the level of green house gas emissions (GHG)—is one of the objectives of our dialogue. In September 2010, IHS CERA released a report that estimated the life-cycle GHG emissions from oil sands—an issue with a wide range of views in the public arena. This report has generated significant interest since it provides a transparent assessment of this issue. The complexity of greenhouse gas emissions accounting makes a transparent analysis all the more important.

The purpose of this "FAQ" is to clarify questions that have been raised in the course of our ongoing dialogue. In order to advance understanding of these issues we encourage others doing similar studies to provide a comparable level of transparency about their analysis and methodology.

## A study by Brandt*(released January 2011) concludes that GHG emissions from oil sands are 23 percent higher than the average crude consumed in Europe.  IHS CERA concludes that products derived wholly from oil sands have GHG emissions 5 to 15 percent higher than the average crude consumed in the United States. Why are these results different?

There are two key differences in the basis and methodology between the Brandt and IHS CERA studies - making the results from the two studies not directly comparable.

- **Difference in the "average crude" comparison—US versus European averages.** The Brandt study uses the average crude oil consumed in Europe as the basis for comparing GHG emissions with oil sands. IHS CERA uses the average crude oil consumed in the United States, which is the only significant export market for oil sands. Oil sands are not refined in Europe. Because the average crude oil consumed in Europe is lighter and lower-carbon than the average crude consumed in the United States, the results from the Brant study are about 5 percent higher than comparisons to the US crude average (on a life cycle or "well-to-wheels" basis).

- **Difference in the range of oil sands products.** Another difference  is the IHS CERA study considered emissions for a range of oil sands products from heavy bitumen to light Synthetic Crude Oil (SCO)**. The Brandt study considered emissions from SCO only.  SCO constitutes about 55 percent of total oil sands output. The range of oil sands products used in the IHS CERA study represent of the full range of oil sands output.

When the IHS CERA results for SCO are converted to the same basis as the Brandt study, our results are in the range of the Brandt study.

## Why do studies vary in the basis they use for life cycle comparisons?  Some studies compare the GHG emissions from producing gasoline while others, including the IHS CERA report, compare the emissions of all refined products produced from a barrel of crude oil.

Both comparisons are valid, depending on the question being asked.  Describing emissions on a gasoline basis is useful when comparing emissions from making the same fuel from a variety of different sources of crude oil.  A basis that includes all refined products is more appropriate when considering the overall emissions impact of introducing a different source of crude oil to a refining system. A barrel of crude oil produces a number of products, not just gasoline.

A basis that includes all refined products reduces an important source of uncertainty in studies comparing GHG emissions. Allocation of emissions among numerous refinery products is a key challenge in life-cycle analysis, and studies vary greatly in their assumptions. Some conclude that the emissions for producing gasoline are 5 times higher than the energy for producing diesel, while others find emissions for producing gasoline and diesel are almost the same.  The difference stems from the assumptions that each study author makes about refinery configuration and how to allocate emissions across the various refined products.  Including emissions from all products removes this potential source of error. IHS CERA plans to update our meta-analysis in late 2011/ early 2012. In the forthcoming update we will publish the results on both a gasoline-only and full barrel of refined product basis. This will facilitate comparison between our results and that of other studies.

**Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries, Stanford University, Adam Brandt (January, 2011).*

*** Synthetic Crude Oil – is produced by upgrading the heavy bitumen to a sweet light crude with API gravity typically greater than 33 degrees.*

## Are the assumptions and inputs behind IHS CERA's life cycle GHG emission estimates publicly available?

Yes—the methodology, assumptions and inputs we used are detailed in the appendix of the report. The report is publicly available at **http://www2.cera.com/oilsandsdialogue**. We based our calculation of life-cycle GHG emissions on the results of 13 publicly available studies from government, academia, and industry sources. Our calculations show that the well-to wheel life-cycle GHG emissions from refined products derived wholly from oil sands are 5 to 15 percent higher than the average crude oil consumed in the United States. Some other estimates assert that the GHG intensity of oil sands is many times higher than conventional crudes. Several factors account for these differences, including that some assessments are based on comparisons of GHG emissions from only part of the lifecycle—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.

Emissions estimates varied greatly across the studies we examined. Differences among the individual 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.

The International Energy Agency (IEA), which includes the United States and 27 other OECD countries, recently released its own analysis of the life-cycle GHG emission of oil sands products, in the World Energy Outlook 2010. IEA came to a similar conclusion, that on average, products derived from Canadian oil sands have well-to-wheel GHG emissions that are 5 to 15 percent greater than most other sources of crude oil.

## Do the estimates of oil sands emissions include other fuel sources? Or are the estimates for products solely derived from oil sands?

Our 5 to 15 percent estimate is for refined products derived wholly from oil sands. We also estimated the life-cycle emissions for the average oil sands product imported to the United States. The most common oil sands imports are synthetic crude oil and diluted bitumen. Bitumen is diluted with natural gas condensates s that allows it to be pumped through a pipeline. Condensates generally have lower life-cycle GHG emissions than crude oil.

The average oil sands product imported into the United States (a mix of synthetic crude oil and bitumen diluted with condensates) has life-cycle GHG emissions 6 percent higher than the average crude oil consumed in the United States. Comparing what is actually imported and consumed is an appropriate measure when considering the impact of oil sands imports on US GHG emissions. When looking at other questions, such as the incremental emissions from growing oil sands supply, it is appropriate to look at the emissions from wholly derived products—this is the 5 to 15 percent range cited earlier.

## Why did IHS CERA report the emissions per barrel of refined products rather than per barrel of a specific product, like gasoline?

Each barrel of crude oil is converted into many refined products. When comparing the GHG emissions from different sources of crude, it is relevant to analyze the emissions resulting from all the refined products produced — not just one product. Additionally, allocating emissions across various refined products is a key challenge in life-cycle analysis. Including emissions from all products removes this potential source of error and confusion.

For steam-assisted gravity drainage (SAGD) projects, do the IHS CERA GHG emission values reflect the average for the industry?

The steam oil ratio - the amount of steam used for each barrel of production is a crucial metric for SAGD energy use and GHG emissions. The steam-oil ratio for each project is reported publicly. The weighted average (by production) of the steam-oil ratios for the 12 operating SAGD sites in the first half of 2010 was 3. This is value used in the CERA analysis.

## Do the GHG emissions in the IHS CERA report reflect direct land use change?

Our estimate of life-cycle GHG emissions does not include emissions from land use change, nor do any of the 13 studies that we considered in our analysis. When estimating the life-cycle GHG emissions for petroleum, the system boundary is generally drawn tightly around the production facilities, the refinery, and final combustion. Emissions beyond the facility gate are generally not included, nor are indirect emissions.

The omission of land use change emissions is a characteristic of today's life-cycle analyses. In our search of literature, we found only three studies that estimate the emissions from land use change in oil sands development and the results in these studies varied widely. Applying the data available, including land use change emissions would increase GHG emissions for oil sands products produced from mining and upgrading, but the emissions are still within the 15 percent range cited earlier. For in-situ developments, including land use change emissions does not result in a material change.

## Does the IHS CERA GHG emissions report reflect venting and flaring and fugitive emissions?

Yes, the IHS CERA study does include venting, flaring, and fugitive emissions.

## Does the IHS CERA GHG emissions estimate include emissions from the production of natural gas consumed by oil sands operations? What about GHG emissions from electricity generated outside the oil sands facility?

GHG emissions that occur outside of oil sands facilities are generally not included in life-cycle analyses. Therefore, emissions from the natural gas production facilities that supply gas to the oil sands industry are not included, nor are those from off-site electricity production. However, the majority of oil sands projects generate their own electricity at on-site cogeneration plants. The emissions from onsite power generation are included in the IHS CERA analysis, so the omission of off-site power generation is generally not material.

## For additional information regarding IHS CERA Canadian Oil Sands Dialogue contact

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# Assessing Environmental Regulation in the Canadian Oil Sands

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## About This Report

**Purpose.** This IHS CERA report assesses the environmental regulation system in the oil sands. How does the regulatory system in the Canadian oil sands compare with those of other jurisdictions? Are project approvals, ongoing monitoring, and final project reclamation requirements comparable? What are the similarities and differences?

**Context.** This is the second in a series of reports from the IHS CERA Canadian Oil Sands Energy Dialogue 2011. 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. The 2011 Dialogue program and associated reports cover three oil sands topics:

- **Major Sources of US Oil Supply: The Challenge of Comparisons**
- **Assessing Environmental Regulation in the Canadian Oil Sands**
- **Life-cycle Greenhouse Gas Emissions Reexamined**

These reports and past Oil Sands Dialogue reports can be downloaded at www2.cera.com\oilsandsdialogue.

**Methodology.** This report includes multistakeholder input from a focus group meeting held in Calgary, Alberta, on June 28, 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 end of report for list of participants and IHS CERA team).

**Structure.** After the introduction, the report has three parts followed by a conclusion and an appendix.

- **Introduction**
- **Part I—**The Project Approval Process
- **Part II—**Ongoing Operations
- **Part III—**Project Closure
- **Conclusion**
- **Appendix—**Website Links to Data Sources

We welcome your feedback regarding this IHS CERA report. Please feel free to e-mail us at info@ihscera.com and reference the title of this report in your message. For clients with access to IHSCERA.com, the following features related to this report may be available online: downloadable data (excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

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# ASSESSING ENVIRONMENTAL REGULATION IN THE CANADIAN OIL SANDS

## KEY IMPLICATIONS

The environmental regulatory system in the Canadian oil sands has been depicted as "weak" by its critics and "stringent" by its supporters. Comparing the oil sands environmental regulatory system with those in South Australia and Alaska demonstrates that, for the cases considered, there are many more similarities than differences:

- **Project-level regulation in the Canadian oil sands is generally similar to its peers, considering the procedures, data requirements, and measures to protect the environment.** The project approval, ongoing operations, and project closure phases of a project's life—including the data required and process—are similar across all three jurisdictions.

- **Data availability and transparency for oil sands are comparable, if not superior, to others when considering project approvals, reclamation financial security, enforcement, and inspections.**

- **There are differences in process sequence.** For Canadian oil sands, lands are leased to industry for the purpose of oil or resource extraction prior to studying the environmental impacts or consulting the public. In Alaska, the process proceeds in the opposite order.

- **Some oil sands reports are not digitized.** For South Australia and Alaska mining, since detailed environmental reports can be accessed online, the public can more easily monitor the activities of industry. For oil sands, since these reports are not online, it is more difficult for the public to scrutinize operations.

- **Financial security differs.** For surface mining, in case operators go bankrupt and cannot reclaim their disturbed lands, all regulators require financial securities. For the oil sands, the method differs from that of South Australia and Alaska.

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IHS CERA

# ASSESSING ENVIRONMENTAL REGULATION IN THE CANADIAN OIL SANDS

## SUMMARY OF KEY INSIGHTS FROM IHS CERA'S ANALYSIS

The environmental regulatory system in the Canadian oil sands has been depicted as "weak" by its critics and "stringent" by its supporters. To understand the rigor of the regulatory system, first an appropriate peer group must be identified. A screening process identified South Australian mining and Alaskan mining and oil operations as suitable peers for oil sands—their operations are of similar size and scope, and they have comparable governance, resource investment, and development philosophies. Comparing the oil sands environmental regulatory system to South Australia's and Alaska's demonstrates that, for the cases considered, there are many more similarities than differences.

**Project-level regulation in the Canadian oil sands is generally similar to the peers in this report, considering the procedures, data requirements, and measures to protect the environment.** The project approval, ongoing operations, and project closure phases of a project's life—including the data required and process—are similar across all three jurisdictions. Similarities include the approval process, public consultation and outcomes during approvals, the use of inspections and enforcement, and requirements for environmental monitoring. Although it is too early to fully assess the success of oil sands mine closure regulations—since oil sands mines have yet to be closed—the system is currently being strengthened to provide more specific mine closure performance metrics that are similar to those of the other jurisdictions.

**Data availability and transparency for oil sands are comparable, if not superior, to others when considering project approvals, reclamation financial security, enforcement, and inspections.** For all three jurisdictions, information supporting the project approval process—including environmental impact assessment reports, public comments, and operator's responses to these comments— is readily available. Considering the transparency of inspections and enforcement activities, oil sands data availability ranges from comparable to superior to others. For reclamation financial securities, oil sands regulators provide information on both the funds reserved and the lands disturbed by operations, a level of information that is comparable to Alaska and better than South Australia.

**Although there are many similarities, there are also differences. For Canadian oil sands, lands are leased to industry for the purpose of oil or resource extraction prior to studying the environmental impacts or consulting the public. In Alaska, the process proceeds in the opposite order.** In Alaska, before a major area is opened up to oil and gas or mineral extraction, an environmental impact assessment is conducted, and stakeholders are consulted. Only after the decision is made to approve resource extraction are lands awarded to resource developers—with stipulations and conditions for the region as a whole. With oil sands, however, only *after* the lands are awarded to developers for oil extraction are the environmental impacts of the proposed development studied and communicated to the public. Over the past decade, as the number of oil sands projects increased, questions were raised about the impacts of the development on the region as a whole. For instance, would biodiversity be sufficiently protected? Would water supplies meet growing demands?

To address these regional issues, Alberta is in the process of establishing a regional plan that encompasses the oil sands development area. If approved, the plan aims to establish regional environmental limits to manage the cumulative effects of development—setting regional thresholds for water, air, biodiversity, and land. In the future, all development in the region (including oil sands projects) will need to stay within these limits. Consequently, under the proposed plan, oil sands projects, similar to projects in Alaska, would have regional stipulations and conditions.

**For South Australia and Alaska mining, since detailed environmental reports can be accessed online, the public can more easily monitor industry activities.** For oil sands, since these reports are not online, it is more difficult for the public to scrutinize operations. The recently launched Oil Sands Information Portal (OSIP) provides one window for the public to view key oil sands metrics (for instance, regional and project-level metrics for water, land, greenhouse gas [GHG] emissions, and tailings ponds), but not all monitoring information is online. For instance, oil sands operators regularly submit environmental monitoring reports (totaling hundreds of pages) to the regulators. These types of reports are available online for Alaska mining and South Australia projects, but they are not online for oil sands. However, the public can obtain these operator reports through an information request or, for mining projects, at the Government Library. These detailed oil sands monitoring reports are not digital, and consequently often an inquirer must visit Edmonton, Alberta, to actually view the reports.

**Although active mines in Alaska and South Australia have formal requirements for frequent public consultation during operations, their oil and gas developments have no formal requirements.** For the oil sands industry, during the operational phase of a project, the regulatory system also has no formal requirement for regular consultation. Even when there is no formal requirement, in all three jurisdictions, many operators consult voluntarily with local stakeholders on a regular basis. The amount of information provided to stakeholders has increased over time, as companies are responding to growing demands for information.

**For surface mining, in case operators go bankrupt and cannot reclaim their disturbed lands, all regulators require financial securities.** For the oil sands, the method differs from the peer group. For Alaska and South Australia, the financial securities are intended to cover all estimated reclamation costs, whereas in oil sands, only part of the reclamation cost is paid by the funds in the government's financial security; the remainder of the cost is covered by the value of the resource (which in this case is bitumen). Only when the project starts nearing the end of its life (defined as when 15 years of reserves remain) are more funds required from the operator.

# INTRODUCTION: ASSESSING ENVIRONMENTAL REGULATION IN THE CANADIAN OIL SANDS

## REGULATION OF RESOURCE DEVELOPMENT

Oil supply from the Canadian oil sands has come under scrutiny on various fronts. One issue is the comprehensiveness of environmental regulation in oil sands development. The purpose of this IHS CERA report is to consider how the environmental regulation system in the oil sands compares with those of other jurisdictions. Are project approvals, ongoing monitoring, and final project reclamation requirements comparable? What are the similarities and differences?

In developing oil and gas or mineral resources, government regulation aims to account for the needs of a wide group of stakeholders. For instance, the owners of the resource (whether government or individuals) require financial gain in exchange for efficient and responsible exploitation of their resources. Others, especially those directly affected by the project, need to understand both the positive and negative impacts that could arise from the development and to be assured that the regulator is protecting their interests.

Within this broader context, the primary goal of environmental regulation is to minimize the adverse effects, to manage the risks associated with resource development, and to inform stakeholders by providing information about these effects and risks.

## FINDING PEERS FOR CANADIAN OIL SANDS: SOUTH AUSTRALIA AND ALASKA

To compare regulation in the Canadian oil sands to others, an appropriate peer group with high regulatory standards must first be identified. The peer group is an important consideration; without a peer group, one could set unreasonable standards for comparison and therefore make an inaccurate assessment. Ideally, the regulators should be similar—quasi independent, with projects of similar size and scope to those in the oil sands (see the box "Oil Sands Primer") and with comparable resource investment and development philosophies.

The independence of regulators varies considerably across the globe. For the oil sands, energy regulation is the responsibility of government agencies that, by design, have checks and balances among them to protect the public. The primary regulator for the Canadian oil sands is the Province of Alberta—with regulatory authority over resources, environment, First Nations consultation (related to resource development), and surface disturbance.[1]

The Canadian federal government also has jurisdiction over, and primary regulatory responsibilities for, among others, fish and fish habitat, changes to the navigation of waterways, and migratory birds and endangered species.[2]

1. In 1930, when the natural resources in Alberta were transferred from the federal government to the provincial government, the obligation to consult with First Nations groups under Treaty 8 fell to the province as well. The federal and provincial government must both consult with Aboriginal communities where they "contemplate crown conduct" that could have an impact or infringe on asserted rights.
2. Other federal responsibilities include to assess the impacts of proposed projects and to monitor and regulate pollutants—including toxic substances, air pollutants, and GHGs.

The approach to investment and development also influences the style of regulation. Jurisdictions like Alberta and Canada that are open to investment by independent companies generally provide transparent resource regulation. Countries that place more limits on who can develop resources generally provide less publicly available data, and this makes regulatory comparisons difficult.

The following criteria were used to identify a peer group for oil sands:

- **Developed countries, defined by membership in the OECD**. The OECD requires member countries to have an advanced regulatory system that is transparent and inclusive.

- **Jurisdictions with sizable volumes of land-based oil production (more than 0.5 million barrels per day [mbd]) and/or have an established mining industry.** Although Norway and the United Kingdom are large OECD oil producers, their oil is produced offshore. Many offshore regulatory requirements are not comparable with those in the oil sands.

- **Countries open to independent investment for resource development.** Mexico is a large OECD oil producer, but the state-owned oil company is the sole producer, and thus Mexico currently does not have sufficient transparency in its regulatory system to support a comparison to oil sands.

Using these criteria, Canadian oil sands peers include the United States and Australia. In Australia and the United States, similar to Alberta, the state or province typically leads the regulation of resource development. Therefore, states with comparable operations to Alberta must be identified.

Since oil sands are extracted through two means, surface mining and wells, the size of the mining and oil sectors in each jurisdiction is pertinent (see the box “Oil Sands Primer”). Table 1 highlights the relative size of the mining and the oil industries for South Australia, Alaska, and Alberta. Alberta is the only jurisdiction that extracts oil from surface mining, so the economic value of the total annual production between the mining industry for South Australia and Alaska (all resources extracted) is compared with that of the oil sands.

Alaska both produces oil and mines minerals. By quantity, some of the top minerals mined are lead, zinc, and coal. In Alaska, both the conventional oil and the mining industries are sizable—each has individual projects comparable in size to oil sands projects. South Australia’s oil industry is small compared with that of Alaska and Alberta; therefore, in this report, Alberta regulations are compared mostly with South Australian mining projects. In South Australia, by quantity some of the top minerals mined are iron ore, coal, and copper.

## ALASKA AND SOUTH AUSTRALIA ARE “PROJECT-LEVEL” PEERS

Although only part of the oil sands region will be developed at any one time, in aggregate about 21% of the total area of Alberta is leased for eventual oil sands development (18% for in-situ development and 3% for surface mining). The oil sands total area is about 55,000 miles square, or similar to the size of the state of New York. To date, land disturbed by surface mining is about 250 square miles, or about half the size of the central city of Houston,

**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—enough oil to solely supply 25 years of US oil demand.*

The oil sands are grains of sand covered with water, bitumen, and clay. The oil in the oil sands is called bitumen, 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.

Oil sands are unique in that the vast majority is produced via both surface mining and in-situ thermal processes.

- **Mining.** About 20% of currently recoverable oil sands reserves lies close enough to the surface to be mined. After the sand is dug out, it is transported by truck and sometimes by pipeline to a processing facility. Slightly less than half of today's production is from mining, and we expect this proportion to be roughly steady through 2030.
- **In-situ thermal processes.** About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling wells. After steam is injected into the wells, oil flows to the surface through the production wells. Such methods are used in oil fields around the world to recover very heavy oil. Two thermal processes are in wide use in the oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation. In-situ thermal makes up about 35% of 2010 oil sands production and is expected to grow to more than 45% of oil sands production by 2030. Thermal recovery methods have reduced the amount of energy needed to recover bitumen, and such innovations are likely to continue in the future.
- The remaining oil sands production is extracted without steam or mining using conventional heavy oil cold-flow methods.

*Assumes average US petroleum demand over the next 25 years (excluding biofuels) is 18 mbd.
Source: IHS CERA.

**Table 1**

**Size of Mining and Oil Sectors: Oil Sands, Alaska, and South Australia**

| | 2010 Oil Production (bd) | 2010 Mining Commodity Values (US dollars per year) |
|---|---|---|
| Canadian oil sands | 750,000 (production from wells)[1] | $23 billion (production from surface mining)[2] |
| Alaska | 647,000[3] | $3.1 billion[4] |
| South Australia | 16,000[5] | $3.6 billion[6] |

Source: IHS CERA.
1. Alberta Energy Resources Conservation Board (ERCB), *Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011–2020,* June 2010. Note: combined volume of in-situ (CSS and SAGD) and primary bitumen production.
2. Ibid. Value of SCO production at Alberta bitumen reference price, and average 2010 exchange rate used is 1.03 US dollar/Canadian dollar.
3. Alaska Department of Natural Resources (DNR) Division of Oil and Gas, Annual Gross Production Off State Lands, 2010. http://dog.dnr.alaska.gov/Royalty/Production.htm.
4. DNR, 2010 Alaska's Mineral Industry, 2010. Note: includes all mined resources, such as gold, silver, coal, tin, peat, rock, jade, soapstone, and ceramics.
5. Primary Industries and Resources South Australia (PIRSA), *MESA Journal,* March 2011, Volume 60. Note: includes both crude oil and condensate production.
6. Ibid. Note: includes all mined resources, such as opal, copper, iron ore, gold, and uranium oxide, and average 2010 exchange rate used is 1.09 US dollar/Australian dollar.

Texas. Oil production could grow from 1.5 mbd currently to between 3.0 mbd (moderate growth case) to 6.3 mbd (stretch growth case) by 2035.[1] Because of the potential scale, geographic reach, and undeveloped state of much of the land already leased for oil sands development, there are concerns about the cumulative impacts of this scale of development. To prepare for the projected growth in oil sands, initiatives are under way. For instance, the Cumulative Environment Management Association (CEMA) studies the environmental effects from development as a whole, and regional air and water monitoring systems are in place and are being further strengthened. These types of regional initiatives, at the scale of oil sands, were not observed in the other two jurisdictions. However, comparatively, the projected growth of the mining and oil and gas sectors of South Australia and Alaska are relatively small; consequently, although the project-level regulatory systems are generally comparable, the regional regulatory, planning, and monitoring requirements are not necessarily comparable (given the different growth trajectories). For that reason, in most cases this report focuses on the project-level requirements.

## COMPARING ENVIRONMENTAL REGULATION IN OIL SANDS

The remainder of this report is in three parts, followed by a conclusion. The three parts compare how the regulatory system manages and communicates risk throughout three stages of an individual project's life cycle: approval, the ongoing operations, and the final closure of the project. To be sure, this report is not a comprehensive list of all aspects of oil and gas regulation; rather, it serves as an illustrative case study to evaluate some specific examples.

- Part I—Project Approval Process
- Part II—Ongoing Operations
- Part III—Project Closure
- Conclusion

The appendix provides data sources and website links that support this analysis.

1. See the IHS CERA Special Report *Growth in the Canadian Oil Sands: Finding the New Balance.*

## PART I: PROJECT APPROVAL PROCESS

An objective of the project approval process is to inform decision makers and stakeholders about the proposed operation—including the benefits, potential adverse environmental impacts, and risks. For a brief description of Alberta, Alaska, and South Australia's project approval process, see Table 2 and the box "Comparing Project Approval Processes."

Among Alberta, Alaska, and South Australia, many features of the approval process are similar. Project-specific data requirements are similar. All involve a multiyear process that

**Table 2**

**Key Metrics: Comparing Project Approval Processes**

| | Alberta | Alaska | South Australia |
|---|---|---|---|
| Approval process for large projects | Project-level approval after lands are leased | For larger, multiproject developments, first step requires regional environmental assessment/approval; next step is leasing lands, and final step is specific project-level approval process | Project-level approval after lands are leased |
| Data to support application | Topics covered are similar to others; initial application report (EIA) in the range of 1,800 to 4,000 pages of text | Topics covered are similar to others; federal application report (Environmental Impact Statement [EIS]) in the range of 1,200 to 2,000 pages of text or more | Topics covered are similar to others; major projects application report (EIS) over 2,000 pages of text |
| Timeline for project approval | Three to six years, depending on complexity, opposition, and/or federal involvement | For development fitting within a previous regional assessment/ approval, typically between 12 to 18 months but can be as long as three years | Recent major mining project took six years |
| Public consultation requirements | Written comments, plus some projects have formal hearings—like court proceedings, often span two weeks | Written comments, plus some projects have "town hall" style meetings | For major projects, written comment and "town hall" style meetings |
| Data availability | Readily available on Internet | Readily available on Internet | Readily available on Internet |

Source: IHS CERA.

comprehensively documents the project, its potential risks, and plans to mitigate these risks. Also, all three jurisdictions ensure that the public can comment on the planned project and that data and documents regarding the project are readily available to the public.

## Public Consultation: Some Differences in Process

There are some differences in the public input process. In South Australia, depending on the scope of the project, formal consultation is not always required, whereas generally the Alaskan approval process provides for public comments. For both jurisdictions, the comments can be written, or they may be provided at open "town hall" style meetings in affected communities; typically, the meetings are less than one day. Anyone can comment—even individuals not from the community or even the country.

Similarly, in Alberta, public comments are open to anyone and can be provided in writing to the regulator and project developer. When a concern is raised that cannot be resolved through dialogue with the developer, or if the regulator requests, a formal hearing can be initiated. The hearing meetings can span a few weeks or more and are similar to court proceedings. For Alberta-only applications (as opposed to joint federal/provincial applications) to trigger a formal hearing, the individual or group must prove that it is directly affected by the project. However, once a hearing has been triggered, hearing proceedings are open to anyone—as in Alaska and South Australia.

When considering the effectiveness of public consultation, it's important to consider whether the efforts result or can result in any material changes to projects. In Alberta, South Australia, and Alaska, project approvals are typically subject to numerous conditions that are a direct outcome of stakeholder input. For instance,

- In Alaska, responding to public concerns, the True North mine had to build an expensive highway crossing and add light and noise provisions to address public, safety, and agency concerns.[1]
- ConocoPhillips Alaska "CD5 Drillsite Development" project was redesigned in response to the North Slope Borough and native residents. However, despite these changes, the project was still denied approval at the federal level. After a year of appeals and negotiations, ConocoPhillips won the appeal with additional conditions for development.
- In the Alberta oil sands, Suncor Energy's approval for a mine extension and upgrader had seven conditions. One condition required Suncor to speed up tailings pond reclamation. Another required a change in the mine plan to protect a wildlife corridor. Suncor agreed to meet all conditions.[2]

1. Source: Alaska Department of Natural Resources (DNR) and University of Alaska Fairbanks Cooperative Extension.
2. *Big Reserves, Big Responsibility—Developing Alberta's Oil Sands,* Alberta Energy Resources Conservation Board (ERCB), March 2011.

- In South Australia, the recent approval for the Olympic Dam, a copper and uranium mine, had more than 100 conditions. One condition requires the developer to create an offset area of 140,000 hectares to conserve biodiversity.[1]

It is important to note that although all jurisdictions have numerous examples in which public concerns result in material changes to a proposed project, this is not always the case. Public concerns are not always addressed in project approvals. Sometimes the potential alternative is deemed cost prohibitive or the best available alternative is deemed to create new, equally adverse consequences.

### What Is First: Approval or Land Sale?

In the Alberta oil sands, lands are leased to industry for the purpose of oil or resource extraction prior to initiating the project approval process. The Alberta system differs from Alaska in this respect. In Alaska, for a substantial development, one that includes multiple projects, before a major area is opened up to resource extraction, the public is notified, and an environmental assessment of the impacts for the region as a whole must be approved, including effects on habitat of fish and wildlife and foreseeable cumulative effects.[2] Only after the decision is made to approve resource extraction are lands awarded to resource developers in a lease sale. The lease sale offering is made to operators with full knowledge of all stipulations and conditions associated with the approval for the region as a whole. For Alaska, because the overarching development has already been subject to the previous regional environmental assessment (prior to the lease sale), each individual project fitting under this umbrella may have a shorter review period. This regional assessment approach is typically used only for larger-scale developments or when projects are subject to federal rules. Recently, this approach was used for a new oil and gas development—about one-fifth the area of oil sands.[3]

This required regional environmental impact assessment (to set environmental goals for the area as a whole) prior to deciding to develop the resource is a significant difference between Alaska and Alberta. As demonstrated by our research, Alberta oil sands developments go through a comprehensive project-specific approval process and evaluation. But as the scale of development and the number of projects have increased dramatically, concerns about the cumulative impact of development on the region as a whole have emerged. To address this issue, the province of Alberta is now introducing a regional plan for the oil sands, called the Lower Athabasca Regional Plan (LARP). The draft plan, released in August 2011, considers the potential regional impacts under different oil sands growth scenarios. If approved by government, the plan will create new conservation areas and set regional environmental limits for air, water, land, and biodiversity for the oil sands (see the conclusion of this report for more information on LARP). Under the proposed plan, oil sands projects, similar to projects in Alaska, would be subject to regional stipulations and conditions.

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1. See more information on the Olympic Dam copper and uranium mine October 2011 approval: http://www.environment.gov.au/minister/burke/2011/mr20111010.html.
2. Typically, for federal lands this is a National Environmental Policy Act (NEPA) Environmental Impact Analysis (EIA), or for state lands a Best Interest Finding (BIF).
3. The BIF for the North Slope Foothills area covered 7.7 million acres; the oil sands covers 55,000 square miles, or over 35 million acres.

What comes first, the land sale or the regional environmental assessment, is a factor shaping the timeline for project approval. In Alberta and Australia, a "significant impact" project can take up to six years between initiating the project application and finally receiving approval. For Alaska, for a project that falls under a previous regional approval, the process for a new approval is usually shorter, approximately 12–18 months, but legal suits on more controversial projects can even out the timelines. In Alaska, a legal challenge with multiple appeals can add two or more years to the regulatory timeline. In South Australia, following a decision on a major project, there are no appeal rights with the regulatory agency. In Alberta, appeals to the regulatory agency are rare and appeal rights are limited. However, for both Alberta and Australia, legal complaints on regulatory decisions can still be filed with the courts, and in Alberta, disputes can also be reviewed by the Environmental Appeals Board.

## Rubber Stamp Approvals?

One criticism of oil sands is that projects are always approved. To date, no commercial-scale oil sands project has been denied approval. Comparatively, looking at major projects from South Australia, of the 29 projects assessed since 2003 (ranging from major mining projects to installing new lighting at a stadium), just two projects were refused. For Alaska over the past 10 years, only one federal project has been denied approval, and the appeal for this case is pending.[1] For all jurisdictions, one reason for few project denials is that during the approval process, if a project developer discovers that it cannot meet the requirements, it generally terminates the costly application process or changes the project design to meet the alternative approach preferred by the regulator. These changes can increase project costs and/or delay the timeline. For Alberta, Alaska, and South Australia, although most projects that do successfully navigate the process are approved, they are not "rubber stamped."

For Alberta, because the government leased oil sands lands to developers for the purpose of oil extraction *prior* to the regional environmental assessment and study of overall cumulative impacts (see What Is First: Approval or Land Sale? above), if the project meets the project-level requirements of the regulators and addresses affected stakeholders concerns, an approval should be expected. However, this system is now being adjusted. Assuming the proposed regional plan or LARP system is approved, future project approvals will consider regional environmental thresholds in addition to project-level requirements. As a result, in upcoming approvals, if development of a project would result in exceeding regional limits for land, air, water, or wildlife (based on evaluations of the status of environmental conditions), it would not be approved—or probably never even applied for.

1. This excludes wetland jurisdictions.

## Comparing Project Approval Processes

### *Alberta*

**Process.** To obtain approval for an oil sands development, the project developer (termed proponent) is subject to the provincial Environmental Assessment (referred to as an EA) process (under the Environmental Assessment Regulation, Mandatory and Exempted Activities, which lists activities that must undergo EIAs in Alberta).* In addition, if a federal "trigger" such as a fish compensation plan or authorization to cross a navigable waterway is required, a joint federal/provincial EIA is initiated. A federal/provincial review panel is appointed to review and assess the project, and the Canadian Environmental Assessment Agency (CEAA) is the lead federal regulator in the project application process.

The EA is the first step of the provincial regulatory process. First, the proponent issues a "proposed terms of reference" and a "project summary table." These documents provide high-level information on the project and information to be included within the EA report. If required, proponents also provide a First Nations Consultation Plan. After an open comment period, the Environmental Assessment Director issues the "final terms of reference." The next step is delivering the substantial amount of documentation required for the integrated application, which includes the EIA report and applications for approval (those required by the Alberta Ministry of Environment and Water and the ERCB).

Alberta Environment and Water and associated government agencies undertake a technical review of the EIA report to ensure the information meets the requirements set out in the final Terms of Reference for the Project. After this review, a determination is made on whether the EIA report is complete. The determination of EIA completeness does not represent acceptance or approval of the proposed project. The EIA report is then referred to the ERCB, which issues a decision on whether the project may continue the regulatory process. If the ERCB approves the project, the project application still requires a regulatory decision by Alberta Environment and Water under the Environmental Protection and Enhancement Act and Water Act. Sustainable Resource Development must also render a decision on the application under the Public Lands Act.

In Alberta, during the regulatory process, project proponents address comments from the public. Anyone can submit comments during the proposed terms of reference comment period. In a province-only approval process, either a "directly affected" stakeholder or the regulator can also trigger a public hearing; at the hearing, anyone can comment on the project. In a joint federal/provincial review, the regulators determine whether a public hearing is required. In a hearing under a joint review, just like in the provincial hearing, anyone can comment. Not all oil sands projects have public hearings.

If held, formal hearings allow regulators and the public to present their concerns and project developers to address them. These hearings are formal quasi-judicial proceedings, similar to court proceedings, and can span many days—a recent oil sand mine hearing lasted nine days. Following the hearing and responses to the concerns raised, a formal decision to approve or deny the project is issued. The complete process can take from two to six years depending on complexity, opposition, and/or federal involvement.

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*Small in-situ projects (normally pilots) under 12,500 bd are considered discretionary activities, where Environmental Assessment Director determines whether an EA is required. If an EA is not required, the project has a shorter regulatory process.

**Comparing Project Approval Processes (continued)**

**Data required.** The integrated application document (which includes the EIA report and associated applications) for a typical oil sands mine is 10-plus volumes of text with over 4,000 pages. The report is a comprehensive overview of the project. The information provided includes plans for public consultation; health and safety requirements; economic benefits; animal and potential human health effects; impacts to water (including surface water and groundwater technical analysis), vegetation, and soil and analysis of numerous potential environmental impacts; traditional land use assessment; reclamation plans; and baseline environmental data. The integrated application also includes an assessment of the cumulative effects of the planned and approved projects on the environment near or downstream of the proposed project—including water, soil, air, and potential health effects. In addition to the EIA and approval application documentation, the application includes numerous other documents related to the project, including comments from affected stakeholders and the project developer's response to the comments.

For typical in-situ oil sands projects (which are smaller than mining projects), the integrated application is about six volumes of text, with over 1,200 pages. The EIA report comprehensively covers all aspects of the project, similar to the subjects covered within the mining application (see the appendix of this report for the website link to the Alberta Environmental Protection and Enhancement Act, which outlines the contents of an EIA report and approval application).

**Data availability.** All documents related to the application are posted online by the ERCB during the decision process. For a joint federal/provincial approval, the documents are also available online at the CEAA website. In addition, all approvals can be accessed online at the newly created OSIP (see the appendix of this report for website links to the approval documents).

***Alaska***

**Process.** The state-level environmental approval process in Alaska is decentralized. A major development project requires multiple approvals and permits from federal, state, and borough/local authorities. The specific approval process for each project is unique, depending on the project scope, the impacts, and whether the land is owned by state, federal, borough, or native authorities.

If the project falls within federal jurisdiction, a NEPA process is required. To determine the level of NEPA analysis required, a federal agency must first assess the project's impacts. There are three levels of NEPA; if the impacts are low, the proposed activity can be excluded from NEPA analysis. The second level is the environmental assessment (also known in this process as the EA) to determine whether a project would significantly affect the environment. The third level—reserved for projects with significant environmental impact—is the EIA. Most often, numerous federal agencies have jurisdiction over a project; therefore, one lead agency is assigned responsibility for conducting the NEPA analysis on behalf of all agencies. In some cases, an agency will begin a project with the less-detailed EA, and through its analysis determine that the potential impacts are significant, requiring the detailed EIA.

A project that only requires permits from the State of Alaska does not go through the NEPA process. However, state agencies still assess the impacts of the proposed project. For example, before a significant multiproject development (one that approaches the scope and geographic reach of oil sands) is approved for resource extraction, the regulator must first determine in a written finding that the activity is in the state's best interest—termed the BIF. The BIF discusses the potential cumulative regional environmental impacts from the activity—including foreseeable effects on the area's fish and wildlife, historical and cultural resources, and communities. The report is prepared for public review and comment. Sometimes the federal authorities cooperate

## Comparing Project Approval Processes (continued)

with the state agencies on a BIF. However, for smaller projects in the state, such as an individual mine, an alternative approach is used—here the environmental assessment is made at the project level only, similar to Alberta.

For an onshore oil and gas development, the permitting and siting can involve as many as 20 regulatory stakeholders, each with unique requirements. Alaska does not have a formal comprehensive public consultation policy. However, most state permits require a public comment period and many allow for public hearings. Permitting agencies typically allow a 30-day comment window for the public to register concerns, which regulators can extend if public interest warrants it. In addition, project developers are encouraged to consult with the public early in the process and to show previous consultation efforts in their permit applications.

For the federal NEPA process, if the project is determined to have a significant environmental impact, a Draft Environmental Impact Statement (DEIS) is issued. The lead regulator conducts public scoping meetings to identify issues that need to be addressed in the DEIS. Once the DEIS is prepared, it is presented for public review and comments, and additional public hearings or open houses are conducted in the affected communities. The meetings use either a "town hall meeting" format or a formal public hearing meeting that is open to anyone. Following this process, the final Environmental Impact Statement (EIS) is issued that includes a response to the public comments. If a federal agency conducts an EA in lieu of an EIS and determines the project would not significantly affect the environment, a Finding of No Significant Impact (FONSI) is issued. After public comments and consulting other agencies and regulators, the lead regulator issues a decision to approve or deny the project. The approval process for a significant development, one that requires both state and NEPA approvals, typically takes between 12 and 18 months but can be more than three years. If only the shorter EA is required, a project approval process can typically be completed in less than 10 months.* For smaller state projects, such as an individual mine, that do not fall under an existing regional approval, the timeline for an approval typically ranges between two and three years.

**Data required.** Since the NEPA process is typical for a project on the scale of oil sands, we look at NEPA data requirements here. The EIS for a significant mine or oil development project typically totals from 1,200 to 2,000 pages or more. However, documents referenced, such as baseline studies on many projects, can greatly increase this number. Examples of information typically provided in the EIS include the purpose and need for the project, a description of the affected environment (including the human environment), potential alternatives to the project, impacts to the environment—both direct and indirect and cumulative (with both the proposed project and alternatives), plans to mitigate and monitor adverse effects, reclamation requirements, other permits under application (state, federal, and local agencies), tribal and regional consultation plans, and public comments from both hearings, with written responses from the developer. In addition to the EIS materials, more documentation is required for various permits at the state, federal, and local levels and for compliance with other federal acts, such as the Endangered Species Act. The EIS also lists all public meetings held, identifies speakers, and includes the developer's responses to each concern raised (see the appendix for a website link to the regulations for implementing NEPA, which outline the contents of an EIS report).

**Data availability.** For NEPA approvals, the final EIS documents are posted online at the lead agency's website. In Alaska, they are also available at the agency's office, in libraries, and in other public places. Active mining projects have a comprehensive summary of permits online. For oil and gas developments, the permits for individual projects are not online but can be requested from each regulator (see the appendix for websites with approval documents).

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*Source: US Department of Energy, *NEPA Lessons Learned,* September 1, 2011, Issue No. 68, Third Quarter FY 2011.

## Comparing Project Approval Processes (continued)

### *South Australia*

**Process.** In South Australia, mines and oil and gas developments have separate processes. Mines go through a two-stage process—first obtaining a mining lease and second obtaining approval for a project's Program for Environmental Protection and Rehabilitation (PEPR).* The mining lease proposal identifies the project's risks and presents the likely outcomes of the project, and demonstrates the benefit to the public. The mining lease proposal includes the baseline environmental description, risks associated with the project, and details on vegetation clearing. For mining, the PEPR process requires that environmental outcomes are developed in consultation with landowners and any stakeholders at the mining lease assessment stage of the project approval.

Petroleum activities have another approval process, governed by the Petroleum and Geothermal Act 2000. Each land area in South Australia is governed by a Statement of Environmental Objectives (SEO) that includes regional environmental objectives and the criteria to measure the success or failure of projects in meeting these objectives. South Australia oil projects are much smaller in scale and environmental impacts than projects in Alberta and Alaska. Therefore, the SEO documentation is relatively less detailed.

Projects deemed "major projects"—those with similar scope to many oil sands projects—require a separate and more detailed assessment process, with multiple chances for the public to comment. First, the project must prepare an application, followed by an Environmental Impact Statement (also known as an EIS) that is made available for public comment. The project developer holds a series of public meetings in communities potentially affected by the development. The project developer must respond to comments raised by the public and government agencies in a written response or a supplemental EIS. The next step is a second round of comments on this response, followed by additional responses from the developer, before the government agencies render a decision to approve or deny the project. A recent approval for a copper and uranium mine (called the Olympic Dam)—estimated to eventually cost between AUS$20 and $30 billion, or about two to three times more than a typical oil sands mine—took six years.

**Data required.** For a major project, the EIS is typically over 2,000 pages. The EIS is a comprehensive summary of the project. Examples of information provided include the need for the project, potential alternatives to the project, impacts to the environment (from both the proposed project and alternatives), plans to mitigate and monitor effects, reclamation requirements, Aboriginal and nonaboriginal cultural heritage, consultation plans, social considerations, labor supply, health and safety, and public comments from both public meetings and written responses. The documentation also includes major public concerns—grouped into major issues/themes—and the developers' plans to mitigate these concerns (see the appendix for a website link to the Development Act 1993, which outlines the requirements for the major projects process and the EIS document).

**Data availability.** Information on major projects currently being assessed can be found online. Older documents related to approved resource developments can be searched using an online database called South Australian Resource Information Geoserver (SARIG). Documents supporting mine projects that do not fall into the major projects category can also be found on the SARIG database. Documents supporting the oil and gas approval process are found at the Primary Industries and Regions South Australia (PIRSA) Petroleum website. Also, if a document is not available to download directly from the database or website, it can be requested (see appendix for website links to SARIG database and PIRSA).

*The South Australia mining act was amended in July 2011; prior to this the approval was called Mining and Rehabilitation Program (MARP).

## PART II: ONGOING OPERATIONS

Regulatory regimes place considerable focus on the project approval process, although it represents a relatively small part of a project's life. Major resource developments are often operational for 30 years or more. The primary objective of regulators during ongoing operations is to ensure that operators comply with regulations.

To compare regulation during the operational phase for Alberta, Alaska, and the state of South Australia, the following activities are analyzed:

- Environmental monitoring
- Ongoing consultation
- Inspection and enforcement

### ENVIRONMENTAL MONITORING

Monitoring is required to check whether project outcomes and impacts are consistent with the project approval, with environmental protection standards, and with statutory obligations. Alberta, Alaska, and the state of South Australia all require operators to regularly submit environmental monitoring data.

Table 3 and the box "Comparing Project-level Environmental Monitoring" evaluate project-level monitoring requirements for air, water quality, and biodiversity. To be sure, the aspects considered are not a comprehensive list of all environmental attributes that should be monitored; rather, they serve as illustrative case studies to evaluate requirements across these regions.

Regulatory requirements for air, water quality, and biodiversity monitoring across the three locations are similar, and when specific requirements differ, most often project-level

**Table 3**

**Key Metrics: Project-Level Environmental Monitoring Processes**

| | Alberta | Alaska | South Australia |
|---|---|---|---|
| Air, water, and biodiversity monitoring requirements | Similar project-level requirements in all three locations | Similar project-level requirements in all three locations | Similar project-level requirements in all three locations |
| Data availability | Some project level environmental data online at OSIP; more detailed operator environmental reports at library or by request | Mining operations make detailed environmental reports available online. Some oil and gas data are online; most detailed information requires request | For both mining and oil and gas, detailed operator environmental reports are accessible though online database |

Source: IHS CERA.

requirements are not directly comparable. For instance, requirements for monitoring surface water in South Australia, where most oil and gas or mining operations are in desert areas, are different from those for the Alberta oil sands, a wetland region. Monitoring requirements also vary by the type of development; gold or zinc mines have different potential contaminants and monitoring needs from oil sands developments. Even within a jurisdiction, environmental thresholds for similar projects can vary. For Alaska, some areas within the state are designated as "protected" and consequently they have stricter environmental thresholds.[1]

## Overlapping Authority Can Create Conflict

For all three jurisdictions, overlapping authority between state and federal regulators or sometimes even among regulators within the same state or province can lead to conflict. Often, when the environmental impacts are transboundary (meaning that they cross borders), environmental limits and monitoring are subject to multiple authorities. For instance, pollutants made mobile in air or water can cross provincial or state boundaries. Biodiversity impacts can also cross borders. At times, this overlap in authority causes conflict, as the pollutants are subject to multiple regulatory agencies and rules.

In one example, the US federal government has listed beluga whales as an endangered species, and as a result some areas slated for oil and gas development in Alaska have become protected. Meanwhile, the State of Alaska (which is likely to lose oil and gas revenues from this decision) does not agree with the endangered status.

In South Australia, the federal Murray-Darling Basin Authority (MDBA) was established to protect an environmentally stressed water basin that spans five states and supports one-third of Australia's food supply.[2] With the formation of the MDBA, the federal government can override any state-level rules. In an effort to improve the river habitat, MDBA issued a draft plan to reduce water withdrawals by 27%–37%. With less water available for use, Australian states expect that they will suffer economic and social consequences, and they strongly oppose the plan.

The oil sands region also has overlapping jurisdiction between federal and provincial regulators. In one example, the federal government has jurisdiction over species at risk. If a species is considered endangered, the federal government can enact rules that override other activities in the region. Recently, environmental groups took the federal government to court over an overdue plan to protect and recover the oil sands region's caribou. The federal government—which currently lists these caribou as threatened under the Species at Risk Act—issued a draft plan two months later. In another example, authority for surface water overlaps between provincial and federal regulators. In the oil sands region, the Regional Aquatics Monitoring Program (RAMP) has been monitoring surface water since 1997. Over the years, the RAMP program had been criticized as being inadequate for detecting all changes in the watershed. In 2011, two independent studies were separately conducted by the federal and provincial governments, and both recommended development of a new

1. In Alaska, regions with stricter environmental thresholds for air because they do not meet national air quality standards are called nonattainment areas, whereas other areas such as national parks are protected under their class 1 area status.
2. Source: Australian government Murray-Darling Basin Authority.

oil sands regional monitoring system. The exact timing of the new system is uncertain, and plans are now being proposed. To date, regulatory authority overlaps have not created significant conflict for oil sands development, but the potential exists.

### Differences in Data Availability

Although the monitoring requirements across the three locations are similar, public access to project-level environmental monitoring information varies across the three jurisdictions—Alberta, Alaska, and South Australia.

Oil sands data are available through Alberta Environment and Water's OSIP: the website includes project-level metrics and data covering air quality, GHG emissions, production, water, and land. The OSIP also publishes regional data for biodiversity, water, and aggregate environmental metrics for oil sands (total land disturbed, total tailings area, total water use, etc.). These regional metrics are unique and not readily available in South Australia or Alaska.

Although the Alberta OSIP provides data and metrics, in comparison to Alaska mining and South Australia operations the detailed data are less available. For instance, in Alberta each operator regularly submits detailed environmental monitoring reports to the regulators. These reports can span hundreds of pages and provide detailed monitoring data for each site. Although such reports are available online for Alaska mining and South Australia projects, they are not online in Alberta, nor are they digital, but they are publicly available. For mining operations, the reports may be obtained through the Alberta Government Library system. For in-situ projects, the reports can be accessed via an information request to the regulator. Because they reports are not digitized, after making an information request, one must personally visit the regulator's office in Edmonton Alberta to view the information.

Although the detailed environmental monitoring data for oil sands are less readily available than for Alaska mining and South Australia, Alberta does make data more accessible than Alaska does for its oil and gas operations. For Alaska oil operations, some data (air permits, water quality, water injection, federal biodiversity, and log data) are readily available online, but other environmental data must be requested from the appropriate regulator. In addition to providing more online data, the Alberta OSIP provides one window to find information. In Alaska, the online data are distributed among the numerous regulators' websites and can be difficult to track down. Also, the complexity of Alaska's state and federal jurisdictions requires a good understanding of all authorities in order to know who to ask to obtain information pertaining to one issue or permit. It is easiest in South Australia, where one regulator manages and provides most project-level information.

## ONGOING CONSULTATION

During the project approval process, project operators in all jurisdictions undertake efforts to inform affected parties about the potential effects of the project. But after the project is built and operating, what requirements do the project operators have to keep impacted communities informed? Are a project's near-term plans and possible effects communicated to affected communities, and if so, how?

## Comparing Project-Level Environmental Monitoring

### *Alberta*

**Air.** Both oil sands mines and in-situ facilities are required to provide air quality reports to Alberta regulators. The reports include information from passive ambient air monitoring (including data on hydrogen sulfides [$H_2S$], sulfur dioxide [$SO_2$], nitrogen oxides [$NO_X$], methane, ozone, total suspended particles, and total hydrocarbons) and calculated total emissions of $SO_2$, $NO_2$, and fugitive emissions.* A number of facilities have continuous air monitoring installed, either on site or at a nearby regional station.** The oil sands region has 15 regional air monitoring stations providing online, real-time air monitoring data for pollutants (see appendix for website link to real-time oil sands regional air monitoring data). Each site classified as a large emitter must also report its GHG emissions. Air pollution can travel over provincial boundaries, and under the Canadian Environmental Protection Act, federal authorities monitor and make data available for air pollutants and GHGs as well as other pollutants.*** To date federal authorities have not enforced unique air regulations for oil sands. In the future, if the federal government were to regulate GHGs, it would be the first time the Canadian federal government exerted jurisdiction over air for oil sands.

**Water quality.** Projects that fall under the Navigable Waters Protection Act and projects that affect fish or fish habitat are under federal rules. Also, the federal government shares responsibility for water quality for transboundary waters (between provinces, territories, or federal-provincial crown lands). Therefore, both the federal and provincial governments have jurisdiction, and the Canada Water Act calls for joint consultation between federal and provincial authorities. For groundwater, typically the Alberta government is the lead authority, but federal authorities can also have jurisdiction if there is interaction with surface water.

To ensure that surface water and groundwater are not being adversely affected by operations, each oil sands facility monitors water level and quality in groundwater and surface water (streams, ponds, and lakes) around its site. Chemical analysis confirms conventional water quality parameters (such as total dissolved solids, pH, and hardness) and parameters indicative of pollution, such as dissolved metals, total metals, and dissolved hydrocarbons. Surface water is also tested for total suspended solids and biological changes (monitoring of fish and other species in the water). For oil sands sites that affect navigable water or fish habitat, both the provincial and federal authorities require monitoring reports.

**Biodiversity.** The federal government has developed a national biodiversity strategy in cooperation with the provinces and territories. A number of provinces and territories also have developed and implemented their own frameworks in accordance with the national guidance. The province is the lead regulator for most components of biodiversity. The exception is for migratory birds and national species at risk; here the federal government has certain responsibilities and can intervene if it is demonstrated that the province is not providing adequate protection.

For monitoring vegetation, each oil sands site is required to report infestations of harmful weeds and take all actions to mitigate their spread. Operators also report revegetation activities, such as progress to store native seeds and to reforest. Operators also conduct wildlife and bird monitoring, including documenting sightings and movements, and reporting activities to mitigate human interactions. All known wildlife and bird incidents are documented—including an itemized list of deaths and injuries.

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*Passive sampling gives indication of long-term values but is not sensitive enough to catch short-term peaks.
**Continuous sampling provides frequent measurements, capable of catching short-term peaks.
***Federal government is responsible for the National Pollutants Release Inventory (NPRI).

**Comparing Project-Level Environmental Monitoring (continued)**

**Data availability.** Production data, reports on tailings accumulations, and various operating data are online. Also regional and project-level environmental metrics are available through the OSIP. As for more detailed data, oil sands operators provide environmental data in various reports—conservation and reclamation, groundwater monitoring, soil management, and air quality monitoring. Report frequency varies by type—some are required monthly, quarterly, or annually. In addition, each mining project submits a comprehensive annual environmental report, totaling over 300 pages and consolidating the results of a number of reports into an annual review.

Although the more detailed operator environmental monitoring reports are public, the ease of accessing the data varies. The large annual mining reports can be found at the Alberta Government Library. Viewing in-situ reports requires an information request to the regulator. Information requests are common; currently, Alberta Environment and Water responds to between 25 and 75 information requests each week.

Although the detailed reports are available, the process is not always evident. For instance, it took a number of inquiries to learn that project-level annual mining environmental reports were at the library. Likewise, it took numerous inquiries to clarify the information request process needed to obtain the in-situ environmental reports. A further complication is the lack of digital reports, since viewing the documents requires a visit to the office or library, where they are located—often in Edmonton, Alberta.

Environment Canada also monitors and publishes pollutants in the NPRI (see appendix for website links to monitoring data).

***Alaska***

**Air.** As in Alberta, air quality in Alaska is regulated at both the state and federal levels. Although regulations typically follow the federal structure, the state's air quality program has some unique requirements for oil and gas developments. The air pollutants monitored are similar to those in Alberta—$H_2S$, $SO_2$, $NO_X$, methane, ozone, lead, total suspended particles, and total hydrocarbons.

All mines and oil production facilities require an air permit to construct and operate that governs the amount of contaminants each operation can emit. To comply with the permit, sites must monitor and report ambient and fugitive emissions, including any that exceed permit limits. For instance, a compressor station in Prudhoe Bay must continuously monitor air from exhaust stacks and estimate total carbon monoxide and $NO_X$ emissions. For mining sites, monitoring dust is a key concern, especially in protected areas.

Air standards and reporting requirements are not uniform for every location or site. For instance, when an area is already under environmental stress or when a site frequently exceeds permit thresholds (termed *nonattainment areas*), more strict environmental requirements are often established. Also, as of July 2011, the US Environmental Protection Agency (EPA) requires Alaskan operators to report their GHG emissions.

**Water quality.** For mining and oil and gas developments in Alaska, numerous regulators (both state and federal) ensure that operations are not contaminating groundwater or surface water.

For mines, operations are required to monitor and report ground and surface water collection and treatment, hazardous chemical storage and containment, and disposal of wastes—everything from disposing mine tailings to sending solids to landfills.

**Comparing Project-Level Environmental Monitoring (continued)**

For oil and gas developments, a key concern is waste disposal into deep wells. Although oil and gas disposal wells are permitted by three state and federal agencies, the primary regulator is the Alaska Oil and Gas Conservation Commission (AOGCC). In addition to requiring that disposal volumes and reservoirs are monitored, the AOGCC requires groundwater to be monitored around the site. Surface water from nearby ponds, rivers, and creeks is tested. The water quality is checked by chemical analysis for total dissolved solids, pH, hardness, dissolved metals, total metals, and dissolved hydrocarbons. For surface water, biological changes are tested.

In addition to the AOGCC conditions, the state's Department of Environmental Conservation (DEC) also has authority over water quality—requiring monitoring and reporting from wells and surface waters. Other groundwater regulators include the federal EPA and numerous divisions within the state's DNR.

**Biodiversity.** Although both state and federal agencies regulate biodiversity, in many cases the federal government has the highest authority. Offshore, the state formerly had input through a coordinating agency (the Alaska Coastal Management Program), but this state-level program was discontinued in 2011 when the state legislature failed to reach an agreement on the renewal of the program, and funding was cut.

As in Alberta, the federal regulator also has authority over endangered species. The US Fish and Wildlife Service monitors threatened and endangered plant and animal species and their habitats and annually updates the candidate species considered for protection.

The state considers biodiversity when issuing permits for oil and gas or mining developments. Operators are often required to report and track changes in vegetation, wildlife observations and interactions, and any actions undertaken to mitigate conflicts with wildlife. For many projects, operators maintain wildlife interaction plans and require employee training before field operations begin.

Although it is a less frequent regulator for oil and gas projects, the state's Department of Fish and Game is tasked with the protection of fish and game and their habitat in the region. For instance, it has a wildlife action plan and manages in-stream flows to keep water levels sustainable for fish and other wildlife.

**Data availability.** For major mining operations, environmental data are easily accessible online. The Alaska Division of Mining, Land, and Water publishes annual environmental reports for each mine on its website. The environmental reports are similar in content and length to the Alberta mining annual environmental reports.

For biodiversity, the US Fish and Wildlife Service publishes notices regarding species and habitat status at the Federal Register, which are also made available on the agency website. For oil and gas developments, some permit and monitoring data are available online, including air quality permits, water quality data (through the EPA Enforcement and Compliance History Online [ECHO] database), well logs (DNR), and injection well data (AOGCC).

For other information, environmental reports can be obtained through information requests to the operator or the regulatory agency. Although not required, some operators post environmental reports on their company websites.

Because many different agencies issue permits (and therefore require environmental monitoring data), it can be difficult to identify the right agency for a data request (see the appendix for website links to environmental permits and reports). As in Alberta, not all data are digital. In these cases, typically there is a service (and fee) to reproduce and send the information.

## Comparing Project-Level Environmental Monitoring (continued)

### *South Australia*

**Air.** The state's regulator, South Australia Environmental Protection Authority (EPA), is the lead regulator for air. However, like the other jurisdictions compared, there is overlap with federal legislation and the Mining Act.* To comply with both requirements, large mining projects (comparable to oil sands projects) are required to submit air quality monitoring data. As with mines in Alaska, dust is a concern. Ambient dust monitoring sites are established to collect passive dust samples. Emissions from facility stacks are also monitored for pollutants such as acid gases ($SO_2$, $NO_X$) and particulates.

**Water quality.** Both the federal and state governments have jurisdiction over water. Generally the state is the lead regulator. However, in at least one region (the Murray-Darling Basin), the federal government is responsible for all water resource regulation and allocation.** Here the federal government can override state-level rules.

Large mining projects monitor groundwater and surface water. For groundwater, well bores are established around the site to collect water quality and level data. Chemical analysis tracks conventional water quality parameters (total dissolved solids, pH, and hardness). Sites track the water consumed, stored, and released to the environment. Because of the desert location, most sites in South Australia do not have permanent surface water. However, following each major rainfall event, surface water sediments, erosion, and flooding are tracked and reported.

**Biodiversity.** Typically the state is the lead regulator for biodiversity, but both federal and state levels have jurisdiction. For instance, in the Murray-Darling Basin, the federal regulator has authority over fish and river habitat. And like the other jurisdictions, the federal government can protect threatened species.

Large mines in South Australia must monitor vegetation, identify invasive weeds, and document actions taken to mitigate their spread. For mammals, reptiles, and birds, operators document actions to mitigate human interaction. For instance, systems to deter fauna from approaching tailings ponds (fences, deterrent lighting, and gas guns) must be in place. Employees track fauna sightings on a regular basis; periodically, animal movements are monitored and recorded.

**Data availability.** For major mining operations, detailed annual environmental reports are accessible online. South Australia has a comprehensive online database, SARIG, from which annual environmental reports for mines (similar to the mining reports for Alberta and Alaska) can be downloaded.

Oil and gas operators must prepare annual reports that are made available online. The reports include general updates on project activities, including some environmental data. Regional air and water quality data are also available online.

Compared with Alberta and Alaska, where finding the correct regulator can be an obstacle in accessing environmental data, South Australia is simpler. One regulator manages the development and conservation of resources, environment, and public safety (see the appendix for website links to environmental data for Australian mining and oil and gas operations).

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*The national air standards are called the National Environment Protection Measures (NEPMs).
**Source: Australian government Murray-Darling Basin Authority.

See Table 4 and the box "Comparing Ongoing Consultation" for a synopsis of the ongoing consultation process in each jurisdiction.

## Alaska and South Australia Mining Operations Have Formal Requirements

For large mines, both Alaska and South Australia require frequent formal consultation during the project's operational phase. For Alaska, large mines are required to conduct annual public meetings; in South Australia, large mines require a "community engagement plan" as part of their approval, sometimes requiring quarterly meetings. For oil and gas developments in both jurisdictions, however, there are no formal requirements for consultation during operations.

With Alberta oil sands, there is no formal requirement for frequent, ongoing consultation. However, each project's environmental approval must be renewed every 10 years, and this renewal provides an opportunity for public consultation.

Although not always required, most companies engage in voluntary consultation efforts to inform affected stakeholders about ongoing operations, and many have established formal stakeholder relations programs. In general, the amount of information provided voluntarily to stakeholders has increased over time as companies respond to growing demands for information from both affected stakeholders and the public.

**Table 4**

**Key Metrics: Ongoing Consultation Processes**

| | Alberta | Alaska | South Australia |
|---|---|---|---|
| Formal requirement for frequent ongoing consultation | No formal requirement | Large mines require annual meetings. Oil and gas have no formal requirement | Large mines require frequent meetings, sometimes quarterly. Oil and gas have no formal requirement |

Source: IHS CERA.

## Comparing Ongoing Consultation

**Alberta**

In Alberta, there is no requirement for ongoing consultation once a project has been approved, assuming that the developer stays within the boundaries outlined in the approval. However, if the developer needs a change from the approval, one that creates new environmental consequences and risks, it must submit an application related to the change. The new application requires the operator to issue public notices, receive comments, and document the possible impacts of the change. Also, each project's environmental approval must be renewed every 10 years, and this provides an opportunity for public consultation.

Although not required by the regulatory process, in practice most oil sands operators regularly engage stakeholders and effected communities. Data are shared through regular community information meetings or open houses, site tours, regular project updates, e-mail, mailings, and other formal and informal communications.

**Alaska**

In Alaska, large mines are required to host an annual public meeting to review activities with nearby communities, including information on spills and releases, inspections, construction activities, future plans, and reclamation status. Annual environmental performance reports are also readily available. In addition to the required meetings, most large operations engage in voluntary efforts—for instance, regular newsletters or performance reports.

For oil and gas developments in Alaska, an ongoing formal stakeholder consultation policy is not in place. However, as in Alberta, new permits are required when an operation changes from its approved permit conditions. To obtain new permits, the impacts of the change and efforts to mitigate these impacts must be documented. A 30-day open public comment period is required.

For oil and gas, although formal requirements are limited, operators voluntarily inform nearby communities about operations and future plans. For example, the North Slope Borough community has monthly meetings with operators in the region to communicate information on current and upcoming activities.

**South Australia**

In South Australia, all major mines require an approved "Community Engagement Plan"; the plan usually involves a community representative group that meets regularity with the regulator and project operator to review the environmental compliance reporting. However, oil and gas developments do not have a formal requirement.

In one example, a mine hosts quarterly advisory meetings, biannual consultative committee meetings, and annual community days and reports data regularity to the public and affected land owners.*

In addition to formal requirements, large mine operations also engage in voluntary consultation efforts as well as regular meetings and conduct community perception surveys every three years.**

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*Example: Heathgate, Beverley Mine – Mining and Rehabilitation Program, September 2008.
**Source: BHP Billiton, *Sustainability Report 2011.*

## INSPECTION AND ENFORCEMENT

Site inspections provide another check that operations are complying with the regulations established in their approvals. Regulators in Alberta, Alaska, and South Australia all rely on site inspections to ensure that rules are followed. But how do inspections compare among these three jurisdictions? Enforcement is related to inspection—but when an operator is found to be noncompliant, are there consequences?

See Table 5 and the box "Comparing Inspection and Enforcement" for a synopsis of the site inspections and enforcement actions for each jurisdiction.

### All Regions Inspect and Enforce Rules, but Direct Comparisons Are Difficult

All three jurisdictions actively use inspections and penalties to enforce regulation. However, a direct comparison is difficult because of limited data.

Gaining a comprehensive view of all inspection activities is one challenge. Numerous regulators perform inspections in each location, and although some regulators report annual inspections, most do not. A second challenge is the definition of an inspection. An inspection could range from a phone call to a multiday facility audit. Because individual inspection reports are hard to access, even when the total number of inspections is available, the numbers are not necessarily comparable.

Enforcement is also difficult to compare. Whereas some regulators—including Alberta ERCB, Alberta Environment and Water, and US EPA—make violations and penalties available, many do not. Even when data can be compared, the lack of penalties or other enforcement actions may reflect a highly effective and compliant industry rather than a lax regime. A regulatory process is best measured by how quickly it remedies a noncompliance issue, not by the frequency or size of its penalties. It is also difficult to directly compare fines for violations, because violations and the associated risks tend to be unique and thus not comparable.

### Striking a Balance: Inspection Activity and Government Funding

Financial and other resources shape regulators' ability to inspect and monitor operations. Regulators prioritize inspection activities within financial and staffing constraints. In times of rapid investment growth, inspection activity often falls behind. A past survey compared the growth in US wells drilled to the growth in enforcement staff. From 2004 to 2008, the number of US wells drilled increased by 41%, but enforcement staff increased by only 9%.[1]

In the past decade, as Alberta oil sands production grew steeply (more than doubling), inspection activities have had to scale up too. In 2003, the ERCB opened an oil sands office with 20 staff to respond to growing demands in the region. By 2008, the office had grown to 42 staff to keep pace with growth. Between 2007 and 2008, with the staff additions, the number of oil sands mining inspections rose from 18 per year to more than 50.[2] The ERCB

1. "State Oil and Gas Regulators Are Spread Too Thin to Do Their Jobs," December 30, 2009, Pro Publica Inc. Study summarizing data from 22 states http://www.propublica.org/article/state-oil-and-gas-regulators-are-spread-too-thin-to-do-their-jobs-1230, November 2011.
2. Source: ERCB Year in Review 2008.

continues to scale up staffing to keep pace with oil sands activity. Between 2009 and 2010, the number of oil sands inspections almost doubled: ERCB conducted 65 inspections in 2009 and 120 in 2010.

The budget for inspections does not always grow, and budgets are cut when government income decreases. In Alaska, owing to low oil prices and reduced government income, the AOGCC faced a 40% budget cut between 1983 and 1987. Alaskan inspectors publicly complained that reduced inspection activity was increasing the risk of safety issues in oil and gas operations.[1] Since then, spending and inspections in Alaska have increased. Alberta regulators have also faced budget cuts. During the 1990s, the provincial government reduced government spending and debt, cutting funding for many government activities, including for environmental regulation. By 2000, the budget for Alberta Environment and Water was less than C$100 million. That trend has now reversed; the total budget for Alberta Environment and Water (funds for all activities, of which inspections are a small part) increased threefold and is expected to surpass C$300 million in 2011.[2]

To help scale up regulatory staffing through oil and gas activity, some regulators have implemented fees. For example, in Alaska the DEC requires operators to cover the costs incurred by inspections. Alberta's ERCB charges the industry a levy—like a tax—to cover the costs of regulation and also generates revenues by making oil and gas data available for a fee.

1. Source: AOGCC, *Our Resources, Our Past, Our Future: AOGCC - 50 Years of Service to Alaska,* 2008.
2. Alberta Government, *Budget Business Plans—Environment,* 2011 and 2000 http://www.finance.alberta.ca/publications/budget/index.html, December 2011.

**Table 5**

**Key Metrics: Inspection and Enforcement Processes**

| | Alberta | Alaska | South Australia |
|---|---|---|---|
| Are on-site inspections conducted? | Yes | Yes | Yes |
| Are site-inspection data available? | ERCB provides information on total inspections conducted each year. Other regulators inspect, but do not report activities | Few agencies provide information on inspection activities online. Exceptions are DNR (which makes actual site-specific reports available) and EPA | For oil and gas sites, total number of inspections is reported annually. For mining, inspection data are not available |
| Is enforcement a tool available to regulators? | Yes. ERCB can suspend or constrain operations. Alberta Environment and Water generally imposes fines for noncompliance | Yes. Regulators most often enforce through violation notices, and fines if required | Yes. Maximum oil and gas fine is $120,000. As of July 2011, for the first time, mining regulators have the power to use enforcement |
| Are site-specific enforcements available? | Both ERCB and Alberta Environment and Water frequently report noncompliance issues on a site-specific basis | Most agencies publish violations online; few post information on fines (AOGCC and EPA are the exceptions) | Enforcement data are not available |

Source: IHS CERA.

## Comparing Inspection and Enforcement

### *Alberta*

**Inspections.** In 2009, the ERCB's 80 inspectors conducted over 25,000 inspections and audits in the province. In the oil sands, 65 site inspections were conducted in 2009; 120 were conducted in 2010.* Two other oil sands regulators—Alberta Environment and Water and Alberta Sustainable Resource Development—also frequently inspect oil sands facilities. Although these two do not publish information on the total number of inspections, oil sands operators report that Alberta Environment and Water inspections are of similar duration and frequency to the ERCB.

Regulators in Alberta also rely on voluntary self-disclosure. When operators discover their noncompliance, they are obligated to alert the regulatory authorities immediately. One advantage of self-disclosure (in addition to proactively reducing environmental and/or safety risks) is that typically the fines or punishments are less severe compared with noncompliance discovered through site inspections or audits.**

*Source: ERCB, Field Surveillance and Operations Branch Provincial Summary, 2009; and House Energy and Commerce Committee, Subcommittee on Energy and Power, *Dan McFadyn written Statement,* May 23, 2011.
**Source: ERCB, *Directive 019 Revised Edition,* September 1, 2010.

## Comparing Inspection and Enforcement (continued)

Although ERCB reports inspection activities in the aggregate, detailed information from each inspection is not available (for instance, the site visited, the parameters checked, pictures, and notes). However, the ERCB describes site inspections as lasting several days.

**Enforcement.** The ERCB publishes a monthly noncompliance report, and Alberta Environment and Water publishes a quarterly enforcement report. Both reports document the details associated with noncompliance events and actions taken by the regulator. Although the ERCB has the authority to suspend operations until compliance is achieved, to date no oil sands project has been suspended. However, the ERCB has mandated a production cutback to bring a site into compliance with regulations.*

Alberta Environment and Water generally issues fines for noncompliance. The fine varies based on several factors: the severity of the offense, whether the offense was reported voluntarily, the speed with which the violation was reported, any history of prior violations, and any mitigation actions undertaken by the operator. Typically fines or prosecutions for minor violations—for instance a small oil spill or withdrawing slightly more water than licensed—range between $5,000 and $10,000. Examples of higher severity fines issued by the court include $275,000 for storm water escape, $3 million for bird mortalities (from landing in tailing ponds), $675,000 for failing to install pollution control equipment and venting $H_2S$, and $400,000 for dumping sewage.

**Data availability.** Aggregate information about inspections by the ERCB is online, whereas other regulatory agencies do not readily report inspections information. However, both Alberta Environment and Water and ERCB make noncompliance and enforcement actions available online, and the Alberta Environment and Water enforcements are available on the OSIP (see website links in the appendix).

### *Alaska*

**Inspections.** Numerous agencies regulate and have authority to inspect mining and oil and gas operations in Alaska. Visits to remote faculties in Alaska are often costly endeavors, so efforts are frequently combined. On-site inspectors will look for violations outside their authority and report potential violations to the appropriate regulators.

Few agencies provide inspection reports online. The exception is the Alaska DNR (Division of Mining). Its online reports include pictures of the facility and inspector notes. Judging by these reports, large mines have two to three inspections per year from this one agency. Other regulatory agencies make data available upon request. For instance, the AOGCC has seven inspectors focused on oil and gas operations and until 2004 provided a summary of annual inspections online (since the report is no longer available, an information request is required to access current information). The AOGCC generally inspects all new facilities and has two inspectors on the North Slope at all times, plus five available statewide for inspection as needed.

As in Alberta, regulators in Alaska also rely on voluntary self-disclosure and are typically more lenient with penalties when a violation is reported voluntarily.

At the federal level, the EPA also conducts site inspections (sometimes called evaluations). The number of inspections can be tracked with EPA's online database.** Based on the database, in

*In one example for the Suncor Firebag operation, the ERCB determined the "historical and current venting, flaring, and $H_2S$ emissions at the Firebag facility did not comply with ERCB requirements." The ERCB capped the production at the site so that emissions would not exceed limits. The Firebag site ran at restricted capacity for about 10 months, until the issue was resolved. Source: ERCB July 22, 2008, press release, "ERCB rescinds production constraints on Firebag project."

**The EPA online database ECHO has information on compliance with the Clean Water Act, Clean Air Act, Safe Drinking Water Act, and hazardous waste laws. See appendix for website link to database.

## Comparing Inspection and Enforcement (continued)

a five-year period, most Alaskan mines have one or two inspections from this regulator. The EPA issues an annual report that includes the aggregate number of countrywide inspections (21,000 in 2010 and 20,000 in 2009). The individual site inspection reports (inspection notes or pictures) are not readily available.

**Enforcement.** Although most agencies post violation information online, fewer post information on fines. The AOGCC is one exception and posts fines levied. Fines for minor violations range from no fine (voluntary disclosure of failure to perform routine integrity tests) to $10,000 (failure to test blowout prevention system). Examples of more serious violations include a $400,000 fine for not testing safety valves and a $1.2 million fine for an oil production facility operating above the allowed pressure. The EPA also posts information about each of its enforcement actions and fines online.

Other state regulators make Notices of Violations (NOVs) public (on websites or in newspapers). The NOVs outline the specifics of the incident, typically reporting the maximum fine that could be assessed. Most often, after the notice is made public and before any fine is assessed, the operator is offered the opportunity to remedy the violation. In most cases, a fine can be appealed or remedies recommended before a fine is assessed. Only in high-profile cases are the actual fine amounts made public.

**Data availability.** In Alaska, two regulators provide current inspection information online—EPA and Alaska DNR (Division of Mines). As noted, the EPA and AOGCC make fines available online. Most state regulators post notices of violation at their websites or in newspapers, but not fines, unless the enforcement action is unusually controversial or the fine is extremely large.

***South Australia***

**Inspections.** Aggregate data on oil and gas site inspections and noncompliance incidents are published annually. For mining, a subset of selected inspection activities is published annually (for the previous two annual reports, data were limited to inspections on opal fields and exploration activities).

**Enforcement.** For oil and gas, serious incidents are recorded in the annual compliance report. Once a site is found to be in noncompliance, persuasive measures are taken to instigate corrective action. Punitive measures, such as noncompliance fines, are considered as a last resort. Regulators prefer to work with the operator to resolve issues. To date, no punitive measures have been required. If required, fines will not exceed $120,000 for each issue. Other measures the regulator can levy include prosecution or license cancellation.

For mining, prior to July 2011 the South Australia Mining Act had virtually no tools available to enforce compliance. However, with recent (July 2011) amendments to the Mining Act, there are now “environmental directions” and “rehabilitation orders” which enable enforcement. Since implementation of the changes to the Mining Act three Environmental Directions have been issued.*

**Data availability.** For oil and gas, compliance information is available for download in the annual reviews published in the regulator’s (Division of Minerals and Energy Resources) *MESA Journal,* and more detailed compliance reports can also be downloaded from regulators’ websites (see website links in the appendix). At this time, data are not readily available for mining operation enforcement actions.

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*Source: Discussion with PIRSA minerals contact. Data on specific Environmental Directions are not publicly available at this time.

## PART III: PROJECT CLOSURE

At the end of a project's life, the regulators' objective is to ensure that land is reclaimed and returned to productive use. For all jurisdictions for both mining and oil and gas operations, after operations end, the land must be reclaimed. Reclamation requirements for oil developments and surface mining projects differ. With oil developments, instead of completely clearing the land, only part of the land is cleared. As a result, the land is often returned in a condition that is relatively close to its predisturbance state. Surface mining disturbs land to a much greater extent, and consequently, reclamation is of great importance.

Since surface mining is the most important reclamation issue, the scope of this section is limited to a subset of regulation, comparing the closure requirements for mining projects in Alberta, Alaska, and the state of South Australia, considering

- Reclamation and mine closure
- Financial securities and bonds

### RECLAMATION AND MINE CLOSURE

Alberta, Alaska, and the state of South Australia all require operators to reclaim their disturbed land, close mines, and return the land to public use. Table 6 and the box

**Table 6**

**Key Metrics: Reclamation Requirements**

| | Alberta | Alaska | South Australia |
|---|---|---|---|
| Are mine closure plans updated regularly? | Yes, every five years | Yes, every five years | Yes; requires a current closure plan |
| Is there a clear certification process with measurable outcomes? | Current framework exists, and this is now being strengthened with more specific sign off criteria | Yes, outcomes defined in closure plans and laws; multiple regulators have authority and sign off separately | Yes, closure requirements have outcomes with measurable criteria |
| Are project-level data available? | Similar among these locations. Project-level status on amount of land disturbance and reclamation progress is online at OSIP. More detailed information requires request | Similar. Project-level status is online in annual reports (amount of land disturbance and reclamation). Other information requires request | Similar. Reclamation plans and annual mining reports (that provide high-level reclamation status) are online. Other information requires request |

Source: IHS CERA.

"Comparing Reclamation Requirements" highlight project-level reclamation requirements for each jurisdiction.

For all three jurisdictions, mine closure plans are included within each project's approval documents. Most often these include details on the pre- and postdevelopment land capability, a conceptual plan to close the mine, and timelines for reclamation progress. Despite the level of detail in each mine's approval, the definition of "reclaimed" land and the pace of reclamation are often open questions for stakeholders who want the land restored as closely as possible to its predisturbance state.

### Allowing for Flexibility in Mine Closure Plans

For Alberta and South Australia, the legislative or regulatory definition of reclaimed land is somewhat vague and open to interpretation. For Alberta, the goal is "equivalent land capability." South Australia provides a series of broad reclamation objectives, such as reducing or eliminating adverse effects and financial liabilities after closure, ensuring that future risk and liability are controlled to an acceptable level, and reducing the need for long-term monitoring requirements.[1] Although these broad definitions can leave room for interpretation, they are also widely applicable—they could equally be applied to restoring boreal forest, desert, or arid grasslands ecosystems. And they are flexible, allowing the reclamation plans to accommodate the uncertainty of planning long into the future.

Alaska's DNR takes a slightly different approach by providing more specific reclamation performance standards and milestones in its general regulations. For instance, the DNR mining regulations stipulate that one year after reclamation, the land should achieve revegetation, and within five years, the land should not need fertilizer or reseeding. It also outlines conditions to stabilize and recontour the land and water streams.[2]

In their original project applications, most mines assume a long life—typically spanning two or three decades or more. However, because of volatile commodity price cycles, resource mines have a history of early closures. For this reason, Alaska, Alberta, and South Australia all require every mine to have a current closure plan. Alaska requires the mine closure plan to be updated every three to five years and also requires a third-party environmental audit prior to this renewal process. For Alberta, the mine closures plans are updated every five years.[3] South Australia also requires mine closure plans to be updated regularly.

In addition to keeping the mine closure plans current to ensure that plans evolve with the mine's actual development, in each jurisdiction the lead regulator requires operators to provide annual update reports; these can include research initiatives, past reclamation achievements, current level of disturbance from mining, and future plans relative to the closure plan. Collaborative research is important to help reduce the uncertainty associated with reclamation—all three jurisdictions outlined plans to research and pilot new techniques for reclamation areas, so these new techniques remain uncertain. The Alberta and Australia plans for new research were the most detailed and included local stakeholder input.

1. Source: Australian and New Zealand Minerals and Energy Council, *Strategic Framework for Mine Closure,* 2000.
2. Source: Alaska DNR, *Mining Laws and Regulations, Land Reclamation Performance Standards,* 11 AAC 97.200.
3. At least every 10 years, with the renewal of Alberta Environment and Water's approval for the mine, and an additional requirement for an update in the middle of the approval.

The US Army Corp of Engineers (COE), which is one of the regulators with authority over mine reclamation in Alaska but typically not the lead regulator, avoids the problem of out-of-date closure plans. The COE stipulates in the original approval that reclamation will require an additional permit, but this permit (and the detailed reclamation plan that supports it) is only needed near the time of closure. One advantage of the COE approach is that the plan reflects current technologies and public expectations—as opposed to a carry-over approval that can be out of date.

### Strengthening Performance Metrics for Mine Closure

Ideally, the mine closure plans include measurable criteria to enable the regulator, operator, and the public to clearly gauge when closure outcomes are achieved. Of the three jurisdictions compared, the Alaska mine closure plans provided the most specific objectives—outlining specific periods to meet water quality and vegetation performance metrics within their approval documents.

Alberta recognizes the need to augment existing mine closure plans with more specific objectives. In Alberta, to help clarify the definition of reclamation, specifically for oil sands mines, CEMA is creating specific indicators to define and measure the success of reclamation. Its recommendations will be used to help to inform Alberta's updated mine closure policy. In addition, the Alberta government is now developing a more detailed process to guide future oil sands mining land certifications in the province.

### Surface Mining Makes for Changes

In all jurisdictions, when land is disturbed on the scale and extent required for surface mining, the land is changed. In all regions, development rock piles (or overburden piles) and tailings piles are sloped, topsoil is applied, and vegetation is planted; but the piles remain permanent features.[1] Terraced slopes left from mining are contoured and planted with trees; however, their slope is permanently altered.

Finding the balance between environmental and economic prudence is complex, and sometimes postmining land changes are very large. In a recent South Australian project approval, a 1 kilometer deep open pit will remain after mine closure since filling a hole this large would be cost prohibitive. The pit will be a permanent land feature and is considered to have the potential to become a tourist attraction. This is not a unique situation. In Lead, South Dakota, after a 2002 mine closure, a 2 kilometer deep open pit is now open for mining tours. Alaska's DNR has even codified this situation within its regulations, stating that the mining pit can remain after the site is closed if the steepness of the wall makes it impracticable to contour or backfill; however, the operator is required to leave it in a stable condition for safety reasons.

Disposal of mine tailings—the sometimes toxic mining waste left over after processing the mined ore—is another concern. In oil sands mining, current mine closure plans assume that part of the oil sands tailings will be disposed of in end-pit lakes (EPLs).[2] EPLs are an untested part

1. For all locations, the original topsoil is stored and reused for reclamation.
2. Oil sands tailings waste has been found to be toxic to aquatic life in assays involving fish and microorganisms, but the toxicity decreases over time. Naphthenic acids removed from bitumen during the extraction process are the primary source of this toxicity.

of oil sands mining reclamation. The plan is to create engineered bodies of water in mined-out areas that contain fluid fine tailings and other mining waste at the bottom, topped by a layer of fresh water; these would become a permanent part of the landscape after reclamation. However, the use of EPL is still conditional based on a successful, large-scale demonstration that proves tailings can be contained at the bottom of the lake—not released into the environment. Such a demonstration is planned for 2012.[1] Disposal of mining waste can be contentious. In Alaska, a gold mine was permitted to dispose of mining waste (crushed rock and produced water, called "froth flotation") in a naturally occurring lake. Environmental groups challenged the decision, but after numerous appeals, the mine was eventually permitted to dispose of the waste, provided that the fresh water that fed into the lake was rerouted into the watershed free of contamination. In other cases, toxic tailings are entombed and permanently impounded at mining sites.

## Comparing Reclamation Requirements

### *Alberta*

**Definition of reclaimed land.** For each oil sands mining operation, mine closure plans define reclamation obligations, including conceptual plans and timelines, and broad performance goals. Areas in which reclamation plans and procedures have greater uncertainty are highlighted, and plans to research and pilot new methods are detailed (for instance, research new methods to restore wetland areas or dry tailings). These plans are generally updated about every five years.

The current draft of the proposed LARP also refers to Alberta's new progressive reclamation strategy, which includes an enhanced reclamation certification program, a transparent public reporting system, and a new progressive reclamation financial security program. In support of these objectives, the CEMA, a multistakeholder group that includes members of industry, government, and the local community, has undertaken an effort to help clarify the definition of reclamation for specific oil sands mines. The CEMA Reclamation Working Group issued a report that outlines 59 specific indicators to define and measure the success of reclamation efforts.* These recommendations are being used to inform future policy.

What does reclaimed mining land look like? After mining and reclamation, the land cannot return to its state before development. For example, the external tailings areas (large dikes built aboveground to hold tailings) will remain hills and be sloped and planted with vegetation. Some of the mine's open pits will not be backfilled and will become lakes. Some open pits as EPLs could contain mining wastes. However, using EPLs as a reclamation method is still contingent on its successful demonstration.

Prior to development of oil sands mines, much of the mined area consisted of wetlands—bogs, fens, and swamps. Although collaborative research involving industry, academia, and local Aboriginal groups is under way to increase knowledge on restoring biodiversity in land reclamation, the science of restoring wetlands is in its infancy. Successful restoration of peaty wetlands (bogs and fens) is a particular challenge and has not been successfully demonstrated to date. Therefore, reclaimed land is likely to consist of a combination of highland forest and wetlands.

**A Framework for Reclamation Certification Criteria and Indicators for Minable Oil Sands,* December 2009, CEMA.

1. The first large-scale test is set to start in 2012 at the Syncrude oil sands mining operation.

## Comparing Reclamation Requirements (continued)

**Process to certify land "reclaimed."** For oil sands mining projects to date, one small parcel of land (about 1 square kilometer, or 0.4 square miles) has been certified as reclaimed by the Alberta government and released back to the public. To date, the regulator's approach has been to not certify lands within an active mining site, so although technically operators have reclaimed more lands, these have not been officially certified as reclaimed.

The current certification process for mines is outlined in the government of Alberta's "Guide to the Preparation of Applications and Reports for Coal and Oil Sands Operation (1991)." The guide details the need for site inspections and monitoring of soil chemistry and erosion potential, forest growth, water characteristics, and wildlife and fisheries inventories. Consistent with the objectives of LARP and leveraging the recommendations made in the CEMA Reclamation Working Group's Framework, the Alberta government is now developing a more detailed process to guide future oil sands land certifications in the province.

**Data availability.** Land reclamation certificates are available online from Alberta Environment and Water's Environmental Site Assessment Repository (ESAR) database. However, the certificate documents are brief, only one or two pages. For detailed information on the certification process (and supporting documentation), an information request is required. Through the life of the project, oil sands operators must update the regulator on the status of land disturbance, monitoring, and reclamation progress. Summary metrics for each operation—including the total area disturbed and reclaimed—are available at the OSIP. Each operation submits more detailed information to the regulator in an annual Conservation and Reclamation report, and this information is available at the Alberta Government Library in Edmonton.

### *Alaska*

**Definition of reclaimed land.** In Alaska, multiple regulators are responsible for reclamation. Three key regulators are the DNR, Bureau of Land Management (BLM), and the US Army COE. Although not discussed here, the Alaska Department of Environmental Conservation (ADEC), the EPA, the US Forest Service, and local authorities or boroughs also have jurisdiction. Although numerous agencies have authority over reclamation, the DNR is the lead regulator for mining reclamation and typically coordinates activities with other regulators.

DNR requires an approved reclamation plan, updated every five years, and bonding for all mining operations in Alaska regardless of the type of land being developed (private, state, municipal, or federal lands). The DNR requires each mining operation to outline site-specific reclamation requirements within its plan of operations. The plan includes details on postclosure land use (water, soil, biodiversity) and timelines. The plan also details reclamation areas that are uncertain, identifying potential areas for future research. In addition to site-specific plans, the DNR's regulations and laws also outline performance metrics for mine closure.

What does reclaimed mining land look like? For surface mining projects, postdevelopment land is not the same as before mining. In fact, the DNR regulation clearly states that land will be altered postclosure. Restoration work could include "backfilling, contouring, and grading, but a miner need not restore the site's approximate original contours." Further, the mining pit can remain after the site is closed if the steepness of the wall makes it impracticable to contour or backfill.

**Process to certify land "reclaimed."** For Alaska mines, the DNR regulation outlines specific metrics for successful reclamation. Combined with the metrics in each project approval, operators must meet these requirements for certifying the land as reclaimed. Typically, and as in the Alberta oil sands, an operator will reclaim sections of the mine no longer in operation even though other acreage is still being mined. Federal regulators, including BLM and the COE, also sign off on

**Comparing Reclamation Requirements (continued)**

mine reclamation. Although DNR is typically the lead regulator, the federal agencies maintain their own discretionary authority to determine when a site has been reclaimed or restored on federal lands and have their own specific criteria and sign-off.

**Data availability.** For mining sites, the original reclamation plans and criteria to reclaim the land are available online with DNR. In addition to the operating plan, the mines are required to provide annual updates similar to those in Alberta (status of area disturbed, reclamation efforts, research, and monitoring). For documents outlining the procedure and information supporting a specific mine closure, a data request to the regulator is required.

***South Australia***

**Definition of reclaimed.** In Australia, the term for reclamation is "rehabilitation." A current mine closure plan must define the requirements for rehabilitation and closure. For large mines, plans include a conceptual representation of the mine at end of its life, broad goals such as plans to reestablish vegetation, methods to minimize seepage from tailings, and timelines. Reclamation areas that are uncertain are outlined with plans for future research, for instance, on reclaiming tailings or optimizing growth of vegetation. The plans are updated regularly.

In South Australia mining, a key aim of the mine closure plans is to eliminate any "third party" residual impacts (for instance, a tailings dam that remains postclosure would require the operator to establish a system to continually monitor and maintain the dam to avoid any adverse effects to public lands or future costs to the government). Mine closure plans include closure outcomes with measurable criteria.

What does reclaimed mining land look like? As elsewhere for surface mined projects, the land looks different. For example, in one reclamation plan, terraces of over 200 meters will be sloped and planted with vegetation. Tailings are left on site—sometimes encapsulated, either in earth-lined pits or, for more toxic tailings, sealed in lined pits and covered.

**Process to certify land "reclaimed."** The closure objectives are defined within the mining approval. Specific objectives include targets to meet acceptable water quality standards within three years, assurance that waste pits are stabilized and not contaminating the ground or water, and plans to ensure that land forms remain stable.

**Data availability.** Each mine submits annual mining and rehabilitation compliance reports with high-level information on the amount of land disturbed. As in the other regions, specific information related to a mine closure must be requested.

## FINANCIAL SECURITY AND BONDS

Despite the specific criteria outlined in mine approvals, mines have a long history of failing to meet closure requirements, and governments are still paying for this legacy. In 2010 alone, Alaska spent over $2 million mitigating safety issues posed by the state's abandoned mines.[1] Today, South Australia is saddled with the costs for reclaiming three abandoned mines. To protect the government in the future, all three jurisdictions—Alberta, Alaska, and South Australia—now require that mine operators post financial securities to protect taxpayers from covering the costs of reclaiming abandoned mines.

1. Funds come from the Abandoned Mine Program that addressed abandoned mines prior to August 1977 and include both federal and state funds.

Table 7 and the box "Comparing Financial Securities and Bonds" evaluates the financial protection required for surface mining operations in Alberta, Alaska, and South Australia.

## Alberta's Unique Financial Security Method

Many aspects of financial securities for reclamation are similar across the regions. For instance, all regions require operators to provide regular updates and estimates of the current liability. The Alberta system has a different methodology from the other jurisdictions, however. For Alaska and South Australia, the financial security funds are intended to cover all estimated reclamation costs; whereas in Alberta, the value of the resource (which in this case is bitumen) is considered an asset that offsets the cost of reclamation (unless the mine is within 15 years of the end of its life). This is a key difference between Alberta's program and the others. In Alberta, initially, the estimated reclamation liability is not required to be 100% funded by the security.

The lack of 100% coverage of reclamation liability in the early and middle stages of a project's life introduces some uncertainty on the ultimate payment of reclamation costs. For instance, if the oil price drops sharply, the value of the corresponding asset assumed to cover the reclamation liability also drops. To address this potential scenario, however, each operator submits an annual estimate of its reclamation liability, assuming a third party performed the work. At any time, if the combined value of the bitumen asset and the financial security is not three times higher than reclamation liability, then the mine must provide an additional financial security to fund the gap. By this mechanism, the program is designed to cover the liability even when the price of oil is low.

**Table 7**

**Key Metrics: Financial Securities for Mines**

| | Alberta | Alaska | South Australia |
|---|---|---|---|
| Financial security methodology | Asset-to-liability approach; bitumen covers a significant part of the reclamation liabilities in early to middle stages of project life | Bond must provide 100% of the current reclamation costs | Bond must provide 100% of the maximum annual liability at any time in the mine's life |
| Frequency of security updates | Annually | Every five years at least | At any time |
| Range of financial securities for an individual mine | $30 to $359 million | $16 to $300 million | Not available |
| Availability of project-level data | Status of disturbed land and the value of the security are online | Status of disturbed land and the value of the security are in some annual reports; others available by request | Not available |

Source: IHS CERA.

## How Does the Size of Alberta's Security Compare?

Sometimes to compare the financial securities among jurisdictions, the size of the security (dollars) is compared to the amount of land disturbed (area). Because mining reclamation costs vary significantly across various mining operations, at times these types of metrics can be misleading. For example, some mines in Alaska are in remote locations with fly-in/fly-out access only; other operations must generate power on site, while others are on the grid; and some mining processes have toxic effluents that are costly to reclaim. Considering all active surface mining operations in Alaska, the size of the security currently ranges from US$40,000 to over US$130,000 per hectare of land disturbed (average is US$75,000 per hectare of land disturbed), and the total value of the bond for an individual mine ranges from US$16 million to over US$300 million.[1]

In Alberta, the total value of the financial security for an individual mine ranges between C$30 million and C$359 million. Because Alberta has a different methodology, and not all of the reclamation liability is covered by the value of the financial security, a metric such as the value of the financial security per hectare of land disturbed is not useful. A more comparable value could be the money that Alberta requires if the operator fails to reclaim the hectares promised, which is C$75,000 per hectare of land disturbed (this value will be reviewed in three years to confirm that it is sufficient to cover actual reclamation costs). Also note that the value of the Canadian and US dollars is currently near parity.

Alberta and Alaska provide readily available data on both the funds reserved for reclamation and the status of the land disturbance from mining. South Australia has the lowest data availability in this regard—both the disturbed land area and the funds reserved to cover reclamation costs are not readily available.

### Comparing Financial Securities and Bonds

***Alberta***

**Financial security.** Although financial securities were required in the past, Alberta Environment and Water announced new requirements in 2011, termed the asset-to-liability approach. With the new program, at the start of a project's life, the operator is required to provide immediate funds—C$30 million for mine and C$60 million for mine and upgrader. For most of the project's life, the value of the bitumen is used to cover the remainder of the reclamation costs. Only when the project starts nearing the end of its life (defined as when 15 years of reserves remain) are more funds required. By the time six years of reserves are left, the cost for all outstanding reclamation must be backed by financial securities.

Although an additional financial security is not typically required in the early to middle stages of a project's life, each operator must submit an annual estimate of its reclamation liability, assuming that a third party would perform the work. The Alberta government may audit the estimate.

Most oil sands mines operating before 2011 (before the new program was introduced) had more than C$30 or C$60 million in their financial security, and these funds have been retained. In these cases, the value of the financial security for an individual mine ranges between C$110

1. Source: DNR, supplied by request and includes reclamation costs for Red Dog mine, Rock Creek Mine, and Fort Knox mine, November 2011.

**Comparing Financial Securities and Bonds (continued)**

million and C$360 million.* The security is released back to the operator when the estimated liability is reduced.

Since no oil sands mines have reached the 15 years of reserve life milestone, the security values do not reflect the total reclamation liability. Part of the liability is covered by the value of the bitumen reserve. A more comparable value could be the money that Alberta requires if the operator fails to reclaim the hectares promised, which is C$75,000 per hectare of land disturbed.

**Data availability.** The Alberta government reports detailed information on the financial securities for oil sands mines in its Environmental Protection Security Fund Annual Report. The report publishes the amount of security posted by each operation and is available online. Alberta Environment and Water has also started to post the status of mining lands and the value of financial securities for each operation on an annual basis at the OSIP (see appendix for website links).

***Alaska***

**Bond.** In Alaska, large mine operators must provide a bond that covers 100% of the costs associated with reclaiming the land. The bond amount can be increased at any time and during project amendments if needed. At minimum, the bond amount is revisited every five years. As an alternative to an individual financial assurance, the DNR established a bonding pool for mining operations. The bonding pool significantly reduces the financial requirements for an operator, but the bonding pool is not typically available to large or higher risk mines.

The regulator (typically the DNR, although sometimes comanaged with other state or federal agencies) establishes the amount of money required for the bond. The value of the bond varies significantly depending on the type of mine, the area of land disturbed, and the risks associate with contamination.

Currently, monies reserved for an active individual surface mine range from US$16 million to over US$300 million, or from US$40,000 to over US$130,000 per hectare of land disturbed (average value is US$75,000 per hectare of land disturbed).**

**Data availability.** The bond amounts and current reclamation cost estimates are contained within each mine operator's annual environmental report (see website link in the appendix). The current status of land disturbed is sometimes reported in a mine operator's annual environmental report, but not in every case. When not available, the data can be requested from the regulator.

***South Australia***

**Bond.** Mines in South Australia require a bond to cover the maximum annual liability at any time in the mine's life; this may not be the value in the final year of operations. The full value of the bond is due before mining starts. The value of the bond is estimated based on the approved mine plan and assumes costs for a third party to perform all of the reclamation work. The amount can be updated at any time.

**Data availability.** The bond amounts provided by each operator are not readily available and would require an information request to access. For individual mines, the annual mining and rehabilitation compliance report has only high-level data on the amount of land disturbed by operations.

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*Source: Ministry of Environment, Environmental Protection Security Fund Annual Report, March 2010.
**Source: DNR, supplied by request and includes reclamation costs for Red Dog mine, Rock Creek Mine, and Fort Knox mine, November 2011.

# CONCLUSION

## THE FUTURE OF REGULATION IN OIL SANDS

This report is a snapshot of regulation today. Regulation of oil sands (as well as in other jurisdictions) is continually evolving, adapting to changing levels of environmental stress and keeping pace with the changing expectations of the public. For oil sands, major areas of change on the horizon include the development of a regional plan and work to strengthen regional monitoring.

### Land Use Framework for the Oil Sands Region

When oil sands development was collectively of a lesser scale than it is today, a regulatory environment that focused on project-level criteria may have been sufficient. However, oil sands are now poised for rapid growth (doubling over the next 10 years), and the regulatory system must keep pace with its larger scale.

To respond to that need, after multiple drafts and three stakeholder consultation cycles, Alberta released the draft LARP oil sands regional plan in August 2011.[1] The proposed plan has not yet been approved, and prior to being ratified, it must clear one final step: approval by the Alberta government cabinet. The plan aims to adopt a cumulative management approach for the region—setting thresholds for water, air, biodiversity, and land that apply to the region as a whole. In the future, the environmental impacts from all development (including oil sands operations) need to stay within the regional thresholds.

The plan establishes approximately 16% of the region's land to be managed as new conservation areas, in addition to the 6% that was already protected as wildland provincial parks intended for conservation management.

### Strengthened Regional Monitoring

In the oil sands region, local stakeholders have raised concerns for many years that the monitoring of rivers and streams is not robust enough to detect contaminants. Although oil sands operators are not permitted to release mining contaminated water from their sites, it has been suggested that some waste could unintentionally enter the water system, potentially leaking through the dikes that hold tailings and waste water. Contaminants could also be carried by the air and deposited onto the snowpack.

To better understand these issues and the monitoring requirements for the region in general, the Alberta and federal governments separately formed expert panels to independently investigate the issues and make recommendations to strengthen monitoring in the region—including air, water, and biodiversity. In 2011 each released reports that make recommendations to improve regional monitoring. Going forward, the two governments are expected to join efforts in implementing the new recommendations.

1. Government of Alberta, *Draft Lower Athabasca Regional Plan 2011–2021,* August 2011.

## CONCLUDING REMARKS: ASSESSING ENVIRONMENTAL REGULATIONS IN THE CANADIAN OIL SANDS

The environmental regulatory system in the Canadian oil sands has been depicted as "weak" by its critics and "stringent" by its supporters. Oil sands development, like all forms of energy extraction, has environmental impacts. However, risks from oil sands development are something to be managed. They cannot be viewed in isolation; they must be compared with alternatives. The critical question is, Does the oil sands regulatory system minimize the risks in a way that is comparable to other places?

To be sure, this report is not a comprehensive list of all aspects of the environmental regulatory system or a comparison to all possible jurisdictions; rather, it serves as an illustrative case study using some specific examples. In comparing the regulatory regime in the oil sands to two peers—Alaska and South Australia—across specific examples, there are many more similarities than differences. Of course some aspects make direct comparisons difficult; but for the cases considered, regulation in the Canadian oil sands is similar to these peers in procedures, data requirements, and measures to protect the environment.

### Project Approval

In general, the project approval, including the data required, data availability, public input, outcomes, and process, is similar across the three jurisdictions. There are some differences in how public consultation is conducted; Alberta's hearings are formal, courtlike proceedings, whereas Alaska and South Australia typically use a "town hall" style meeting.

Public consultation is an important part of project approvals in all places, but consultation is meaningful only if can effect an outcome. In all locations, we could find examples where public input materially changed some aspect of a project.

Alberta has not yet denied an oil sands approval. For Alaska and South Australia denied approvals are also relatively rare, but regulatory delays are common.

In the Alberta oil sands, lands are leased to industry for the purpose of oil extraction prior to initiating the study of environmental impacts and public consultation. In Alaska, for developments approaching the size of oil sands, the process proceeds in the opposite order. Before a major area is opened up to oil and gas or mineral extraction in Alaska, an environmental impact assessment is conducted and stakeholders are consulted. Only after the decision is made to approve resource extraction are lands awarded to resource developers. For Alaska, state regional land management plans (that identify development and conservation goals for the region as a whole) are already established before the lands are leased for resource extraction. The province of Alberta is now considering a regional plan (LARP) for the oil sands region. Under the proposed plan, approval for oil sands projects, as for projects in Alaska, would have regional stipulations and conditions.

### Ongoing Operations

During the ongoing operations, the most significant difference among the three jurisdictions is the level of data availability. For Alaska mining and South Australia, detailed project-level environmental reports are generally more readily available than for Alberta oil sands and Alaska oil and gas operations. In the Alberta oil sands, the recently launched OSIP provides project and regional metrics. However, to access more detailed environmental data, such as the comprehensive environmental reports that each operator submits to the regulator, an information request to the regulatory agency is required. One exception is for oil sands mining projects; for these operations, detailed project-level data can be accessed from the Alberta Government Library.

Another difference is that regulations in Alaska and South Australia require mine operators to consult regularly with the public and key stakeholders during operations; however, oil and gas operators do not have formal requirements. In Alberta, oil sands projects do not have formal requirements to consult regularly with the public during ongoing operations. However, even when not formally required, many operators consult voluntarily with local stakeholders on a regular basis.

All regions use inspection and enforcement to ensure that regulations are followed. Alberta is comparable to or better than the other jurisdictions when comparing the availability and transparency of inspection and enforcement data.

### Project Closure

For project closure we focused on mining operations, as these projects pose the most critical reclamation issues. Creating specific goals to define successful reclamation is a challenge for all jurisdictions. However, Alaska has the most detailed requirements (contained in project-specific state and federal approvals as well as codified into regulations). Alberta is in the process of strengthening its mine closure processes.

All three regions require funds to be reserved to cover an operator that goes bankrupt or cannot deliver on reclamation requirements. The method for covering the costs in Alberta differs from the others. For Alaska and South Australia, the funds are intended to cover all estimated reclamation costs; whereas in Alberta, the value of the resource (which in this case is bitumen) can be used as an asset to offset part of the reclamation cost (unless the mine is within 15 years of the end of its life).

### In Summary

Among the aspects we compared, there are many more similarities than differences between Alberta's regulation and those of its peers, Alaska and South Australia. Similarities include the approval process, the use of inspections, enforcement, public consultation, data requirements, monitoring, and outcomes. Returning to the key question, among the aspects that we considered, the oil sands regulatory system is certainly not "weak" and manages project-level risks in a way that is, in many respects, comparable to South Australia and Alaska.

## REPORT PARTICIPANTS AND REVIEWERS

On June 28, 2011, IHS CERA hosted a focus group meeting in Calgary, Alberta, providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to environmental regulation. 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
Alberta Energy Resources Conservation Board (ERCB)
Alberta Ministry of Environment and Water
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)
Marathon Oil Corporation
Natural Resources Canada
Nexen Inc.
Oil Sands Research and Information Network (OSRIN)
Pembina Institute
Primary Industries and Regions South Australia (PIRSA)
Shell Canada
State of Alaska Department Natural Resources
Statoil Canada Ltd.
Suncor Energy Inc.
Total E&P Canada Ltd.
TransCanada Corporation

## IHS CERA TEAM

**Jackie Forrest, IHS CERA Director, Global Oil**, leads the research effort for the IHS CERA Oil Sands Energy Dialogue. Her expertise encompasses all aspects of petroleum evaluations, concentrating on refining, processing, upgrading, and products. 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 the team that developed the North American unconventional oil outlooks and recommendations 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. 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. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**Molly Birnbaum is a Principal Scientist with ARCADIS-US** and has over 25 years of experience in the environmental and natural resources profession dealing with in-field applications, planning and project design, permitting strategy, regulatory and policy issues, and dispute resolution. Her expertise includes the fields of natural resources management, energy policy, and law. She has worked in the United States, primarily in Alaska, as well as in Alberta, Canada, and conducted project work with both government and private industry in matters relating to air, land, and water management. Regulatory experience includes energy (oil and gas) and electrical generation permitting and permitting strategies, with particular expertise in state and federal gaps analysis, regulatory compliance application analysis, permitting strategy and coordination, and policy research. In addition to working with the energy industry in Alaska, she has consulted with the electrical power generation industry in researching renewable energy initiatives and strategies, used in both Canada and the United States. Ms. Birnbaum holds a BA, an LLB from the University of Calgary, and a LLM from the University of Houston.

**ARCADIS** is full service international company providing consultancy, design, environmental, engineering and management services in the fields of oil and gas exploration, infrastructure, water, environment and buildings. ARCADIS has over 16,000 professionals worldwide, with over 300 offices and in 40 countries assisting national and international companies to solve engineering and environmental problems since 1888. The ARCADIS group of companies has its headquarters in the Netherlands, and its network of offices stretches across Europe, the United States, the Middle East, the Caribbean, Latin America, Africa, Asia, and the Russian Federation. The ARCADIS Alaska office is primarily active in upstream planning and permitting, and its services are generally in support of oil and gas and mineral exploration and development and government projects. ARCADIS also offers compliance services to clients for existing facilities and development.

**Samantha Gross, IHS CERA Director,** specializes in helping energy companies navigate the complex intersection of policy, environment, and technology. She is the manager of the IHS CERA Global Energy service. She led the environmental and social aspects of IHS CERA's Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance,* including consideration of water use and quality, local community impacts, and Aboriginal issues. Ms. Gross was also the IHS CERA project manager for *Towards a More Energy Efficient World* and *Thirsty Energy: Water and Energy in the 21st Century,* both produced in conjunction with the World Economic Forum. Additional contributions to IHS CERA research include reports on the water impacts of unconventional gas production, international climate change negotiations, US vehicle fuel efficiency regulations, and the California low-carbon fuel standard. Before joining IHS CERA she 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.

We also gratefully acknowledge the contribution of **Jason Beck** to this report.

# APPENDIX
# WEBSITE LINKS TO DATA SOURCES

## MAJOR REGULATORY AGENCIES IN ALBERTA, ALASKA, AND SOUTH AUSTRALIA

### Alberta

Although numerous other government agencies have jurisdiction, the primary agencies that regulate oil sands are

- Energy Resources Conservation Board (ERCB)—development and conservation of resources
- Alberta Department of Environment (AENV)—regulates the environmental parameters of operation
- Alberta Department of Sustainable Resource Development (SRD)—regulates surface disturbance

The Canadian federal government also has oversight. The primary agencies are

- Department of Fisheries and Oceans and Transport Canada—fish habitat or changes to the navigation of waterways
- Environment Canada—migratory birds and endangered species
- Canadian Environmental Assessment Agency (CEAA)—coordinates federal review of project applications and environmental applications
- Major Projects Management Office (MPMO)—single window to facilitate major resource projects regulatory review process

### Alaska

Although numerous other government agencies have jurisdiction, in Alaska the main regulators are

- Department of Natural Resources (DNR)—regulates use of resources (oil, gas, minerals, water) and oversees the protection of cultural sites and fish habitat
- Department of Environmental Conservation (DEC)—issues air quality permits and regulates the disposal of waste
- Alaska Oil and Gas Conservation Commission (AOGCC)—prohibits the waste of crude oil and natural gas, strives to ensure greater resource recovery

Other regulators in Alaska include the Department of Fish and Game, the Department of Public Safety, and the Department of Labor and Workforce Development. Federal agencies include the Army Corps of Engineers (COE), the Bureau of Land Management (BLM), the Environmental Protection Agency (EPA), and the Bureau of Indian Affairs, among others.

### South Australia

The central regulator for the energy industry in South Australia is Primary Industries and Resources South Australia (PIRSA). South Australia has a unique system, with a single regulator managing the development and conservation of resources, environment, and public safety.

## PART 1—PROJECT APPROVAL PROCESS LINKS

### Alberta

Alberta Environmental Protection and Enhancement Act for EIS contents:. http://environment.alberta.ca/01530.html

Canada Federal Environmental Assessments and related documents:

http://www.ceaa.gc.ca/default.asp?lang=En&n=4F451DCA-1

Alberta ERCB process for environmental assessments, and current projects and documents:

http://environment.alberta.ca/01495.html

### Alaska

Alaska—Regulations for Defining National Environmental Policy Act (NEPA) (40 C.F.R. 1502 for EIS requirements):

http://ceq.hss.doe.gov/nepa/regs/ceq/toc_ceq.htm

Alaska—Final Environmental Impact Statement (EIS) listing for major offshore oil developments:

http://www.alaska.boemre.gov/ref/eis_ea.htm

Alaska—Listing of large mines and associated permits and EIS by project:

http://dnr.alaska.gov/mlw/mining/largemine/

### South Australia

South Australia—Major project's approval process, EIS documents, and decisions:

http://www.planning.sa.gov.au/index.cfm?objectId=B0D6F25D-96B8-CC2B-63BE28584A11F809

South Australia—PIRSA Minerals South Australian Resource Information Geoserver (SARIG) online database stores past EIS documents related to resource development:

http://www.pir.sa.gov.au/minerals/sarig

South Australia—Oil and Gas approval process and links to documents:

http://www.pir.sa.gov.au/petroleum/environment/regulation/eir_intro

South Australia—Mining approval process:

http://www.minerals.pir.sa.gov.au/publications_and_information/guidelines

South Australia Current Mining Act, including July 2011 Amendments:

http://www.legislation.sa.gov.au/LZ/C/R/Mining%20Regulations%202011.aspx

## PART 2—ONGOING OPERATIONS LINKS

### Environmental Monitoring Data Links

*Alberta*

Alberta—Oil sands air monitoring stations. Wood Buffalo Environmental Association (WBEA):

http://www.wbea.org/

Alberta Environment and Water Oil Sands Information Portal (OSIP):

http://environment.alberta.ca/apps/osip/

Summary of National Pollutant Release Inventory (NPRI):

http://www.ec.gc.ca/inrp-npri/default.asp?lang=en&n=629573FE-1

*Alaska*

Alaska—Environmental data for large mines:

http://dnr.alaska.gov/mlw/mining/largemine/

Alaska—Enforcement and Compliance History Online (ECHO) includes water quality reports by major facility:

http://www.epa-echo.gov/echo/index.html

Alaska—Air quality permits:

https://myalaska.state.ak.us/dec/air/airtoolsWeb/PublicPermitListings.aspx

Alaska—Oil and gas injection data:

http://doa.alaska.gov/ogc/orders/dio/dioindex.html

Alaska—US Fish and Wildlife Service annual notices regarding species considered under protection under the Endangered Species Act:

http://www.nmfs.noaa.gov/pr/species/esa/other.htm

http://alaska.fws.gov/fisheries/endangered/pdf/consultation_guide/4_Species_List.pdf

### *South Australia*

South Australia—Mining annual environmental reports—PIRSA Minerals SARIG online database:

http://www.pir.sa.gov.au/minerals/sarig

South Australia—Oil and gas annual reports:

http://www.pir.sa.gov.au/petroleum/legislation/company_annual_reports/cooper_and_eromanga_basins_annual_reports

South Australia—Environmental Protection Authority (EPA) air and water monitoring data:

http://www.epa.sa.gov.au/environmental_info/monitoring_data

## Inspections and Enforcement

### *Alberta*

Alberta—ERCB Field Surveillance and Operations Branch Provincial Summary (ST57):

http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_240_2547123_0_0_18/

Alberta—ERCB Monthly Enforcement Action Summary (ST108):

http://www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_308_265_0_43/http%3B/ercbContent/publishedcontent/publish/ercb_home/publications_catalogue/publications_available/serial_publications/st108.aspx

Alberta—Alberta Environment and Water Compliance Assessment Enforcement Reports:

http://environment.alberta.ca/01292.html

Alberta Environment and Water online oil sands portal (has enforcement data by project):

http://environment.alberta.ca/apps/osip/

### *Alaska*

Alaska—Inspection reports for large mines:

http://dnr.alaska.gov/mlw/mining/largemine/

Alaska—AOGCC Field Inspection Summary from 1980 to 2004:

http://www.doa.alaska.gov/ogc/annual/2004/2004_Inspections_Final.pdf

Alaska—EPA Inspections and Evaluations ECHO database (look up inspection data for each facility):

http://www.epa-echo.gov/echo/index.html

Alaska—EPA Compliance and Enforcement Annual Results for 2010:

http://www.epa.gov/compliance/resources/reports/endofyear/eoy2010/index.htmlAlaska—Alaska Oil & Gas Conservation Commission enforcement actions (listed as commission orders):

http://www.doa.alaska.gov/ogc/orders/como/otherindex.html

### *South Australia*

South Australia—Mining—*MESA Journal* annual reports (Volume 60 is 2010 annual review; volume 59 is 2009 annual review):

http://www.pir.sa.gov.au/minerals/publications_and_information/mesa_journals

South Australia—Implements policy and processes for mine closure using the Ministerial Council on Mineral and Petroleum Resources' (MCMPR) Strategic Framework for Mine Closure:

http://www.ret.gov.au/resources/mcmpr/Pages/StrategicFrameworks.aspx

South Australia—Oil and Gas Compliance reports:

http://www.pir.sa.gov.au/petroleum/legislation/compliance/petroleum_act_annual_compliance_report

## PART 3—MINE RECLAMATION AND FINANCIAL SECURITIES LINKS

## Reclamation

### *Alberta*

Alberta reclaimed land certificate online database:

http://environment.alberta.ca/01520.HTML

Alberta—Oil sands mines development and reclamation indicator:

http://environment.alberta.ca/02863.html

Alberta Environment and Water online oil sands portal (has financial securities and status of reclaimed land by project):

http://environment.alberta.ca/apps/osip/

*Alaska*

Alaska—DNR mining regulations; includes reclamation performance:

http://dnr.alaska.gov/mlw/mining/2009Reg_book.pdf

## Reclamation Security

*Alberta*

Alberta—Mine Financial Security Program details:

http://www.environment.alberta.ca/03388.html

Alberta—Current status of reclamation for oil sands lands:

http://environment.alberta.ca/02863.html

Alberta Financial Securities Data—Environmental Protection Security Fund Annual Report:

http://environment.alberta.ca/01874.html

*Alaska*

Alaska—Financial bonds and outstanding reclamation liabilities by mine:

http://dnr.alaska.gov/mlw/mining/largemine/

# Assessing Marine Transport for Oil Sands on Canada's West Coast

SPECIAL REPORT™

IHS

CERA

## About this report

**Purpose.** The growth of oil sands production has given rise to projects that could result in the expansion of exports of Canadian oil sands from Canada's West Coast. This has raised questions about Canada's ability to move oil sands crude safely by sea on this coast. What is the historical track record of moving crude oil by tanker? What risk management and safety measures are in place, and how does Canada compare to other jurisdictions?

**Context.** This is part of a series of reports from the IHS CERA Canadian Oil Sands 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. Participants include representatives from governments, regulators, oil companies, shipping companies, and nongovernmental organizations.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** The focus of the research was on ship-source oil spills. IHS CERA and IHS Maritime conducted our own extensive research and analysis, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Vancouver, British Columbia, on 21 March 2013 and participant feedback on a draft version of the report. IHS CERA has full editorial control over this report and is solely responsible for its contents (see end of report for a list of participants and the IHS team).

**Structure.** This report has an introduction, three main sections, and a conclusion followed by two annexes.

- Introduction
- Part 1: Tankers, incidents, and spills
- Part 2: Marine regulation, spill prevention measures, and application
- Part 3: Spill liability and compensation
- Conclusion
- Annexes A, B, and C: Details on international maritime governance, policy tools for maritime shipping safety and select IHS Maritime data.

# ASSESSING MARINE TRANSPORT FOR OIL SANDS ON CANADA'S WEST COAST

## KEY IMPLICATIONS

If new or expanded pipelines are built from Alberta to the coast of British Columbia, tanker movements on Canada's West Coast would increase. Although crude oil is the single largest commodity handled by maritime shipping in Canada, relatively few tankers currently call on the West Coast. The prospect of increased tanker activity has raised public concerns about the safety of shipping crude by sea and the risk of a large oil spill. This report provides facts and data with the aim of informing the debate surrounding increased tanker movements on Canada's West Coast.

- **What are the rules and measures for moving crude in Canada, and how do they compare with other jurisdictions?** The shipping industry is governed by international regulations that many nations, including Canada, have adopted. Consequently, the rules are generally similar across countries. However, the application of prevention and response measures, such as compulsory tug escorts, pilotage, and spill response plans and capabilities, can differ among countries, reflecting each nation's particular resources and needs.

- **Compared with 1989—the time of the *Exxon Valdez* spill—how has the tanker industry changed?** The industry has changed dramatically in the past 24 years. Improvements in tanker technology, operation, and enforcement have all contributed to fewer and smaller spills. Despite a near doubling of the global fleet, oil spill volumes over the past decade (2003 to 2012) were 75% lower than in the previous decade.

- **If a spill were to occur, how does compensation in Canada compare with that of other countries?** Although most nations have adopted the international regime (and, as a result, can access international funds), only a smaller subset (including Canada) participate in all levels of international funding. Canada has also established its own domestic compensation pool that operates in addition to international funds. In total, Canada can access up to C$1.3 billion per incident—exceeding what is available internationally.

- **If oil sands bitumen blends were to spill in the ocean, would they behave differently from other heavy crude oils?** Although experience is limited, there is insufficient evidence to conclude that oil sands bitumen blends would perform differently—sinking more rapidly than other crude oils of similar density. However, this is an area of active research; and if bitumen blends were found to perform differently, greater response capabilities (regarding the level of equipment and response timing) could be needed.

—June 2013

# ASSESSING MARINE TRANSPORT FOR OIL SANDS ON CANADA'S WEST COAST

## INTRODUCTION

Can Canada safely expand maritime oil exports, enhancing Canadian economic growth, while protecting the environment and local stakeholder interests? The purpose of this report, which is organized into three parts, is to shed more light on the three key questions that stakeholders are asking:

- What is the state of the global tanker industry?
- How does Canada compare with other nations in the regulation of maritime shipping and the level of prevention and response measures—particularly on its West Coast?
- In the event of a spill, who pays for cleanup?

The main text is followed by Annexes A, B, and C, which contain supporting information.

Canada has become the largest source of foreign oil to the United States over the past decade—3 million barrels per day (mbd) in 2012 compared with 1.4 mbd from the number two foreign supplier, Saudi Arabia.[1] This trend has made the oil industry an engine of economic activity and government revenue in Canada. But will the United States remain receptive to growing volumes of Canadian oil imports? This question has intensified owing to controversy in the United States over expansion of pipeline capacity between the two countries and highlights the risks of Canada's dependence on one market for its oil exports—a market that is past its peak in oil demand.

### WEST COAST ACCESS AND PRICING ISSUES

Below-market prices for Canadian crude—and the ensuing lost revenue—is another key reason that Canada wishes to build connections to the Asian oil market via the West Coast. In the past few years, rapid growth in US oil supply combined with oil sands growth has resulted in a crude oversupply and depressed prices for Canadian crudes.[2] If western Canadian producers had been able to bring their crude oils to the global market last year, they would have received about $14 more per barrel.[3] In 2012 alone, this equates to $15 billion in lost revenue.[4]

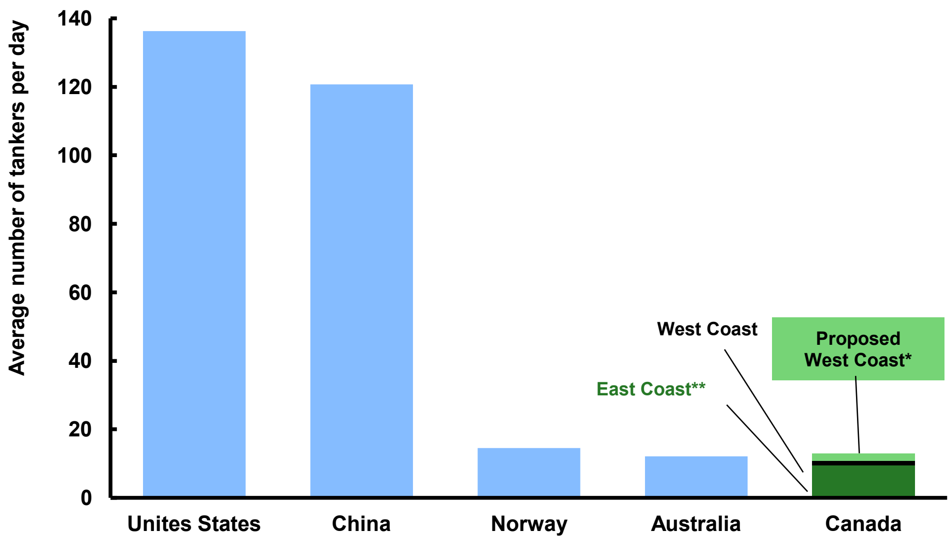
1. Source: US Energy Information Administration.
2. Between 2010 and 2012 supply from North American tight oil increased by 1.5 mbd.
3. Calculation based on a weighted average between 2012 light and heavy production from western Canada sourced from the National Energy Board www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/sttstc/crdlndptrlmprdct/stmtprdctn-eng.html and 2012 average Platts prices of $73 per barrel for Western Canadian Select (a western Canadian heavy crude), $100 per barrel for Mexican Maya (a globally traded heavy crude), $93 per barrel for synthetic crude oil (SCO) (a premium western Canadian light crude), and $112 per barrel for dated Brent (a globally traded light crude). Prices were adjusted for transport costs to the Gulf Coast of $10.50 per barrel for heavy and $8 per barrel for light crude.
4. Estimate based on 3 mbd of production and an average discount of $14 per barrel in 2012.

For these reasons, a number of new pipelines to bring oil sands (and other western Canadian crudes) to new markets have been announced. Two potential projects are targeting the fast-growing Asian market, with plan to transport western Canadian crudes though British Columbia to Canada's West Coast via pipeline, for export by tanker.

## CANADIAN TANKER ACTIVITY

Canada has extensive experience in moving crude oil by sea. Crude oil is the single largest commodity moved by ship in Canada and accounts for one-third of all cargo handled.[1] However, as shown in Figure 1, compared with some jurisdictions, Canada's activity is fairly modest—particularly on the West Coast, where only 9% of all tanker traffic occurs.[2,3]

**Figure 1**
**Average daily tanker traffic in select countries**
(average port calls of tankers in 2012 and proposed movements associated with West Coast export projects*)




Source: IHS Maritime.
Note: Data shown are port calls--a shipping arriving, berthing, and sailing is counted as one call. This includes tankers ranging from coastal/handysize through to ultralarge crude carriers.
*Proposed movements include those associated with the Northern Gateway Pipeline Project and the Trans Mountain Pipeline Expansion project. See the text box "Primer: Canadian oil sands, tankers, West Coast export pipelines."
**East Coast includes movements on the Canadian East Coast and St. Lawerence. Movements in the Great Lakes are not shown.

1. Based on volume of crude oil loaded and unloaded as reported by Statistics Canada, "Shipping in Canada, 2011," Tables 15-1 and 15-2, http://www.statcan.gc.ca/pub/54-205-x/54-205-x2011000-eng.htm.
2. For geographic reasons Canada's primary experience with moving oil by sea has been from offshore production (e.g., Hibernia) and the export (including re-export) and import of crude oil and movement of refined products on Canada's East Coast. Much smaller quantities of oil movements occur on the West Coast, where most oil transport is for refined products such as heating, power generation, and transport fuels in coastal communities.
3. Comparison made here is based on movement data provided by IHS Maritime and includes tanker traffic shown in Figure 1 plus an additional 1,362 movements that occurred in the Great Lakes in 2012. "Traffic" is defined here as port callings—a ship arriving, berthing, and sailing is counted as one call. This includes tankers ranging from coastal/handysize through to the largest of tankers. For more information see Table C-1 in Appendix C. On a volumetric basis, as measured by Statistics Canada, 15% of all crude oil handled in Canada is on the West Coast. Statistics Canada, "Shipping in Canada 2011," http://www.statcan.gc.ca/pub/54-205-x/2011000/part-partie1-eng.htm, accessed 23 May 2013.

Although the transport of crude oil by sea is less familiar on Canada's West Coast, maritime shipping in general is not. The Port of Metro Vancouver is the busiest port in the country, accounting for over one-fifth of all cargo loaded and unloaded.[1] If constructed, the proposed projects would more than double tanker activity on Canada's West Coast (see Figure 1).

See the box "Primer: Canadian oil sands, tankers, and West Coast export pipelines" for an explanation of the crude oil and tanker terms and the proposed export projects discussed in this report.

**Primer: Canadian oil sands, tankers, and West Coast export pipelines**

**Canadian oil sands**

In its natural state, raw bitumen is solid at room temperature and cannot be transported in pipelines. To be transported by pipeline, bitumen must be either diluted with light oil into a bitumen blend or converted into a light crude oil, called synthetic crude oil (SCO).

- **SCO.** SCO is produced by upgrading bitumen (either by removing carbon or adding hydrogen) from a heavy crude oil into a lighter crude oil. SCO resembles light, sweet crude oil, typically with a density less than 876 kilograms (kg) per cubic meter (or an API gravity greater than 30°).
- **Bitumen blends.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. The blend density is between 923 and 940 kg per cubic meter (20–22°API), making it comparable to other heavy crudes, such as Mexican Maya. A common bitumen blend is dilbit—short for diluted bitumen—which is typically about 70% bitumen and 30% lighter hydrocarbons.

**Crude oil tankers**

Crude oil is transported by vessels ranging from small barges to very large crude carriers (VLCCs) that can span over three football fields (about 274 meters) in length and carry over 2 million barrels of oil. The size of a tanker is generally reflective of its intended use; larger ships tend to be engaged in long-distance voyages, whereas smaller vessels are typically used in shorter voyages (and often with a more diverse range of cargo, such as refined products). Tankers are a subset of the global shipping fleet. In 2012 the entire shipping fleet consisted of about 58,800 vessels, with tankers accounting for about one-fifth (not including barges), or about 10,400 vessels.[1] Collectively, the total capacity of the global tanker fleet is about 4.2 billion barrels (or 568 million metric tons [mt])—roughly double that of 20 years ago.[2] Nearly two-thirds of total tanker capacity is held by large tankers (Aframax size and up).

Crude carriers are classified by both weight and dimension. For simplicity, this report uses two terms for classifying vessel size: small tanker for Panamax class and smaller and large tanker for Aframax class and larger. The focus of this report is on large tankers. Table 1 presents the ship classifications and the terms used in this report.

**West Coast export pipeline projects**

Two pipeline projects have been proposed. Collectively, they would increase the movement of oil along Canada's West Coast by about 1.3 mbd.

1. Source: IHS Maritime. This includes ships with a capacity greater than 10,000 metric tons for bunkering, chemical/products, crude oil, crude products, refined products, shuttles, and unspecified tankers.
2. In 1992 the global fleet had about 6,400 tankers with a combined capacity of just over 2 billion barrels (274 mt).

1. Statistics Canada, "Shipping in Canada 2011," Table 13, http://www.statcan.gc.ca/pub/54-205-x/54-205-x2011000-eng.htm.

**Primer: Canadian oil sands, tankers, and West Coast export pipelines (continued)**

- **The Northern Gateway Pipeline.** This project would involve the construction of two pipelines from Alberta to the Port of Kitimat, British Columbia. The first line would have export capacity of up to 525,000 barrels per day (bd) of crude oil, and the second line could import up to 192,000 bd of condensate—a necessary component in some bitumen blends. The project would result in about 220 tankers of different sizes calling on the Port of Kitimat annually and includes the capability to handle VLCCs. The Northern Gateway project is advanced in the Canadian regulatory process, and a decision is expected following the review process at the end of 2013.* If approved, the project could be shipping crude oil by 2018.

- **The Trans Mountain Expansion.** This project would expand the capacity of the existing Trans Mountain Pipeline that runs from Alberta to the Port of Metro Vancouver, British Columbia, from 300,000 bd today to 890,000 bd. Currently Trans Mountain loads about 60 tankers (a mix of Panamax and Aframax) and 36 crude and refined product barges per year. The proposed expansion would result in about 348 new tankers per year calling on the Port of Metro Vancouver; these would be up to partially loaded Aframax size vessels (navigational restrictions limit the cargo capacity to approximately 550,000 barrels (80,000 MT).[3] There are four other petroleum terminals in the Port of Metro Vancouver, all operated by oil companies; most traffic associated with these other terminals is barge traffic, with some limited tanker activity. The Trans Mountain Expansion project is still in the early stages and will become known when the permitting application is filed (scheduled for 2014). If approved, the project could be shipping crude oil at full capacity by 2018.

3. Final decision will be made by the Government of Canada following the Joint Panel Review report.
Vessel draft limitations for ships accessing the oil terminals in the Port of Metro Vancouver would limit how much a tanker may be loaded in this port. Source: Application for Pipeline Certification for the Trans Mountain Expansion Project to the National Energy Board. Trans Mountain Pipeline, Project Description, Section 2, page 14, May 23, 2013; https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=956916&objAction=browse, accessed 4 June 2013.

**Table 1**

**Tanker classifications**

| Term used for this report | Class | Weight (metric tons) | Capacity (barrels)[1] | Number of ships[2] | Collective capacity of fleet (million tons)[2] |
|---|---|---|---|---|---|
| Small tankers | Panamax and smaller[3] | less than 80,000 | less than 600,000 | 8,550 | 222 |
| Large tankers | Aframax | 80,000–120,000 | 600,000–900,000 | 880 | 100 |
| | Suezmax | 120,000–200,000 | 900,000–1,500,000 | 420 | 73 |
| | Very large crude carrier (VLCC)[4] | 200,000–320,000 | 1,500,000–2,400,000 | 550 | 173 |

Source: IHS Maritime.
1. Tanker carrying capacity in barrels would vary depending on the density of crude oil. Unless otherwise stated, in this report capacity estimates are based upon crude oil density of 845 kg per cubic meter (or API gravity of 36 degrees).
2. Approximate values. Actual value may differ owing to rounding.
3. Panamax vessels range from 55,000 to 80,000 dwt. Smaller ships include Handysize which range from 10,000 to 55,000 dwt.
4. In addition to the VLCC, a larger class of vessel exists, the ultralarge crude carrier. They are not included here as they are not contemplated for any export project on the West Coast and there are fewer than 30 in operation globally.

## PART 1: TANKERS, INCIDENTS, AND SPILLS

With the prospect of increased tanker activity on the West Coast of Canada, the risk of a large spill, such as occurred with the *Exxon Valdez,* remains central to public concerns. However, tanker operations have improved dramatically since 1989, resulting in a decrease in both the frequency and the volume of spills over time.

### INCIDENTS DON'T ALWAYS CAUSE SPILLS

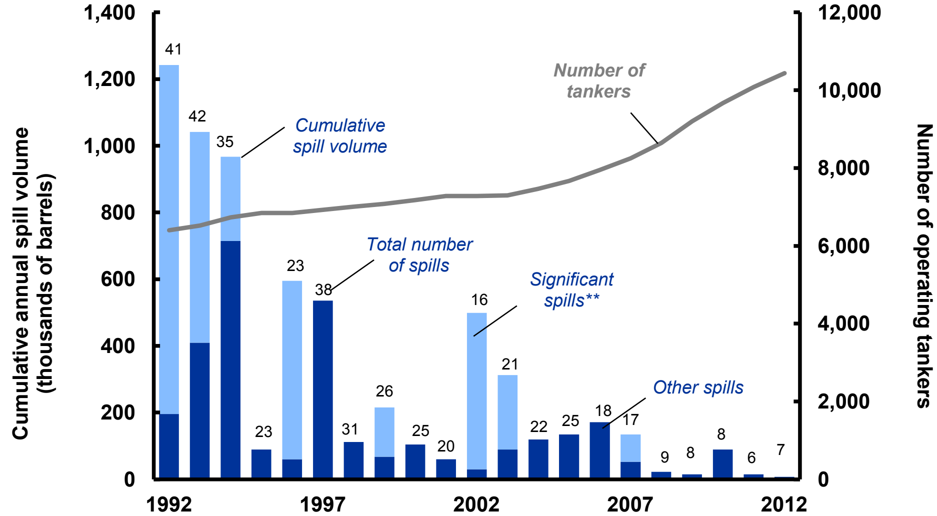
IHS Maritime maintains a registry of global "incidents" which covers a wide range of events that can be as minor as removing a tanker from service for a few hours to repair an engine or as major as a grounding or fire that could lead to an oil spill. In the past 10 years, the vast majority of incidents (94%) involving large tankers have not resulted in a spill.[1] And when spills have occurred, most are small. Globally over the past decade, reported spills have averaged about 7,200 barrels per incident (about 971 mt).[2] Most incidents occur at sea, with machinery failure (such as a loss in power) being the most common direct cause. When incidents occur closer to land (in coastal waters or in port), the potential for a collision with other objects or vessels is greater. Consequently, near-shore incidents are more likely to result in an oil spill. This explains why most prevention and response capabilities are located closer to shore. For more IHS Maritime information on global tanker incidents and spills, both cause and location, see Annex B.

### RATE AND FREQUENCY OF TANKER OIL SPILLS DECLINING

Despite growth in the overall global tanker fleet, most oil spills are small and overall spill frequency and volume have decreased over time (see Figure 2). Spills from large tankers (the kind of ships proposed for Canada's West Coast) are even less frequent, with no spills reported in the past two years.[3] According to the International Tankers Owners Pollution Federation (ITOPF), the decline in the number and size of spills is part of a long-term trend dating back to the 1970s. On average, spill volumes over the past decade (2003 to 2012) fell by 75% in comparison with levels the decade prior (1993 to 2002).[4] Volumes continued to decline over the past decade, falling by 87% in the past five years compared with the previous five years. Last year, 2012, was the lowest in ITOPF's database, with less than 7,500 barrels (1,000 mt) spilled.[5] When a large spill occurs, it can account for a majority of the spill volume for that year. The last major spill globally was in 2007, when

1. Source: IHS Maritime.
2. From 2003 to 2012 over 1 million barrels (137,000 mt) were reported spilled in 141 incidents. Source: ITOPF (2012), "Oil Tanker Spill Statistics," www.itopf.com/information-services/data-and-statistics/statistics/documents/StatsPack_001.pdf, accessed 8 April 2013.
3. Source: IHS Maritime.
4. Spill volumes averaged 421,000 barrels (56,700 mt) per year for the decade from 1993 to 2002 versus an average of 102,000 barrels (13,700 MT) per year from 2003 to 2012. Source: ITOPF (2012).
5. Source: ITOPF (2012), "Oil Tanker Spill Statistics," www.itopf.com/information-services/data-and-statistics/statistics/documents/StatsPack_001.pdf, accessed 8 April 2013.

**Figure 2**
**Global frequency and volume of spills from tankers***




Sources: IHS Maritime, ITOPF, and various sources.
*Spill data include accidental spills of oil from all sizes of tankers carriers and barges. For more information see www.itopf.com.
**Significant spills are spills originating from only one or two vessel. In order, significant spills over the period shown in this figure include the Aegean Sea and the *Katina P* (1992), the *Braer* (1993), the *Morris J. Berman* (1994), the *Sea Empress* (1996), the *Erika* (1999), the *Prestige* (2002), and the *Hebei Spirit* (2007).

the *Hebei Spirit* spilled 82,000 barrels (10,900 mt) near the Port of Daesan on the West Coast of South Korea.[1]

## TRANSFORMATION OF THE SHIPPING INDUSTRY COMPARED WITH 1989

On Canada's West Coast the 1989 *Exxon Valdez* incident is often cited as an example of the risk that tankers can pose and the extent of the damage that can result from a spill. Since then, however, technology and regulation have transformed the shipping industry.

The probability of this type of accident—a powered grounding owing to navigational error—is less likely today. Improvements in tanker technology and in tanker operations—including requirements crew competency; fatigue management; the use of pilots and tugs; improved navigational systems, including radar, global positioning systems, and use of electronic charts; and increased vigilance through monitoring and enforcement—have helped to reduce the risk of an oil spill. Spill response planning has also evolved. Risk analysis, scenario planning, simulations for training pilots and crew, and drills are often used to help responders to prepare for a potential spill. Many of changes are explained in Part 2, which reviews Canada's spill prevention measures and application.

1. The *Hebei Spirit* was a large single-hull tanker. On 7 December 2007, it anchored about 5 nautical miles off the west coast of South Korea, near the Port of Daesan when it was struck by a crane barge on its port side. At the time the *Hebei Spirit* was loaded with over 1 million barrels of crude oil [209,000 mt]. The collision punctured three of the vessels port cargo tanks, spilling an estimated 82,000 barrels [or 10,900 mt.] Source: IHS Maritime, International Oil Pollution Compensation (IOPC), "Incidents," *Hebei Spirit* cast study, http://www.iopcfunds.org/incidents/incident-map/#2007-185-December – accessed 11 June 2013.

One example of technical advancement is the adoption of double-hull tankers.[1] Twenty years ago, single-hull tankers accounted for 93% of large tankers globally.[2] Since 2010, all large tankers operating in international crude trade must be double hulled.[3] According to the International Maritime Organization (IMO), had double-hull vessels been used historically, up to 85% of spills could have been prevented.[4] Double-hull tankers are not risk free, however: if improperly maintained, they can be more susceptible to internal corrosion, highlighting the importance of proper vessel vetting and inspections. However, it is widely accepted that the benefits of a double hull outweigh these risks.[5] Other notable technological improvements include segregated cargo tanks to mitigate outflow in the event of a collision or grounding (consequently if both hulls were breached, the segregated tanker could limited the volume spilled to that contained in the section breached); corrosion coatings for cargo and ballast tanks (to reduce the risk of corrosion and hull failure); and minimum design requirements (such as rules for construction of tankers and inspections).

Modern tanker operations bear little resemblance to the fleet of 24 years ago. Despite a nearly doubling of the global tanker fleet, both the rate and volume of spills have declined owing to improvements in tanker technology, design, and operations.

1. Double-hull tankers, as defined by IHS Maritime, are tankers in which the bottom and sides of the cargo tanks are separated from the bottom and sides of the hull by void spaces. These spaces carry the seawater ballast when required.
2. Source: IHS Maritime.
3. As of 2012, only 2% of large tankers were single hulled. The few remaining single hulls are believed to be engaged in trades other than the international transport of crude oil (e.g., in storage or in coastal operations in nations that haven't banned single hulls). Any of the remaining internationally operated single-hull tankers will be phased out by 2015. (Source: IHS Maritime.)
4. IMO (1992), "IMO Comparative Study on Oil Tanker Design," Marine Environmental Protection Committee, Session 32, Agenda Item 7 (MEPC/32/7/15), London, United Kingdom.
5. Source: Oil Companies International Marine Forum (OCIMF) (2003), Double Hull Tankers—Are they the answer?

# PART 2: MARINE REGULATION, SPILL PREVENTION MEASURES, AND APPLICATION

Crude oil is the single largest commodity handled by maritime shipping in Canada. Most of this occurs on the East Coast, and the transport of oil by sea is less common on Canada's West Coast. Increased traffic will increase the statistical risk of a spill. In this context, questions are being asked about Canada's experience and how Canada's management, prevention, and response regime compares to that of other nations.

Our research found that the international nature of maritime shipping has led to regulatory consistency across many nations, including Canada. However, subtle differences can emerge in how nations choose to apply these rules, often reflecting the resources and needs (economic, social, and environmental) of each country. In this context, if West Coast oil exports increase, Canada's level of prevention and response should be expected to rise. This expectation is already evident, with the Government of Canada appointing an expert panel to review and make recommendations on how to improve Canada's regime.[1]

This part is divided into three sections: key principles of Canadian maritime regulation; Canadian oil spill prevention measures; and examples of how Canada, Australia, Norway, and the United States compare in applying these measures.

## REGULATION OF SHIPPING: CANADA FOLLOWS INTERNATIONAL STANDARDS

Canada's maritime shipping is a highly regulated industry. Canada has chosen to follow and participate in a number of international agreements and conventions that help establish the rules for maritime shipping globally. Because of this, the rules in Canada tend to be similar to other jurisdictions'.

Because ships spend their economic lives going to and from different jurisdictions, the international community cooperated in establishing international bodies, agreements, and conventions that collectively govern the industry. Although nations can establish their own rules, and many do, the decision to establish unique rules must be balanced with a country's ability to enforce them and its own trade interests. For instance, if a country imposes unique and costly shipping requirements, this could create barriers to trade. An example of a unique rule would be an outright ban on tankers, as some have suggested for Canada's West Coast. However, no other country has chosen this approach to manage risk from tankers.

The IMO, a division of the United Nations, is the central organization in charge of establishing international rules and guidelines for the shipping industry. When countries are in agreement with an IMO convention, they choose to become a signatory to the convention. Next, a country must incorporate the regulations into its own domestic laws and enforcement. Collectively, when enough countries have both signed a specific convention and incorporated the rule into domestic law, the protocol becomes internationally accepted—and becomes a rule.

1. Transport Canada, http://www.tc.gc.ca/eng/mediaroom/releases-2013-h031e-7089.htm.

Canada is a member of the IMO and participates in the development of international conventions. In Canada, the federal government has jurisdiction over shipping and the waters out to 200 nautical miles.[1] When Canada adopts an international convention, it is generally incorporated into the Canadian Shipping Act, but other legislation can be affected. Transport Canada is the principal federal department in charge of enforcing shipping rules in Canada. Other departments, such as the Department of Fisheries and Oceans, which includes the Canadian Coast Guard (CCG) and Environment Canada, also have important roles in ensuring safe and secure waterways and protecting the environment.

For more details on Canadian maritime shipping regulation and specific acts and regulations, see Annexes A and B.

## SPILL PREVENTION MEASURES: CANADA IS SIMILAR TO OTHERS

Canada's measures to improve ship safety and prevent incidents and spills tend to be similar to those of other nations owing to the common adoption of international conventions and industry best practices.[2] The following section highlights some key measures promulgated in Canada and imposed by industry to prevent and respond to oil spills.

### Canadian measures and regulations

- **Ship design and crew competencies.** International agreements prescribe tanker construction (including for double hulls) and other equipment.[3] Other conventions address human factors such as crew competencies, crew fatigue, and safety planning.[4]

- **Inspections.** Port state control enables Canadian authorities to board, inspect, and enforce regulations on foreign ships.[5] Canadian regulators conduct more than 1,300 foreign ship inspections each year. If a serious problem is found, enforcement tools include warnings, fines, vessel detention, and prosecution.[6]

- **Vessel traffic services and aids to navigation.** Transport Canada, the Department of Fisheries and Oceans (which includes the CCG), and Environment Canada all have roles to play in providing ships transiting Canadian waters aids to navigation, vessel identification and communications services, rules for transiting high traffic areas, and

1. Under the Constitution Act, 1867, the federal government has exclusive jurisdiction over shipping and the waters out to 200 nautical miles (though Canada's rights diminish beyond 12 nautical miles offshore; for more information see Annex A).
2. Since the potential damages from a spill can be large, industry practice often exceeds regulatory requirements. Some industry measures stem from requirements of insurance and other underwriters, and their activities can be part a self-assessment process or a requirement for compliance with terminals.
3. The International Convention on the Prevention of Pollution from Ships (MARPOL) requires double-hull tankers. The Safety of Life at Sea Convention (SOLAS) includes many other requirements for construction and equipment.
4. The International Convention on Standards of Training, Certification and Watchkeeping for Seafarers established crew competencies and 1995 amendments to help prevent fatigue. International Safety Management Code (ISM Code) established requirements for safe management for pollution prevention.
5. Transport Canada Marine Safety Directorate administers the Canada Shipping Act 2001 and other federal statutes that govern port state control. These regimes enable foreign flagged vessels to be inspected for compliance with international requirements (e.g., MARPOL and SOLAS) and those of the nation where the vessel is registered.
6. Source: Transport Canada, Enbridge Northern Gateway Project Joint Review Panel submission, December 22, 2012, accessed 17 April 2013, www.neb-one.gc.ca/fetch.asp?language=E&ID=A2K4S4.

weather reports.[1] Ships transiting Canadian waters are required to make use of specific Canadian navigational services.[2] On the West Coast, Canada requires all vessels of greater than 300 metric tons on an international voyage to have Automatic Identification Systems (AIS), which broadcasts detailed information such as ship identity, type, position, course, speed, and status to other vessels and ground receiver stations.[3] Services like AIS aid in vessel navigation around ships and other obstacles.[4]

- **Compulsory marine pilotage.** Pilots board ships at the entrance to sensitive or navigationally challenging areas to provide local navigational assistance to the master of a vessel.[5] Pilots are all experienced mariners with hundreds to thousands of days operating in the waters they pilot; they are well versed in local navigation hazards, currents, and weather patterns.[6] According to the Canadian Marine Pilots Association, Canadian pilots have consistently achieved an incident-free rate of 99.9%.[7] On Canada's West Coast, pilots are required over a large area—roughly 2 miles out from the entire coast and in all major channels and fjords. A minimum of two pilots would be required aboard full (or laden) tankers.[8]

- **Escort tugs.** In Canada, tug escorts are typically a requirement of local authorities (pilotage authority or other safety authority risk assessments, port authority, or marine terminal operating procedures). Tugs help maneuver vessels, control course, and influence speed. The number of tugs used depends on several elements: regulatory requirement, weather, size of the tanker, size and power of the tug, and navigational hazards. On the West Coast, the Port of Metro Vancouver requires full (or laden) tankers to have escort tugs. Under the proposed conditions for the Northern Gateway, escort tugs will

1. Through various government departments the Government of Canada provides a range of navigational safety services. These can include communications services (e.g., radio contacts, navigation information and assistance, distress and safety communications, emergency response services); traffic services (e.g., enhanced global positioning systems [differential GPS], automatic identification systems [AIS]); nautical and waterway information [such as charts, water depth, tides, currents, and sailing directions]); and icebreaking, to name a few.
2. Under Charts and Nautical Publications Regulations, of the Canada Shipping Act (1995), mariners must have onboard and use the most recent edition of charts (for the areas to be navigated) and other required documents and publications when in Canadian waters. These requirements include the appropriate charts, Sailing Directions, and Tide/Current tables, as published by the Canadian Hydrographic Services, and Notice to Mariners; Radio Aids to Marine Navigation; and List of Lights, Buoys and Fog Signals, as published by the Department of Fisheries and Oceans.
3. This rule excludes fishing vessels; and if a ship has more than 12 passengers, the threshold is reduced to 150 mt. In addition to ground receivers, satellites can also be used to receive AIS signals. This can make AIS tracking potentially limitless. IHS Maritime, which manages a global AIS database, is capable of tracking about 90% of the global shipping fleet. The 10% remainder may represent vessels temporarily out of service for maintenance.
4. AIS is still not widely used on smaller vessels (fishing and recreational vessels). Although these vessels pose little direct risk to large tankers, they can influence their navigation, which could result in an incident.
5. The federal Pilotage Act mandates compulsory pilotage.
6. Specific requirements may vary by jurisdiction, and different types of experience are considered. All pilots must have specific levels of certification and pass specific tests to be qualified as a pilot. For more information on the requirements for pilots on Canada's West Coast, see http://www.ppa.gc.ca/text/documents/How_to_become_a_pilot.pdf, accessed 16 May 2013.
7. Source: Canadian Marine Pilots Association, http://www.marinepilots.ca/en/the-canadian-system.html, accessed 16 May 2013.
8. This includes tankers calling on the Port of Metro Vancouver as well as a proposed condition of the Joint Review Panel for the Enbridge Northern Gateway Project. Source: Northern Gateway Joint Review Panel, www.neb-one.gc.ca/fetch.asp?language=E&ID=A2K4S4, accessed 17 April 2013.

also be required, including for empty tankers (or under ballast).[1] The requirement for escort tugs provides added security, even when the tanker is outside of the defined escort zone, because it provides a fleet of tugs that are generally stationed nearby in case of an emergency.

- **Oil spill response plans and capabilities.** Canada has signed onto international agreements for oil spill preparedness which mandate that ships entering Canadian waters have oil pollution emergency plans and report oil spills.[2] Tankers are obligated to have response equipment on hand and must actively plan and practice for a spill. In Canada, all tankers and terminals are required to have oil spill response plans as well as a contract with a certified response organization that is prepared to respond to ship or terminal oil spills.[3,4] Private response organizations are certified by Transport Canada and must demonstrate their ability to prepare and respond to marine oil spills. On the West Coast, the Western Canada Marine Response Corporation (WCMRC) is the certified private response organization.
- **Aerial surveillance.** Canada's National Aerial Surveillance Program patrols the coastal region. Air inspection does not prevent spills but is an important tool in deterring illegal activities, including discharges of oil and other waste—a concern not limited to tankers. Aerial surveillance also helps with early detection of marine pollution, which aids in rapid response to a spill.

In addition to these measures, Canada can also require crew standards, safety management procedures, places of refuge for vessels in distress, and special routing measure and waste control measures to protect environmentally sensitive areas. Many of these topics are included in Annex B: Key policy tools for safety of maritime shipping.

In addition to following the rules and measures from Canadian authorities, the shipping industry frequently adopts additional practices to enhance safety:

- **Industry collaboration.** There are numerous examples of industry collaboration aimed at reducing spill risk. The Oil Companies International Marine Forum (OCIMF), representing 93 oil companies, has created its own tools and standards for preventing oil spills. For instance, companies inspect tankers they hire and share inspection

1. Canada Shipping Act, 2001 does not mandate escort tugs. For the Northern Gateway one tug escort is proposed for when the tanker is empty (or under ballast) and two (one being tethered) when it is full (or laden). National Energy Board, Potential Panel Conditions, Attachment B—Collection of potential conditions, page 5, April 12, 2013, https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=942629&objAction=browse&redirect=3, accessed 23 May 2013.
2. International Convention on Oil Pollution Preparedness, Response and Co-operations.
3. The prevention and control of ship-source pollution is governed by the Canada Shipping Act, 2001 and the Arctic Waters Pollution Prevention Act, 1985. To operate in Canadian waters, all tankers greater than 150 mt and all other vessels of more than 400 mt must carry an approved shipboard oil pollution emergency plan. Terminals are required to have oil pollution emergency plans. Under the proposed Safeguarding Canada's Seas and Skies Act, terminal plans will have to be approved by Transport Canada. Source: Transport Canada, 2013 Media Backgrounder, "World-Class Tanker Safety System: Amendments to the Canada Shipping Act, 2001 (Safeguarding Canada's Seas and Skies Act)," http://www.tc.gc.ca/eng/mediaroom/backgrounders-menu-7087.htm, accessed 17 May 2013.
4. In the event of a spill, the polluter is not obligated to use the response organization if the polluter is capable of handling the spill itself, and the response organization is not mandated to respond unless it is under contract to the responsible party or direction of the CCG.

results.[1] Most oil companies require a recent inspection—in some cases in the past six months or less—to hire a tanker. OCIMF also trains inspectors and publishes safety standards for oil tankers and terminals.[2] Governments may also access inspection data. Shipowners also have an industry organization, ITOPF, as discussed in Part 1. ITOPF has an experienced response team to assist in the case of an oil spill; it also provides training and spill response planning services. In collaboration with IMO, ITOPF, and others, the International Petroleum Industry Environmental Conservation Association, which represents both upstream and downstream oil and gas companies, promotes best practice and oil spill capabilities around the world.

- **Tanker requirements.** When hiring a vessel, oil companies often stipulate its maximum age; the limit typically ranges between 15 and 20 years. Although double hulls for large tankers were not required by regulation until 2010, many oil terminal operators required double hulls earlier. Prior to employing a vessel, operators are screened for their operational practices, including safety and risk management procedures as well as crew experience and knowledge.

- **Pilotage and terminal loading/unloading requirements.** In addition to government mandated pilotage, terminal operators often have their own pilots for tankers entering oil terminals. Often personnel from oil terminals supervise tanker loading and unloading to ensure that it follows best practice.

## APPLICATION OF SPILL RESPONSE MEASURES: SUBTLE DIFFERENCES EMERGE

Although there is great uniformity in spill response measures across jurisdictions, their application and enforcement are influenced by domestic programs and by local factors (e.g., traffic levels, weather, navigational conditions, and financial resources).

For some aspects of spill response and preparation, divergence in the application of oil spill preparedness measures is not necessarily an indication of one country's prudence over another. Rather, it is likely due to local conditions. What is practical in one location could be deemed inappropriate or imprudent in another.

This section compares specific illustrative examples of oil spill prevention and response in Canada to Norway, the United States, and Australia, which are often perceived as leaders in this area. To be sure, this analysis is not a comprehensive list of all aspects of oil spill prevention and response. We acknowledge that comparisons are a challenge, but this research helps to provide further context for the type of activities that are undertaken to prevent and respond to oil spills among countries.

- Response authority and leadership
- Response planning and exercising
- Use of risk assessment tools

1. The OCIMF provides a standardized database of ship inspection reports, known as the Ship Inspection Report Program (SIRE). Although not all tankers are included in the database, as of 2010 the database included 7,737 vessels.
2. OCIMF, International Safety Guide for Oil Tankers and Terminals, 5th Edition 2006.

- Response equipment and requirements
- Funding

## Response authority and leadership

Rapid spill response requires strong leadership, fast decision making, and the ability to gather and disseminate information quickly. All jurisdictions require the polluter to cover the costs of an oil spill (called the "polluter pays principle"). However, how they organize the response varies. Comparing current practice in Canada to others, authorities in other jurisdictions seem to exert greater ability in taking over response efforts (if the polluter is unable, unwilling, or judged to be doing an unsatisfactory job) and in exerting resources (intervention powers, cleanup equipment, and/or funding) if required. In a crisis, any response delay could worsen the ultimate outcome. It is unclear whether Canada's model would slow response and be a detriment; ultimately Canadian authorities (such as the CCG) have powers similar to those of the United States to seize control (see the box "Response, authority, and leadership").

### Response, authority, and leadership

**Canada.** In Canada, an industry and government partnership organizes oil spill response and relies on third-party organizations to clean up spilled oil. The CCG is the lead government agency responsible for ship-sourced pollution. In some ports, agreements may be in place that give the port authority a greater role to manage the response. Historically, the CCG has taken a monitoring role, putting the onus on the polluter to respond and appoint an on-scene commander. Private response organizations, such as the WCMRC, may execute the oil spill cleanup on behalf of the polluter. The CCG can take command if the polluter is unwilling or unable to respond or if the source of the spill is unknown. CCG also maintains its own oil spill response equipment in approximately 80 sites throughout Canada (about 14 on the West Coast).[1]

**United States.** As in Canada, the polluter is responsible for cleaning up oil spills using third-party organizations. However, unlike Canada's current system the cleanup is conducted under the leadership of a federal government on-scene coordinator. If the on-scene coordinator deems the polluter's actions as insufficient, the coordinator has the authority to take over and can use federal resources to respond if needed.

**Australia.** The Australian Maritime Safety Authority, a federal agency that is principally self-funded, is responsible for responding to oil spills from ships—providing both cleanup and leadership. If a spill occurs more than 3 nautical miles offshore, a single national decision maker—the Maritime Emergency Response Commander—is appointed to coordinate the response. If a spill is closer to shore and local governments are able to respond, they lead the effort. For the Great Barrier Reef, the state government has the main responsibility. The spill response leader is granted intervention powers and can take all necessary measures to reduce the impacts from an oil spill.

**Norway.** While the onus is on the polluter to pay for the cleanup, the Norwegian Coastal Administration (a federal agency) is responsible for leading the clean-up of oil spills from ships and has powers to draw upon all available resources in Norway. For spills from offshore oil wells (Norway has a large offshore oil production industry), oil companies (not the federal government) are expected to lead.

1. Source: CCG, Marine Spills Contingency Plans, Preparedness, http://www.ccg-gcc.gc.ca/eng/Ccg/er_National_Response_Plan/s3, accessed 17 May 2013.

## Planning and exercising

All jurisdictions reviewed have prepared national, regional, vessel, and some port specific plans for managing the response to an oil spill, and they conduct exercises of these plans. Comparing the rigor of exercises among locations is a challenge because information on the scope and frequency of drills is limited. Canada, like the United States, does not have a systematic process for updating its national response plan (see the box "Planning and exercising").

### Planning and exercising

**Canada.** Canada has both national and regional oil spill response plans and conducts exercises of its plans on an ongoing basis. There is no regimented requirement for refreshing Canada's national response plan. Although the current plan was updated recently (in 2011), the vintage of the age of the prior plan had elicited criticism.[1] One example of a response exercise on the West Coast is the US and Canadian annual joint spill response exercise. Private response organizations are certified every three years to ensure that they can meet requirements, and oil terminal operators must conduct spill response exercises.

**United States.** As in other jurisdictions, each tanker in US waters is required to have an oil spill response plan. However, the United States imposes a more stringent requirement than most other countries: that the ship's plan consider the worst-case scenario of a loss of the entire cargo. The US national oil spill response plan, the National Contingency Plan (NCP), was last updated in 1994. In addition, regional and area contingency plans are required. In early 2013 the US Environmental Protection Agency (EPA) recommended that the regional and area plans along with the national plan be updated to account for technology and communication changes since 1994.[2] The NCP requires practice exercises. At the national level, the United States has guidelines for the frequency and scope of exercises. For instance, about every three years the United States Coast Guard (USCG) conducts a significant national exercise. Exercises are also conducted at the regional level, and industry is also required to conduct exercises.

**Australia.** At the national level, Australia's oil spill response plan was last updated in 2011.[3] Australia's national plan is a cooperative effort among federal, state, and territorial governments; local emergency responders; and industry. About every 10 years there is a complete review of the oil spill plan, including the risk assessment fundamentals. Australia conducts national exercises every two years to test the administrative and operational effectiveness of the spill response plan.

**Norway.** Norway has a national oil spill contingency plan as well as municipal government and private contingency plans. Several large integrated exercises are conducted annually.

1. Marine Spills Contingency Plan—National Chapter (2011) replaced the Marine Spills Contingency Plan—National Chapter (1998). In 2010 the Commissioner of the Environment and Sustainable Development released an audit, finding that the national plan dated back to 1998 and the Pacific Region's oil spill plan dated back to 2001. The 2010 report was titled Oil Spills from Ships Emergency Management Plan.
2. Source http://www.epa.gov/oig/reports/2013/20130215-13-P-0152.pdf, accessed 6 April 2013.
3. National Maritime Oil Spill Contingency Plan 2011.

## Use of risk assessment tools

Risk management tools provide information on the potential risks and outcomes of an oil spill. Insights learned can be used to inform oil spill response plans. Risk assessment tools are used in Canada, but not as systematically as in other nations included in our analysis.[1] However, a national tanker traffic risk assessment study is now under way in Canada (see the box "Use of risk assessment tools").

### Use of risk assessment tools

**Canada.** Until recently, risk assessment tools have been used primarily in the environmental review of new projects and in some regional examples. For instance, in 2007 Canada completed a risk assessment for the south coast of Newfoundland and subsequently adjusted the regional oil spill response plan.[1] Less recently, Transport Canada conducted a risk assessment for oil transport on the West Coast of Canada in 2002, and the CCG conducted a risk assessment of response capacity in Canada in 2000 and an update on the probability of oil spills from tankers in 2002.[2] Canada is now undertaking a national risk assessment for marine spills.[3] The completed national study is expected to provide an updated view of the risks and spill scenarios that should be considered in national and regional oil spill response plans.

**United States.** The USCG uses risk assessments in oil spill response planning and has institutionalized models and tools to support this process. Unlike those in other jurisdictions, however, the US spill response plans must meet the regulatory requirement of preparing for a worst-case scenario. Oil spill response plans are developed at three levels: national, area, and regional. The USCG also funds an Oil Spill Response Research & Development Program.

**Australia.** To develop Australia's 2011 national oil spill response plan, a national risk management model was used to assess the level of risk for 120 regions. For each region, data on the environmental sensitivity and ship traffic were gathered. Global oil spill data were used to understand the characteristics of past oil spills. These data were used to predict the probability of a spill for each region. Both the national and regional plans used these data for the response plans.

**Norway.** Norway uses risk analysis models to develop the most probable oil spill scenarios for each region and simulation tools to analyze the response to each scenario. The modeling criteria are for an oil spill of between 110,000 and 150,000 barrels (specifically 15,000 and 20,000 mt) and, unlike in the United States, no "worst case" scenarios are used. The simulations provide an estimate on the amount of oil recovered, dispersed, stranded, and evaporated. The response times necessary to achieve the cleanup goals are also evaluated. These results inform the oil spill response plans.

1. Source: Transport Canada, "Environmental Oil Spill Risk Assessment Project—Newfoundland," http://www.tc.gc.ca/eng/marinesafety/oep-ers-regime-study-1470.htm, accessed 21 May 2013.
2. Source: 2010 Fall Report of the Commissioner of the Environment and Sustainable Development, Chapter 1, Section 1.27, http://www.oag-bvg.gc.ca/internet/English/parl_cesd_201012_01_e_34424.html#hd4a, accessed 23 May 2013.
3. In early 2013 Canada issued a request for proposal to perform a risk assessment for marine spill in Canadian waters. Source: Transport Canada (2013), "Harper government announces pan-Canadian risk assessment study on marine safety," February 4, 2013 Press Release - http://www.tc.gc.ca/eng/mediaroom/releases-2013-h006e-7044.htm, accessed 2 April 2013.

1. In Canada, historically the risk assessment tools have been used in some regional response plans.

## Oil spill response equipment and requirements

What is the most prudent level of equipment for responding to spills? Each jurisdiction answers this question differently. In most jurisdictions compared here, the amount and type of equipment and its location are determined by risk analysis and scenario planning. This results in unique thresholds for each region that can change according to the season, the volume of shipping, and even the environmental sensitivity of different regions (e.g., the Great Barrier Reef). Other jurisdictions—such as Canada—rely on more rigid standards (see the box "Oil spill response equipment and requirements").

### Oil spill response equipment and requirements

**Canada.** On both the East and West coasts, Canada requires oil spill equipment capable of responding to a spill of 75,000 barrels (10,000 mt) within 72 hours and cleaning up to 500 meters of shoreline per day.[1] Transport Canada may also require additional dedicated oil handling equipment for individual oil handling facilities. These requirements are based on each facility's unique needs. In general, the Canadian response requirement is uniform on both coasts and is not based on regional risk assessments. In the event of a larger spill, the resources of a specific area could be supplemented with those from other regions or other countries. The CCG also has its own stockpiles of equipment that can be brought in to assist.

For the Northern Gateway project, which includes the potential for VLCC (some of the largest tankers in the world), the Joint Review Panel for Northern Gateway has requested, as a potential condition of approval, capacity to respond to a spill of about 220,000 barrels (30,000 mt) within 6 to 12 hours plus travel time.**

**United States.** The United States has many private oil spill removal organizations (the US Gulf Coast alone has over 100). Owing to the relatively high volume of crude oil movements in the US Gulf Coast region, there is a large amount equipment located around the coastline, and the US Navy has equipment at bases that can be deployed in case of an emergency.*** Government oil spill response resources are intended to provide backup for the private sector. Regional requirements for equipment vary and are based on regional plans and specific risks for each location. Therefore specific examples of requirements are difficult to obtain.

**Australia.** Australia has nine regional centers for storing spill response equipment. Ports, states, and oil companies hold additional equipment stocks. A central database, called the Marine Oil Spill Equipment System, monitors the location of all equipment and is maintained by a federal agency. Since regional requirements vary, specific response equipment requirements are difficult to obtain.

**Norway.** In addition to equipment maintained by the Norwegian Coastal Administration and municipal governments, private oil spill response organizations and oil companies have cleanup equipment for responding to offshore oil well spills. Since regional requirements vary and are determined by a risk-based assessment process, the specific levels of response equipment are difficult to obtain.

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*Required response capability varies depending on the size of the spill, from the capacity to respond to spills of 1,100 barrels (150 mt) within 6 hours to the maximum capacity of 75,000 barrels (10,000 mt) within 72 hours. Source: Transport Canada, http://www.tc.gc.ca/eng/marinesafety/tp-tp14539-review-current-regime-2279.htm, accessed 17 May 2013.

**National Energy Board, Potential Panel Conditions, Attachment B—Collection of potential conditions, Page 5, April 12, 2013, https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=942629&objAction=browse&redirect=3.

***The US Gulf Coast had over 38,000 tanker port callings in 2012—over three-quarters of all US movements—and 30% of these were large tankers. Source: IHS Maritime.

*Oil sands bitumen blends—A special case?*

In comparing Canada's oil spill response requirements to those of other jurisdictions, concerns have been raised that, if spilled in the ocean, oil sands bitumen blends could behave differently—potentially sinking more quickly than other heavy crudes. If this were the case, different response requirements (regarding speed, capability, and accessibility) could be needed. Although there is limited experience with cleanup of oil sands heavy crudes in the marine environment, so far there is insufficient evidence to conclude that oil sands bitumen blends would perform differently than comparable heavy oils. However, this is an area of active research (see the box "Spill performance of bitumen blends").

**Spill performance of bitumen blends**

**Does oil sands bitumen blend float on water?**

Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with lighter hydrocarbons—typically natural gas condensate—into a bitumen blend. The bitumen blend mixture is of a low enough viscosity to flow in a pipeline. If projects to export oil from Canada's West Coast are completed, greater quantities of bitumen blend will be transported from Alberta to the coast by pipeline and eventually loaded onto tankers.

Like other heavy crude oils, bitumen blends are lighter than fresh or salt water; and since they are less dense, they float upon initial release into a marine or freshwater environment.[1]

**In the event of oil spill into the ocean, will bitumen blends remain afloat?**

On initial release into a marine environment, crude oils float. But, over time, the environment can alter the density of the spilled crude through a process called weathering. Weathering takes time, and the effect varies with the type of crude—light or heavy. Lighter oil is more susceptible to evaporation. Some refined products, such as gasoline or diesel, are sufficiently light that most will evaporate quickly, negating the need for an extensive cleanup. The heavier a crude oil, the more it will persist in the marine environment (since less of it will evaporate). It is for these persistent oils that spill prevention and response regimes have been established.

Experience with some heavier persistent oils, such as maritime fuel known as bunker, has shown that wind, turbulence, and dispersants can break up the oil into droplets. These droplets can take on sediment, and the combined density of some of the spilled oil can become neutrally buoyant and submerge. Once submerged, oil may float in the water column, sink toward the bottom, or later reemerge on the surface. Sunken oil can be hard to locate and subsequently to recover. The longer oil is left to weather, the more likely it will become neutrally buoyant; this is true of most persistent oils. Sinking is more likely to occur in shallow water with higher levels of sediment and with high wave activity that encourages the mixing of oil, sediment, and water, which increases the density of the resulting mixture; other key variables that affect weathering are the salinity and temperature of the water, as they impact the density of the water and the oil.[2]

1. According to the Geological Survey of Alberta, the density of bitumen from the Canadian oil sands ranges from 1,014 to 986 kg ,per cubic meter (8–12°API). However, bitumen blend density is lower; according to CrudeMonitor.ca, the specific gravity of diluted bitumen ranges from 934 to 923 kg per cubic meter (19–22°API). Freshwater has a specific gravity of 1,000 kg per cubic meter (10°API), whereas salt water density ranges (depending on salinity) from about 1,030 to 1,020 kg per cubic meter (6–7°API).
2. Source: Castle, R. W., Wehrenberg, F., Barlett, J., and Nuckols, J. (1995), "Heavy Oil Spills: Out of Sight, Out of Mind," International Oil Spill Conference Proceedings, February 1995, Vol. 1995, No. 1 (February 1995) pp. 565–571, https://dx.doi.org/10.7901/2169-3358-1995-1-565, accessed 8 April 2013.

## Spill performance of bitumen blends (continued)

There are different opinions on how bitumen blends would perform in a marine environment. In the event of a bitumen blend spill, the diluents, which can constitute up to 30% of the blend, could evaporate, leaving denser (less buoyant) bitumen behind, which would be more at risk of sinking. Recent studies by SL Ross (conducted as part of the Northern Gateway pipeline review) simulated an oil spill in a laboratory environment and found that the density of a bitumen blend (specifically Cold Lake Blend—a dilbit) in a marine environment does change over time. In its analysis, the density of the blend increased after 12 days, approaching that of freshwater, but did not sink since ocean water is heavier than fresh water.[3]

In 2007 another type of bitumen blend was accidently released from the land into ocean water in Vancouver Harbor. This provided practical experience of a land-based spill with a unique blend of synthetic heavy crude oil (not to be confused with SCO defined earlier) and bitumen (specifically Albian Synthetic Heavy).[4] The spill occurred under ideal conditions of warm and calm water. Responders noted that the oil sands blend performed similar to other heavier oils, such as bunker. Their equipment worked well, and no traces of sunken oil were found.[5]

In 2010 another land-based spill, involving bitumen blends, made its way into the freshwater of the Kalamazoo River in Michigan, and some (estimated at 15–20%) of the crude oil was reported to have sunk into the water column.[6,7] In this instance, conditions were notably less than ideal and somewhat different from an ocean environment.[8]

Simple chemistry suggests that bitumen blends would float upon release into a marine environment because initially it is less dense than water. However, marine environments are dynamic, and a number of factors beyond the oil itself—such the weather, sediment level, temperature, and the salinity of the water itself—can influence what happens in a spill. Under the right conditions heavier oils, such as bunkers, can become neutrally buoyant and submerge. However, there is insufficient evidence to conclude that bitumen blends are more or less prone to sinking than heavy oil of comparable density. To date, practical experiences have been limited, tests have been lab scale, and methodologies have been debated. More research is warranted. The Government of Canada has committed to more research in this area and as a potential condition for the Northern Gateway Project (in addition to scenario modeling for submerged oil).[9] If bitumen blends were found to be more susceptible to weathering and to the risk of submerging, greater and faster response capabilities could be warranted to respond to a spill before the effects of weathering can occur.

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3. February 6, 2012, Submission to Northern Gateway Joint Panel Review by Northern Gateway Pipelines Limited Partnership. SL Ross, (2012), "J Meso-scale Weathering of Cold Lake Bitumen/Condensate Blend," October 2012, http://www.ceaa-acee.gc.ca/050/documents/p21799/85785E.pdf.
4. Albian Synthetic Heavy is a blend of partially upgraded heavy oil (synthetic heavy) and bitumen with a density of 939 kg per cubic meter (five-year average, source: CrudeMonitor.ca). The precise blend is proprietary.
5. Western Canadian Marine Response Corporation.
6. Enbridge estimates that 20,082 barrels of crude oil were released from Enbridge's Line 6B, 22.5% was Western Canadian Select (a proprietary oil sands blend of heavy crude—both bitumen and conventional heavy—SCO, and diluents); and 77.5% Cold Lake Blend—a dilbit. Source: Enbridge Pipelines LP. (2011), "Line 6B Incident, Marshall, Michigan Conceptual Site Model," May 10, 2011, Approved July 8, 2011.
7. Enbridge estimated that 15–20% of the oil that reached the Talmadge Creek and Kalamazoo River submerged. Source: Northern Gateway Pipelines Limited Partnership (2012) "Northern Gateway Response to JRP Information Request No. 10 (A42038)" https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/384192/620327/624798/823127/B74-2_-_NGP_Response_to_JRP_IR_No._10_-_A2T9E4?nodeid=823025&vernum=0, accessed 23 May 2013.
8. Crude oil that was released from the ruptured Line 6B was forced from the underground pipe and through the earth, emerged on the surface, and flowed overland before entering the freshwater of the Talmadge Creek and then down into the Kalamazoo River. Over time the density of the crude oil is reported to have fallen owing to evaporation, interaction with sediment, and the unique dynamic nature of the river. High river flows from recent rainfall and several constrictions and obstructions (dams/dikes) contributed to turbulent flow, are believed to have encouraged mixing, and may have contributed to driving spilled oil down into the water column. Source: Enbridge Pipelines LP. (2011), "Line 6B Incident, Marshall, Michigan Conceptual Site Model," May 10, 2011, Approved July 8, 2011.
9. Source for the Government of Canada research, March 18, 2013 Transport Canada press release, "Harper government announces first steps towards World-Class Tanker Safety System," http://www.tc.gc.ca/eng/mediaroom/releases-2013-h031e-7089.htm, accessed 23 May 2013. Source of Enbridge Northern Gateway potential condition, National Energy Board, Potential Panel Conditions, Attachment B—Collection of potential conditions, Pages 38–39 , April 12, 2013, https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=942629&objAction=browse&redirect=3. – accessed 11 June 2013.

## Funding

In all the jurisdictions we studied, the polluter is responsible for oil spill cleanup costs. But there are other costs. Who pays for regulating the industry, inspection, enforcement, and the activities taken to prepare for an oil spill? For all jurisdictions, both government and private funding play a role. The most sustainable funding model is one that adjusts with changes in shipping activity. Compared with Australia and Norway, the Canadian and US systems have weaker linkages between activity and funding (see the box "Funding").

### Funding

**Canada.** In Canada, funding for prevention and response activities is from a mixture of private and public sources. While industry funding varies with shipping activity, federal funding is not directly linked to shipping activity.

Industry covers most spill response costs (through mandated third-party response organizations that charge shipping levies: ships are charged both flat fees and fees that vary with the cargo size) as well as costs for pilotage and for the regulatory review of new projects.

The federal government funds supports policy, regulation, and enforcement agencies, such as Transport Canada and the CCG, which deliver many prevention, response, and enforcement activities (including navigational aids, port control, inspections, weather forecasts, air and ship patrols, response planning, and exercises). Therefore, Canada's prevention and response activities can be sensitive to federal budgets.

**United States.** Like in Canada, the US oil spill response is funded by a mix of public and private sources. The vast majority of the cost for US government agencies (such as the USCG and the US EPA) comes from the public and (as in Canada) this is can be influenced by federal budgets.* As in Canada, industry pays for private oil spill response organizations.

**Australia.** The shipping industry pays for most of the cost for regulation and spill response in Australia. Ships pay levies for aids to navigation, safety regulations, air surveillance, and port control. Levies also cover the cost of the National Plan and the provisions for response, including emergency response vessels, oil spill response, aircraft, and other expenses.

**Norway.** The Norwegian government covers most costs for preparing for ship-source and terminal oil spills. The extensive range of equipment held by national and local government and the oil industry (which is responsible for offshore oil spill response) has reduced the number of private cleanup contractors in Norway. Onshore response is supported in part by a fee companies pay to municipalities which allows them to include these capabilities in their response plans. Compared with other jurisdictions explored here, in Norway the public is exposed to more of the funding for prevention and response capability. However, unlike other nations explored in this analysis, Norway has a unique relationship with industry. The Norwegian government participates directly in the petroleum sector as an investor and is the majority owner of the country's largest oil company.[2,3] As in other jurisdictions, in the event of a spill, the polluter is required to cover cleanup costs.

1. A small portion—we estimate less than 2%—comes from other means. US government agencies can receive allocations that are linked to shipping activity. For instance, agencies receive funding from the Oil Spill Liability Trust Fund that was established through a tax per barrel of oil transported by tanker. Appropriations for agencies from this fund are typically less than US$100 million (see Figure 11 in the following source); meanwhile the USCG total budget in 2012 was over US$10 billion. Source for appropriations funding: http://www.uscg.mil/ccs/npfc/docs/PDFs/Reports/Liability_Limits_Report_2012.pdf, accessed 22 May 2013. Source for USGC 2012 budget: http://www.uscg.mil/top/about/doc/uscg_snapshot.pdf.
2. Source: Norwegian Ministry of Petroleum and Energy, http://www.regjeringen.no/en/dep/oed/Subject/state-participation-in-the-petroleum-sec/the-states-direct-financial-interest-sdf.html?id=445748, accessed 22 May 2013.
3. Source: Statoil, http://www.statoil.com/annualreport2011/en/shareholderinformation/pages/majorshareholders.aspx, accessed 22 May 2013.

## PART 3: SPILL LIABILITY AND COMPENSATION

Concern about a proposed increase in the number of large tankers off Canada's West Coast is raising questions about the adequacy of spill compensation in Canada. Part 3 explores Canada's ship-source spill liability and compensation regime—how it functions, how much money is available, its sufficiency, and how Canada compares with other jurisdictions.

### CANADA FOLLOWS THE INTERNATIONAL REGIME: STRICT BUT LIMITED LIABILITY

Canada and 130 other nations have agreed to strict but limited liability for shipowners in oil spill compensation.[1] Strict liability provides few defenses for shipowners in the event of a spill: if a spill occurs and it came from a particular ship, the owner of that ship is liable. There are very few exceptions to this rule.[2] Because shipowners are by default automatically liable in the event of a spill, financial limitations (caps on the maximum amount the shipowner could owe in the event of a spill) have been imposed. Liability limits can be voided only if there is willful negligence on behalf of the shipowner. These liability limits were a compromise among shipowners, marine insurers, and coastal nations.

### INTERNATIONAL FUNDS PROVIDE ADDITIONAL SPILL COMPENSATION

If the cost of a spill exceeds the liability limit for a vessel (a ship's liability limit increases with the ship size to a maximum of C$140 million), international compensation funds provide additional coverage to member states (and persons within them) for pollution damage.[3] The international compensation regime, including shipowner's liability and the international compensation funds, are paid out supplementally until full compensation is achieved or the funds are exhausted.

Since the initial pollution compensation fund was established in 1971, costs associated with oil pollution response and cleanup have increased, and the nature of loss admissible for compensation has broadened to include remediation and economic losses that flow directly from environmental damage. Compensation funds have also grown, and today two layers of international funding have been established: the International Oil Pollution Compensation Fund, 1992 (known as the 1992 Fund); and the International Oil Pollution Compensation Supplementary Fund, 2003 (known as the Supplementary Fund).[4] Combined these funds are

1. Source of number of nations that have ratified: IMO, Status of Conventions, www.imo.org/about/conventions/statusofconventions/pages/default.aspx, accessed 18 April 2013. Key components of the international regime (as supported by the ratification of most nations) include the Civil Liabilities Convention (CLC); the International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage; and the International Convention on Civil Liability for Bunker Oil Pollution Damage.
2. Exceptions are acts of war or grave natural disasters, sabotage, or negligence of public authorities.
3. Ship liability limitations are established internationally and are valued in International Monetary Fund (IMF) Special Drawing Rights (SDRs), which are supplementary foreign exchange reserve assets. SDRs represent a claim to currency held by IMF member countries for which they may be exchanged. Note: 1 SDR = C$1.528 on 12 April 2013.
4. The Supplementary Fund Protocol was adopted in 2003 and entered into force in 2005.

capable of providing up to C$1.18 billion in compensation per incident and would contribute to cover costs if a spill occurred in Canadian waters.[1]

Canada is a party to both international funds and has also established its own additional layer of compensation domestically. Canada's Ship-Sourced Oil Pollution Fund (SOPF) can provide up to C$159 million of additional compensation. The SOPF is funded by a tariff charged on the loading or unloading of crude oil from tankers in Canada.[2] Like other funds, the SOPF has a prescribed limit. It can also be used to address other types of marine pollution, such as so-called mystery spills (spills of unknown origin). In the absence of any major spills in recent history within Canadian waters, it has been fully funded since 1976. Table 2 shows the total value of oil spill compensation funds in Canada.

## ADEQUACY OF COMPENSATION

Based on historical evidence, the international funding levels have been sufficient to cover most oil spills from ships. Since the International Oil Pollution Compensation (IOPC) Funds were established in 1978, it has been involved in 145 incidents and cumulatively paid out about C$900 million for compensation.[3] In 2004, a study by the IOPC Funds looked at the question of adequacy of compensation. It found that from 1978 to 2002 in over 5,800 spills worldwide (not including the United States which does not participate in the international regime) 98% of incidents were fully compensated by the first layer of coverage—ship-owner liability (about C$140 million).[4] According to the IOPC there are no incidents that it has been involved in that exceeded (or are expected to exceed) the level of compensation currently available in Canada (in excess of C$1.3 billion).[5] Since the Supplementary Fund was established in 2003, it has yet to be used.[6]

However, if a very large spill were to occur, under the right conditions, the level of compensation could be insufficient. To date, the most expensive tanker oil spill remains the *Exxon Valdez* incident, for which cleanup expenses alone exceeded US$2 billion (taking into

1. These funds are administered by the International Oil Pollution Compensation Fund (IOPC) and are financed by contributions from member countries based on their crude oil import/export levels. Accessing these funds is not automatic, and claimants are required to prove their economic loss. Compensation is available to all parties, including shipowners, and there is no priority for compensation. All successful claims are paid out proportionally—including if claims exceed available funds. These funds cover quantifiable economic losses. Indirect environmental damages arising from the long-term impacts (nonrestorable) on wildlife habitat, such as on fish stocks, local birds, and other wildlife populations, are not covered.
2. The SOPF was established in 1989 and took over from its precursor organization, the Maritime Pollution Claims Fund, which had existed since 1973.
3. Based on £567 as reported in the IOPC (2012), "2012 Annual Report," Page 16, http://www.iopcfunds.org/uploads/tx_iopcpublications/AR2012_e.pdf - accessed June 13, 2013
4. Source: IOPC, "Review of the International Compensation Regime," Third Intersessional Working Group, Agenda Item 2, May 14, 2004. http://documentservices.iopcfunds.org/meeting-documents/download/docs/2424/lang/en/ - accessed 13 June 2013.
5. Source: IOPC. Discussions with the IOPC. Note: Since 1978 there have been four incidents the IOPC has been involved in that exceeded the 1992 Fund levels (C$318 million): the *Nakhodka* (1997), *Erika* (1999), *Prestige* (2002), and *Hebei Spirit* (2007). The *Hebei Spirit* is the only major incident to have occurred in recent years. Although this case is still ongoing, recent claims judgments in South Korea place the level of compensation required in excess of the 1992 Fund, but under what would have been available through the Supplementary Fund (had South Korea joined the supplementary fund at the time of the incident). Source: IOPC, *Hebei Spirit,* Recent Developments [update], January 2013, http://www.iopcfunds.org/incidents/incident-map/#2007-185-December – accessed 11 June, 2013 .
6. Source: IOPC, www.iopcfunds.org/about-us.

account other factors, such as economic loss and environmental damage, the costs are much higher).[1] Since this happened almost a quarter-century ago, it would be expected that the cost for a similar spill in a similar environment could be higher today. Some studies have suggested that costs arising from a spill on the West Coast could exceed what is currently available in Canada.[2]

### How does Canadian coverage compare?

The level of compensation available in Canada exceeds what is available internationally. Although most nations have adopted the international regime, only a smaller subset (including Canada) participates in all levels of international funding. Of the two tiers of international funding (listed in Table 2, above), Canada is one of only 29 nations to have joined both funds and to have access to the full C$1.18 billion. Most nations (110) have only joined the first tier of funding, which provides up to C$318 million.[3] In the event the IOPC funds are inadequate, Canada's SOPF provides an additional layer of compensation ($159 million), making the total available funding available in Canada (from domestic and international regimes) $1.3 billion per incident.

The United States is often cited to contrast with the international regime, as it has chosen to opt out of the international liability and compensation regime and establish its own rules. The US system has many similarities to the international regime—strict but limited liability and a compensation fund for remediation and uncompensated damages. Shipowner liability extends to $1 billion, and a domestic compensation fund is available to provide up to $1 billion each for remediation and uncompensated damages. In total this amounts to $2 billion ($1 billion in uncompensated funding is provided as coverage should the polluter be unknown or unable or unavailable to pay.) The US federal regime also does not preempt state law, and some states, including Alaska and Washington, have established unlimited liability. Although unlimited liability may seem attractive to some stakeholders, shipowners, could choose to manage risk under such a regime by incorporating each vessel separately. In the instance of a large liability (which exceeds their insurance), shipowners could opt for abandonment as a mitigation strategy, an option that helps no one.

In contrast to most other jurisdictions, in the United States damage to the environment that cannot be directly restored (such as long-term impact to the ecosystem and wildlife) is also covered. The ultimate value of this greater liability is a matter of debate. Although one might conclude that broader coverage is better coverage, these costs are harder to substantiate and can be significant, which can reduce the funding available for other damages. For

1. Note: Total settlement still ongoing. Source: Exxon Valdez Oil Spill Trust Council, http://www.evostc.state.ak.us/facts/qanda.cfm, - accessed 22 May 22, 2013.
2. Hotte, N. and Sumaila, U. R. (2012), "Potential economic impact of a tanker spill on ocean-based industries in British Columbia." Fisheries Centre Research Reports, 2012 V. 20, No. 7.
3. IMO, Status of Conventions, www.imo.org/about/conventions/statusofconventions/pages/default.aspx, accessed 12 April 2013.

**Table 2**

**Oil tanker pollution compensations funds and limits available in Canada**

| Compensation funds and liability limits (international liability and compensation funds apply cumulatively) | Value (Canadian dollars)[1] |
|---|---|
| **Civil Liability Convention & Shipowner Liability (est. 1992)** In the event of an incident that results in ship-source pollution, the liability of the shipowner is capped under the International Convention of Civil Liabilities, which Canada adopted in the Marine Liability Act. Shipowners are obligated to maintain insurance to this level of coverage. | $140 million |
| **International Oil Pollution Compensation Fund (est. 1992)** This fund pays compensation for oil pollution damage should full compensation not be reached under CLC. These funds are paid out as top-up to the shipowner's liability, or for the full amount should the shipowner not be liable. | $318 million |
| **International Oil Pollution Compensation Supplementary Fund (est. 2005)** This top-up fund is used if there is a valid claim and the prior levels of funding are inadequate to address the level of compensation required. | $1.18 billion |
| *Total compensation available from ship owners and international funds* | *$1.18 billion*[1] |
| **Ship-Sourced Oil Pollution Fund (est. 1989)** This fund, which is unique to Canada, is available to provide funds, in addition to the international liability regime, up to $159 million. It can be applied to mystery spills, and all classes of ships (not solely oil tankers). | $159 million |
| *Total compensation available in Canada (inclusive of international funds)* | *$1.34 billion* |

Source: IHS CERA, Wave Point Consulting Ltd.

1. The international compensation regime, including shipowner's liability and the international compensation funds, are paid out supplementally up to C$1.18 billion. In the event shipowners are unavailable to pay, the international regime will cover this share of the compensation regime.

Note: Estimated value in Canadian dollars based on IMF Special Drawing Rights (SDRs) which are supplementary foreign exchange reserve assets. SDRs represent a claim to currency held by IMF member countries for which they may be exchanged. Note 1 SDR = C$1.54 on 13 February 2013.

example, about a quarter of the damages that Exxon paid as a result of the *Valdez* spill were environmental.[1]

There are no international provisions to prevent Canada from implementing additional compensation measures (such as the SSOF Canada already has in place). The Government of Canada has announced plans to review these issues. A panel of experts was appointed on 18 March 2013 to review the current state of maritime tanker safety in Canada, and the Department of Transport has also announced its intention to modernize the SOPF, which will include a review of the current liability and compensation regime for ship-source oil pollution.[2] The results of both reviews are expected this fall.

1. Total costs have been estimated at over $4 billion: cleanup (over US$2 billion); fines and penalties (which included environmental damages, over $1.1 billion); and private claims of economic loss (just under US$1 billion). Some litigation is still ongoing, and this estimate does not include costs for legal fees, interest, and salvage. Source: Multiple Sources: Exxon Valdez Oil Spill Trust Council for clean-up cost and fines and penalty costs, http://www.evostc.state.ak.us/facts/qanda.cfm and Exxon Qualified Settlement Fund for civil litigation costs, http://www.exspill.com/News/LitigationHistory/tabid/1918/Default.aspx, both accessed 7 June 2013.
2. Sources: Transport Canada (2013), Press Release, http://www.tc.gc.ca/eng/mediaroom/releases-2013-h031e-7089.htm, accessed 23 May 2013. Transport Canada (2013), Press Release, http://www.tc.gc.ca/eng/mediaroom/backgrounders-tanker-safety-system-liability-compensation-7091.htm, accessed 4 June 2013.

## CONCLUSION

For most coastal nations, the transport of crude oil by sea is a common and often large-scale practice. Currently oil tanker activity on the West Coast of Canada is modest by comparison. Pipeline projects have been proposed to export greater volumes of crude from the Canadian West Coast, raising questions about Canada's ability to ship crude safely.

Although the *Exxon Valdez* incident is still a relevant example of the extent of damages that can result from an oil spill, new technology and practices implemented since 1989 have greatly reduced the potential for this type of event. Spill frequency and volumes have declined over the past few decades as a result.

The rules in Canada tend to be similar to those of other nations, since the international nature of maritime shipping has led to regulatory consistency across jurisdictions. How nations apply these rules, however, in terms of prevention and response measures such as pilotage, spill response plans and capabilities, and aids to navigation, can differ, reflecting the resources and needs (economic, social, and environmental) of each country. In this context, in comparing regions, it becomes clear that what is best for one or even several nations may not be best for all, and comparisons should be made carefully.

The prospect of increased tanker traffic on Canada's West Coast has led to new questions that have prompted the Government of Canada, in March 2013, to appoint an expert panel to review the country's current tanker safety system and to propose improvements.[1] The regulatory review process is currently under way for the Northern Gateway Project and expected later for the Trans Mountain Pipeline Expansion. Both reviews are likely to result in recommendations for improvements. This year Canada started a national risk assessment study and has announced, among other improvements, the implementation of an incident command system for the CCG.

Improvements in Canada's level of prevention and response capabilities on the West Coast in response to increased tanker movements would enhance the safety of the shipping industry as a whole. For example, more large tugs and greater spill response capabilities that would accompany the Northern Gateway Project would improve safety not only for those operations, but also all other shipping activity in the region.

Consequently, if Canadian West Coast tanker movements increase, it is likely that some measures taken to prepare for an oil spill would be adjusted from current practice to reflect the growing need. Ultimately this could lead to improved safety for all shipping in the region.

1. Transport Canada (2013), Press Release, http://www.tc.gc.ca/eng/mediaroom/releases-2013-h031e-7089.htm, accessed 23 May2013.

## REPORT PARTICIPANTS AND REVIEWERS

On 21 March 2013, IHS CERA hosted a focus group meeting in Vancouver, British Columbia, to provide a venue for oil sands stakeholders to discuss perspectives on the key issues related to transport of Canadian oil sands (and other crude oils) by tanker. 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.

American Petroleum Institute (API)

Alberta Innovates, Energy and Environmental Solutions

British Columbia Chamber of Shipping

British Columbia Ministry of Environment

British Columbia Pilots Association

BP Canada

Canadian Association of Petroleum Producers

Canadian Oil Sands Limited

Cenovus Energy Inc.

Conoco Phillips Company

Canadian Natural Resources Ltd.

Government of Alberta, Department of Energy

Enbridge Northern Gateway Pipelines LP

IBM Canada

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

Kinder Morgan Canada

Puget Sound Harbor Safety Committee

Statoil Canada Ltd.

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

United States Coast Guard

Washington State Department of Ecology

Western Canada Marine Response Corporation

# IHS TEAM

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**KRISPEN ATKINSON,** Maritime Business Analyst, leads the Ports & Terminals team for IHS Maritime, which actively monitors over 3,700 ports worldwide. Mr. Atkinson joined Fairplay (which was subsequently acquired by IHS in 2005, bringing extensive knowledge of the shipping industry through personal interest pursuits and the development of his own database of ships. On joining Fairplay he applied his knowledge of ships and cargoes to the commercial arena and quickly joined the management ranks. Over the past eight years, Mr. Atkinson has worked across several data disciplines within IHS Maritime, including leading the New Construction, Characteristics, and Ships in Service departments. He is a widely respected speaker and has presented at industry bodies such as Community of European Shipyards Associations and China State Shipbuilding Corporation.

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# ANNEX A: INTERNATIONAL MARITIME SHIPPING GOVERNANCE

At one time, a nation's territorial waters—those waters where all domestic laws apply—were determined by the distance of a cannon shot from shore: about 3 nautical miles.[1] As technology advanced, nations extended their reach into the offshore. To address the potential for conflicting interests between nations, a common set of rules was needed.

The United Nations has been central in establishing these common rules, the most important mechanisms being the United National Convention on the Law of the Sea (UNCLOS) and the International Maritime Organization (IMO). It is important to understand that the regulations that govern international shipping are fluid and are evolving continually as members to these conventions raise issues and concerns and seek to amend the existing rules.

## THE UNITED NATIONS CONVENTION ON THE LAW OF THE SEA

To date, 165 nations have ratified UNCLOS, including Canada (but not the United States). UNCLOS establishes jurisdictional boundaries between international waters and waters controlled by nations. Within a nation's internal waters (which generally includes all rivers, fjords, inlets, canals, and harbors), the federal government is free to impose whatever requirements it sees fit, including limiting access to certain types of vessels.[2] Today, coastal nations' ability to regulate is principally limited to the first 12 nautical miles offshore, known as territorial waters. Within these waters other nations have the right to "innocent passage," which is regarded as the peaceful and meaningful movement through these waters. Past this point a coastal nation's sovereignty diminishes and a key international principle of the freedom of navigation takes on increasing importance. However, coastal nations have the exclusive right to all natural resources and to protect the environment up to 200 nautical miles offshore.

## THE UNITED NATIONS INTERNATIONAL MARITIME ORGANIZATION

The IMO was established to help address the jurisdictional challenges of regulating international shipping and is the primary international body for establishing rules and guidelines for the shipping industry. Its purpose is to improve the safety and security of shipping and the prevention of marine pollution by ships. This includes helping to ensure consistency between the rules established within various distinct coastal states as well as with the countries in which vessels are registered.

It is through the IMO that a number of international conventions and agreements have been implemented, such as the Civil Liability Conventions and International Oil Pollution Compensation Fund, which established the international liability and compensation regime discussed in Part 3; the Safety of Life at Sea Conventions (SOLAS), which put in place minimum standards for construction and operation of ships; or the International Convention

1. A nautical mile is approximately 1.15 miles, or 1.85 kilometers.
2. This could include limitations on vessel size, design, equipment, and/or onboard communications and navigation aids. For example, in the United States special requirements were placed on tankers transporting US crude oil between US ports. The Jones Act requires such tankers to be owned, operated, and crewed by US citizens.

for the Prevention of Pollution from Ships (MARPOL), which aims to minimize ship-source pollution and phase out international single-hull tankers.

## ANNEX B: KEY POLICY TOOLS FOR SAFETY OF MARITIME SHIPPING

Maritime shipping, including oil tankers, can pose a risk to marine ecosystems. To mitigate these risks, a suite of domestic and international policies has been adopted, aimed at prevention, response, and mitigation. Table B-1 is a list of key policies, both domestic and international; their purpose; and how they influence maritime shipping (particularly tanker activity) in Canada.

**Table B-1**

**Summary of key maritime shipping policy tools**

| Instrument | Domestic or international policy | Purpose of measure | Description |
|---|---|---|---|
| Double hull tankers[1] | International | Prevention | Requires all tankers above 5,000 mt to be double hulled by 2015. |
| Special Areas (SAs)[1] | International but onus is on domestic policy to identify areas | Prevention | SAs impose rules to prevent/limit ship-source pollution (such as sewage, air pollutants, etc.) outside a state's territorial waters in environmentally sensitive areas. For example Canada created an area in the Bay of Fundy to protect whales from shipping. |
| Particularly Sensitive Sea Areas (PSSAs)[1] | International, but onus is on domestic policy to identify areas | Prevention | PSSAs impose special rules, including routing measures, in areas beyond a state's territorial waters to protect ecologically or scientifically sensitive areas vulnerable to damage by marine shipping. For example, Australia created an area to protect the Great Barrier Reef from the risks posed by marine shipping. |
| International Safety Management (ISM) Code | International | Prevention | Provides an international standard for safe management of ships for pollution prevention. This requires that each ship have a safety management system that includes, among other things, procedures for reporting accidents and responding to emergencies. |
| International Ship & Port Facility Security Code | International | Prevention | Requires that a minimum level of security be established for ships and port facilities. For instance ships and ports must have security plans, security officers, and equipment as well as monitoring and restrictions on ship/port accessibility. |
| International Convention on Standards of Training, Certification and Watchkeeping for Seafarers | International | Prevention | Establishes minimum standards for masters, officers, and watch personnel on merchant vessels. |
| Places of refuge | International, but onus on domestic policy to identify areas | Prevention / mitigation | Identifies a prescribed location where ships can go if they need assistance. Examples include the accidental pollutants or the need for medical assistance (e.g., communicable disease outbreak). |
| Port state of control | International | Prevention | Inspection of ships ensures compliance with international, flagged-state, and domestic rules. |

**Table B-1**

**Summary of key maritime shipping policy tools (continued)**

| Instrument | Domestic or international policy | Purpose of measure | Description |
|---|---|---|---|
| International Convention on Oil Pollution Preparedness, Response, and Co-operation | International | Response/ mitigation | Requires ships to report pollution and participating nations to be prepared in the event of a spill (e.g., have detailed response plans, run response exercises, and stockpile response equipment) and to render assistance to one another. |
| Civil Liabilities Convention (CLC) and the International Oil Pollution Compensation Fund (IOPC Fund) | International | Mitigation | Imposes strict liability on the ship owner for marine pollution and establishes an international compensation fund to provide assurance that funds are available for cleanup and damages. |
| Ship-Source Oil Pollution Fund (SSOF) | Domestic | Mitigation | Establishes an additional layer of compensation funding in Canada that provides assurance that in the event of a spill, fund are available to address cleanup and damages.  This fund can also cover costs to address the risk of oil pollution from ships, such as salvages, etc. |
| Aids to navigation | Domestic | Prevention | Canada provides navigational aids such as lights, buoys, markers, fog signals, radar, and radio, as well as weather forecasts.  Canada also requires all ships within its waters to use appropriate Canadian maps, and merchant vessels must signal their location at all times. |
| Compulsory marine pilotage | Domestic | Prevention | Mandatory pilotage is required in certain coastal water areas of Canada using specially trained pilots with local knowledge of the area aid in the navigation of ships in coastal waters. |
| Marine Protected Areas | Domestic but principal routes also in international law | Prevention | Provides additional protection for areas of high biodiversity that can extent from all or a portion of the sea surface through to the seabed.  Can impose special navigational or pollution rules around sensitive environmental areas (either more cautious rules or routing measures) |
| Oil spill response | Domestic | Response/ mitigation | Canada Shipping Act establishes regulations to protect all navigable waters and imposes regulations on vessels, tankers, and oil handling facilities.  It also requires all merchant vessels to employ the services of a dedicated, professional spill response organization within Canada. |

**Table B-1**

**Summary of key maritime shipping policy tools (continued)**

| Instrument | Domestic or international policy | Purpose of measure | Description |
|---|---|---|---|
| Port authorities and terminal procedures | Domestic | Prevention/ Response | Port authorities can establish procedures for safe loading and unloading, which can also provide for more rapid response in the case of emergency. |
| Project specific risk assessments (e.g., environmental assessments, joint review process, etc.) | Domestic | Prevention/ Response/ Mitigation | Project-specific reviews associated with port expansions or new terminals can identify, mitigate, or avoid risks associated with a specific project. This can include terminal operations, vessel navigation, potential pollution, and sensitive ocean areas. |
| Tug assistance | Domestic | Prevention | Standby tugs provide rapid response to intercept and assist ships in distress which can prevent incidents from becoming accidents or spills. |
| Vessel traffic services | Domestic | Prevention | Provides vessel traffic management, not unlike air traffic controllers. Vessels are required to identify themselves upon entering Canadian waters and provide regular check-ins. |

Source: IHS CERA, Wave Point Consulting Ltd.

1. These measures all fall under the auspice of International Convention for the Prevention of Pollution from Ships (MARPOL).

# ANNEX C: IHS MARITIME REGIONAL TANKER ACTIVITY AND INCIDENT AND SPILL DATA

**Table C-1**

**Annual port callings of tankers in select jurisdictions in 2012[1]**

| | Small tankers | | | Large tankers | | |
|---|---|---|---|---|---|---|
| Country/region | Coastal | Handy[2] | Panamax | Aframax | Suezmax | VLCC & larger |
| China | 23,147 | 17,234 | 1,646 | 862 | 155 | 1,002 |
| Australia | 977 | 706 | 1,827 | 19 | 817 | 95 |
| Norway | 3,417 | 1,369 | 54 | 281 | 182 | 11 |
| United States | 850 | 31,029 | 4,220 | 9,704 | 3,218 | 696 |
| East Coast | 61 | 4,593 | 784 | 653 | 249 | - |
| US Gulf Coast | 707 | 24,148 | 2,878 | 8,567 | 1,584 | 612 |
| West Coast[3] | 82 | 2,288 | 558 | 484 | 1,385 | 84 |
| Canada[4] | 403 | 2,766 | 146 | 236 | 358 | 60 |
| East[5] | 403 | 2,377 | 97 | 182 | 358 | 60 |
| West | - | 389 | 49 | 54 | - | - |

Source: IHS Maritime.

1. A port calling is defined as a ship arriving, berthing, and sailing and is counted as one call.
2. Handy size category includes up to Medium Range (MR) tankers (to everything smaller than Panamax).
3. US West Coast includes movements in the State of Alaska. In 2012 there were 588 movements; 263 were large tankers up to Suezmax which singularly accounted for 244 of these movements.
4. Canada has tanker movements on the great lakes that are not included here. In 2012, there were an estimate 1,362 small tanker port callings (no large tanker).
5. Canadian East Coast port callings include those that occur in the St. Lawrence.

**Table C-2**

**Occurrence of incidents and spills from 1993 to 2012 for large double hull tankers**

| Location | | At sea | | Territorial and inland waters[1] | | In port or harbors | |
|---|---|---|---|---|---|---|---|
| | | Incident | Spill | Incident | Spill | Incident | Spill |
| Cause of incident (and spill) | Collision or contact | 55 | 3 | 42 | 3 | 55 | 5 |
| | Machinery (or hull) failure | 71 | | 17 | 1 | 25 | 1 |
| | Grounding | 23 | 1 | 44 | 2 | 10 | |
| | Fire/explosion | 7 | | 2 | | 13 | |
| | Break-up | 4 | | 1 | | 3 | |
| | Other | 3 | | 0 | | 1 | |
| **Total** | | **163** | **4** | **106** | **6** | **107** | **6** |

Source: IHS Maritime.

1. Includes coastal waters, rivers, canals, and fjords.

IHS Markit®

# Canadian crude logistics

3 August 2021

**Celina Hwang**
Director

**Kevin Birn**
Vice President

Crude oil markets | **Strategic Report**

# Contents

# Canadian crude logistics

Although it is not well-known, Canada is the third-largest exporter of crude oil globally. Owing to its geography, Canada also relies on crude oil imports to meet domestic demand. Meeting regional supply and demand as well as those in export markets has resulted in a complex crude oil logistics system. However, knowledge about where, how much, and by what mode crude oil is handled differs across Canada. This report explores the key issues surrounding the current and future outlook of how oil moves in Canada—that is, Canadian crude oil logistics.

## Key implications

- **IHS Markit estimates that in 2019, Canada handled about 6.6 MMb/d—2.0 MMb/d more than it produced.*** Handled is defined as long-distance movement of imports, exports, and internal transfers of crude oil and condensates. This does not include any shorter distance movements such as upstream gathering.

- **Because of crude quality and Canadian geography, regions that are distant from its oil production rely on imports, internal transfers, and reexports (where Canadian production went through the United States and then went back into Canada) to meet demand.** In 2019, IHS Markit estimates Canada imported over 850,000 b/d of crude oil, internally transferred over 1.2 MMb/d, and transferring through the United States approximately 480,000 b/d.

- **Pipelines represent the backbone of the Canadian crude oil logistical system, accounting for about four-fifths or 5.4 MMb/d of the long-distance movements in 2019.** The next largest mode of transport was marine, which handled 14% of movements by volume almost exclusively on the east coast. Crude-by-rail accounted for about 5% as it proved to be a critical backstop as western Canadian pipeline export capacity has struggled to keep up with demand.

- **Looking forward, pipelines will remain the dominant mode of transportation; however, with increased pipeline capacity to the west coast, a rise in tanker movements is also expected.** IHS Markit estimates by 2025, total crude oil volumes handled in Canada could increase by over 650,000 b/d to over 7.3 MMb/d. Most of these movements are expected to occur in western Canada via greater overland pipeline and marine exports.

*Because of the 2020 global pandemic and the resulting extreme market disruptions, 2019 was used for the historical analysis included in this report.

—3 August 2021

# Canadian crude logistics

**Celina Hwang,** Director

**Kevin Birn,** Vice President

## About this report

**Purpose.** There are differences of opinion about Canadian crude oil transportation infrastructure, experience handling crude oil, and the demand for the expansion of export pipeline capacity. This report explores Canada's experience handling and moving crude: how much, where, why, and how?

**Context.** Since 2009, IHS Markit has provided research on issues surrounding the development of Canadian oil sands. This report is part of a series of reports from the IHS Markit Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content. Because of the 2020 global pandemic and the resulting extreme market disruptions, the year 2019 was used for the historical analysis included in this report. This report considers the long-distance transportation of both crude oil and condensate, but not refined products. The report does not cover movements associated with the extensive pipeline gathering systems that connect key producing fields to terminals. Pipelines connected to marine tanker terminals would be counted as separate movements provided they are long distance.

**Structure.** This report has five sections:

- Introduction
- Mind the gap: Canada's distinct supply and demand regions
- The Canadian experience moving crude oil: By pipe, ship, and railcar
- The future of crude oil logistics
- Concluding remarks

## Introduction

Canada is among the world's largest producers and exporters of crude oil. In 2019, Canada was the fourth-largest producer, the third-largest exporter, and the ninth-largest consumer of crude oil. This equated to production of 4.6 MMb/d, exports of 4.1 MMb/d, and imports of over 850,000 b/d. The scale of crude trade in Canada is therefore much greater than production alone. To meet supply and demand within Canada and abroad, it relies on an extensive logistics system.

Ninety-five percent of Canadian production occurs onshore, inland, and often in remote areas in the western Canadian provinces of Alberta and Saskatchewan. The remainder principally comes from offshore platforms off the east coast of Canada. The main consuming regions are located far from production in the more populous central regions of Ontario and Quebec. For these reasons and the country's overall geography, meeting domestic demand has historically necessitated imports.

Every day, Canada moves approximately 2 MMb/d more crude oil than is produced. In 2019, IHS Markit estimates that the long-distance transportation system, which includes pipeline, rail, and marine transport handled about 6.6 MMb/d. This is similar in magnitude to two-fifths of all North American oil refinery demand. Gathering, or small diameter that typically move production from the field to processing facilities, were not included in this transportation total. If oil gathering movements were included, the volume being handled would be much greater.

This report reviews Canada's experience moving crude oil from where it is produced, to where it goes, how it gets to its location, and whether that could change in the future.

## Mind the gap: Canada's distinct supply and demand regions

The Canadian crude oil market can be divided into three regions: the west being the largest-producing region (Alberta, Saskatchewan, and to a lesser extent northern British Columbia and southern Manitoba), the central region being Canada's main consuming region (Ontario to Quebec), and the east coast region being both a smaller producing region and consuming region than Canada's west and central regions, respectively (see Figure 1).[1]

To meet demand—both domestic and foreign—Canada transfers crude and condensate internally and through the United States, exports and imports crude oil, and processes crude oil in its various regions. Although Canadian crude oil production is over two and a half times greater than domestic demand, imports are still required to meet demand. In 2019, IHS Markit estimates that Canada produced over 4.6 MMb/d, imported over 850,000 b/d, processed via domestic refineries 1.7 MMb/d, exported 4.1 MMb/d, and transferred (internally and through the United States) about 1.7 MMb/d (see Figure 2).[2]

Despite Canada producing over 4.6 MMb/d, imports still occur for three primary reasons:

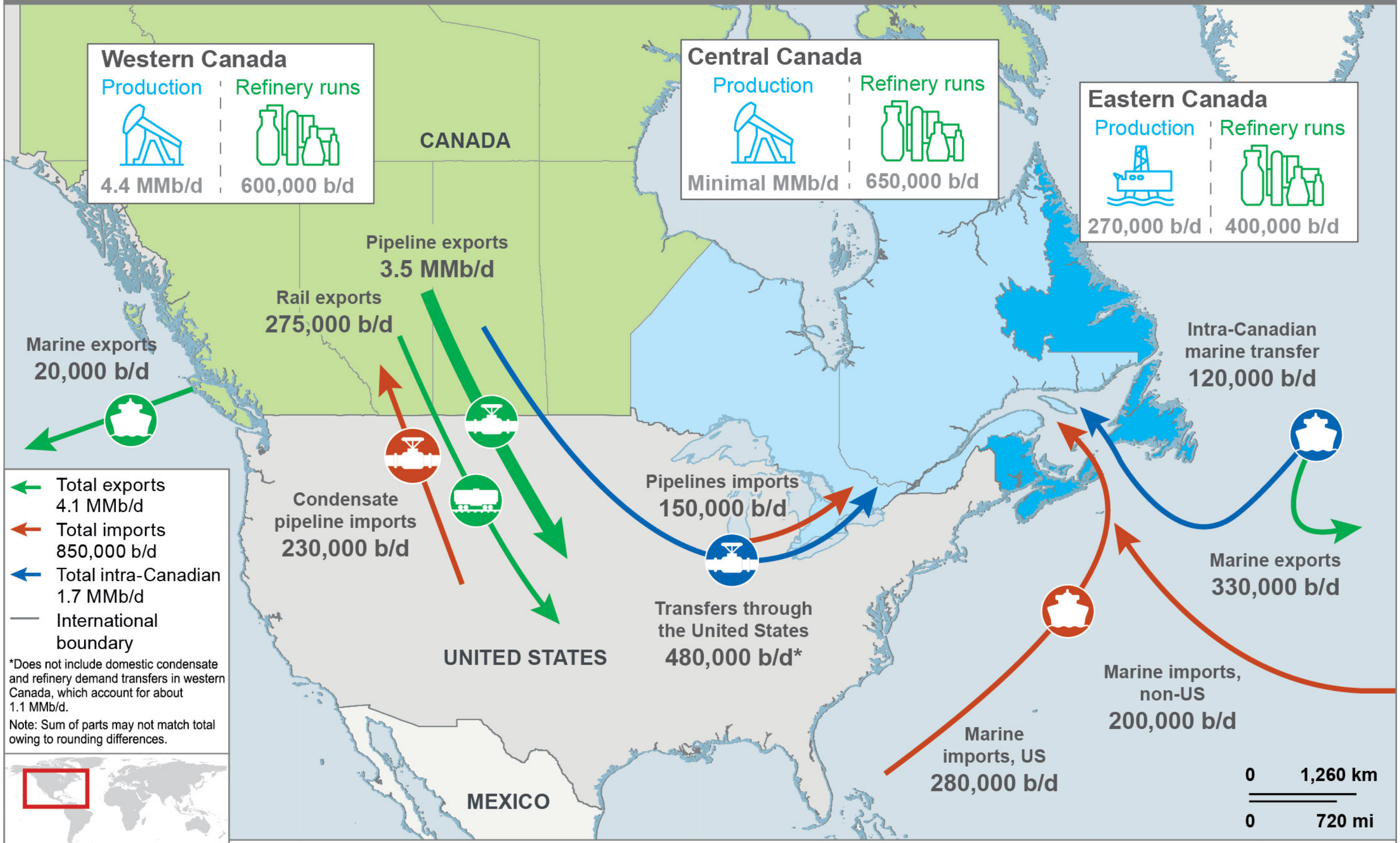
**Geography.** Canada is a geographically large nation with nearly two-thirds of its population located in its central provinces of Ontario and Quebec (principally along the Quebec City–Windsor Corridor). This region is approximately 1,800 miles (over 3,000 km) from western Canadian production. For western Canadian producers, the US Midwest is both a larger and more approximate market than central Canada. Chicago is about 500 miles (800 km) closer with oil demand of 3.8 MMb/d compared with 650,000 b/d in central Canada. As western Canadian production rose, most western Canadian pipelines were designed to connect into the US

1. Consumption of oil refers to refineries using crude oil to produce refined products, such as gasoline.

2. These numbers include both crude and condensate.

Figure 1

Canadian crude oil trade flows in 2019

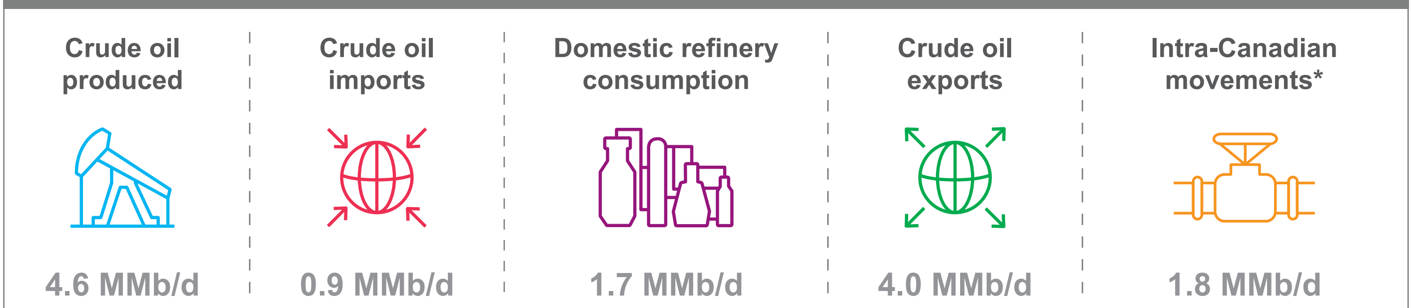



Source: IHS Markit/2003330



Figure 2

Canadian crude oil production, consumption, and movements in 2019




Note: *Transfers includes domestic transfers in western and eastern regions of Canada to regional refineries, condensate to required for oil sands blending, and transfers through the United States.

Source: IHS Markit



Midwest (PADD 2) market. With most pipeline infrastructure heading into the US Midwest, central Canadian refineries have relied on deliveries of crude oil coming up from the US Midwest as well as offshore imports via eastern Canadian and historically US ports. These deliveries include transfers of Canadian crude oil through the United States, US imports, and imports from offshore.

**Oil sands blending.** Bitumen, which is the dominant form of western Canadian production, is an extra heavy sour crude oil derived from the oil sands. In its natural state, bitumen is too viscous to be transported by pipeline. To meet pipeline requirements, bitumen is either upgraded into a light synthetic crude oil or blended (diluted) with lighter or less dense hydrocarbons. The market for diluents is significant. In 2019, about 60% of bitumen production required dilution, demanding about 750,000 b/d of diluents. The most common diluent is a pentane plus material known as condensate. Domestic demand for bitumen blending outstrips regional condensate supply and imports of condensate are required. In 2019, the oil sands imported nearly 230,000 b/d of condensate by pipeline from the United States.

**Refinery configurations.** The type of oil demanded in each region also plays a role in crude oil imports. As western Canadian output rose over the past two decades, most of the production has come from heavier, more sour crude oil, which requires specialized heavy oil processing units in order to be economically processed. US Midwest refineries invested in these heavy processing units to take advantage of growing western Canadian heavy oil, while refineries in Ontario and Quebec remained geared toward lighter crude grades. In 2019, refineries in central and eastern Canada demanded about 1.1 MMb/d of which over four-fifths was lighter oil. In comparison, the US Gulf Coast (USGC) refinery complex is only modestly farther away (approximately 2,200 miles compared with 2,000 miles or approximately 3,500 km compared with 3,000 km away from western Canadian production) and was both significantly larger (nearly 9 MMb/d on average in PADD 3 versus 650,000 b/d for Ontario and Quebec) and already configured to consume significant volumes of heavy sour crude oil. In 2019, the USGC processed about 1.9 MMb/d of heavy sour crude oil. This presented both western Canadian producers and USGC refineries with an attractive solution. This has led to and continues to lead to projects that would further expand pipeline capacity from the US Midwest and western Canada to the USGC region.

## The Canadian experience moving crude oil: Pipe, ship, and railcars

Canada moves over 6.6 MMb/d of crude oil from domestic production to domestic and US refineries and other export markets, as well as imports of condensate for oil sands blending and crude oil bound for central and eastern refineries. For this to occur, Canada relies on an extensive long-distance logistics system composed of thousands of miles of transmission pipelines, an extensive rail system, and marine handling capability to manage maritime tankers and barges on both coastlines. Each mode represents a critical link in a chain that ensures an uninterrupted supply, enabling trade, energy production, processing, and consumption. However, Canada's reliance and familiarity with crude oil transportation modes vary across its diverse regions. This section discusses Canada's familiarity with each mode. See Appendix A–C for additional details related to pipe, tanker, and crude-by-rail.

### Pipelines form the backbone of Canadian crude logistics

Pipelines predate the Canadian confederation. The first pipeline was built in 1862 to connect an oilfield in Petrolia, Ontario to Sarnia, Ontario.[3] Today, pipelines are the dominant mode of crude oil transportation in Canada. Canada also makes use of other modes including rail, tanker, barge, and even trucks.[4] IHS Markit estimates in 2019, that Canada moved about 6.6 MMb/d or about 2.4 billion barrels a year.

As shown in Figure 3, pipelines account for the majority of long-distance crude oil movements in Canada. Most pipelines originate in western Canada and head southeast into the US Midwest. Some pipelines, in turn, head back from the US Midwest into central Canada, and others move further south connecting to Cushing, Oklahoma—the main North American crude oil trading hub—and some move further south still onto the USGC region, which is the largest processing region in North America.

Long-distance transportation pipelines accounted for four-fifths of all Canadian crude oil movements in 2019. About two-thirds of these movements were for export. Under a-third of movements were intra-Canadian

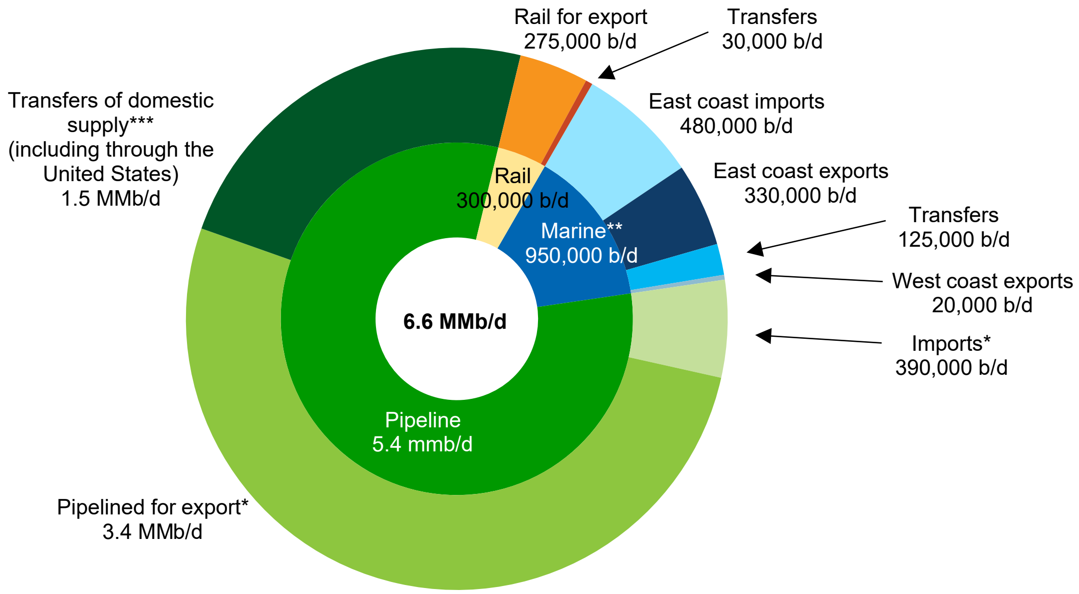
3. See About Pipelines, "How long have pipelines operated in Canada?", https://www.aboutpipelines.com/en/pipeline-101/pipeline-history/.

4. Trucks are not accounted for as part of the totals in this report because they would be considered short distance and part of the field gather system.

Figure 3

**Estimate of Canadian handling of imports, exports, intra-Canadian crude within Canada in 2019 (does not include gathering)**




Note: *Onshore internal gathering, transfering, storage is not included. Long-distance offshore transfers from producing fields to terminals are included. **Marine includes both Canada east and west coast. International crude transfers, lighering, and barging within Canadian waters are not included. *Includes transfers of crude oil for offshore export via the Port of Vancouver. **Includes US imports into Ontario and condensate in western Canada. ***Includes internal transfers of domestic crude oil and condensate to western Canadian refineries and oil sands operations and transfers exiting western Canada transiting through the United States to Ontario.

Source: IHS Markit, National Energy Board and various other sources

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transfers for western Canadian crude traveling through US PADD 2 to the central Canada refining region. Less than one-tenth of these movements, but still significant volumetrically at about 390,000 b/d, were imports from the United States going to either refineries in Canada's central and eastern regions or imports of condensate into western Canada for bitumen blending.

Most crude oil exports and pipeline movements are handled by the Enbridge Canadian Mainline system and TC Energy's Keystone system (see Figure 4). In 2019, these two systems collectively transported nearly four-fifths of all western Canadian exports and over two-fifths of total Canadian movements (imports, exports, and intra-Canadian movements). The other major existing pipelines—Trans Mountain, Plains Midstream's Rangeland, Inter Pipeline's Milk River, and Enbridge's Express account for the remainder. Except for the Trans Mountain system, all these pipelines transport crude oil to the United States.

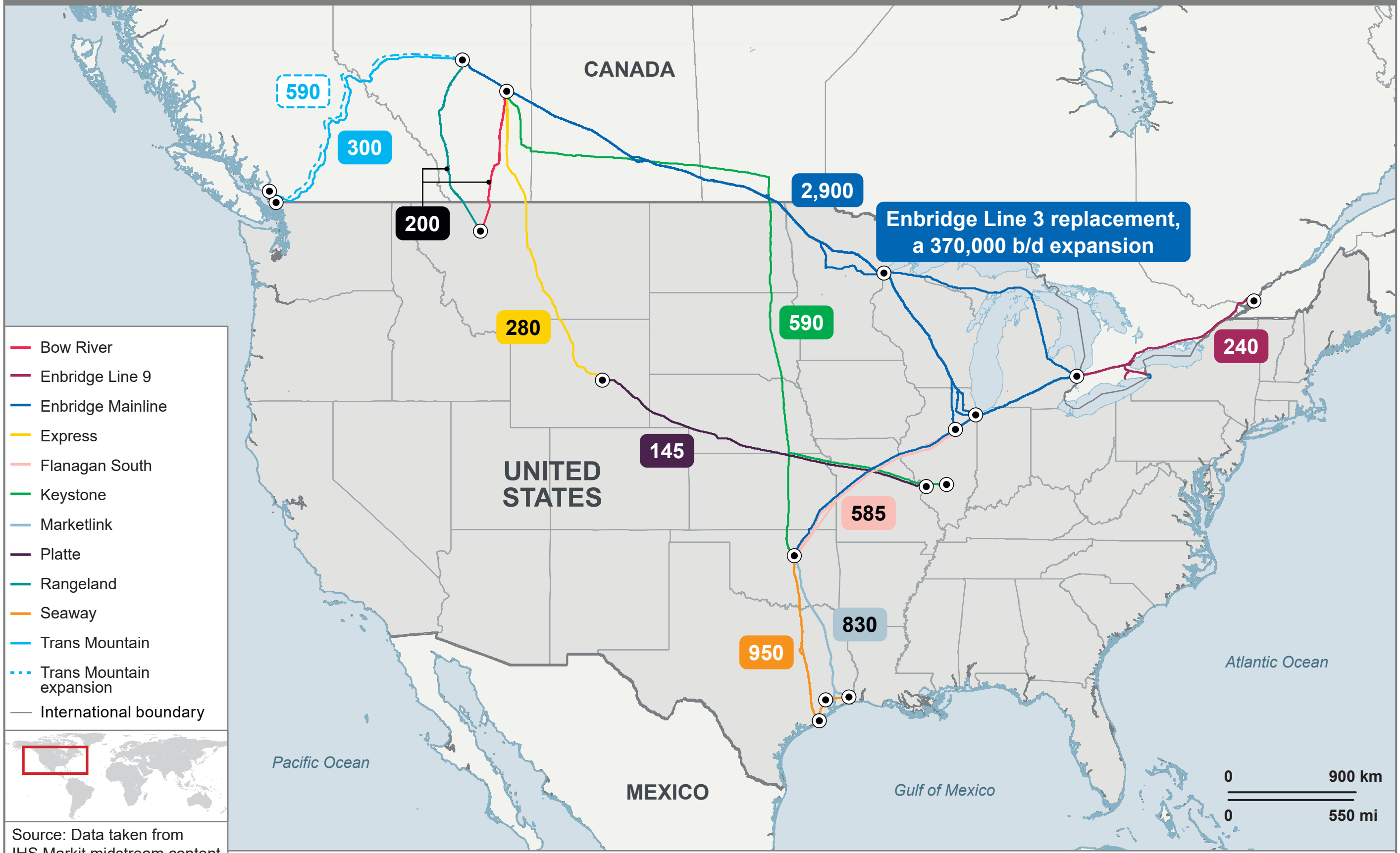
The Trans Mountain pipeline is the only western Canadian pipeline capable of accessing tidewater on its own. However, the majority of the capacity on the Trans Mountain pipeline has been taken up to support transfers of crude oil and refined products to the Vancouver area and pipeline exports to Washington state. Little room remains for offshore exports at this point (see Figure 5).

## Marine transport occurs principally off Canada's east coast

Marine tanker transport is the second most common mode of crude oil transportation in Canada (although it is the most common globally). In 2019, about 15% of total Canadian crude movements, or 950,000 b/d, were handled by marine vessels. Marine movements in this context typically employ Aframax and Suezmax class size vessels capable of holding 750,000 bbl to 900,000 bbl (see Figure 6). Smaller coastal tankers and barges, of which there are a vast number that make numerous short-haul trips along both the west and east coasts, are

Figure 4

**Existing and proposed pipelines departing western Canada (thousand b/d)**




Source: Data taken from IHS Markit midstream content (EDIN): 2003350

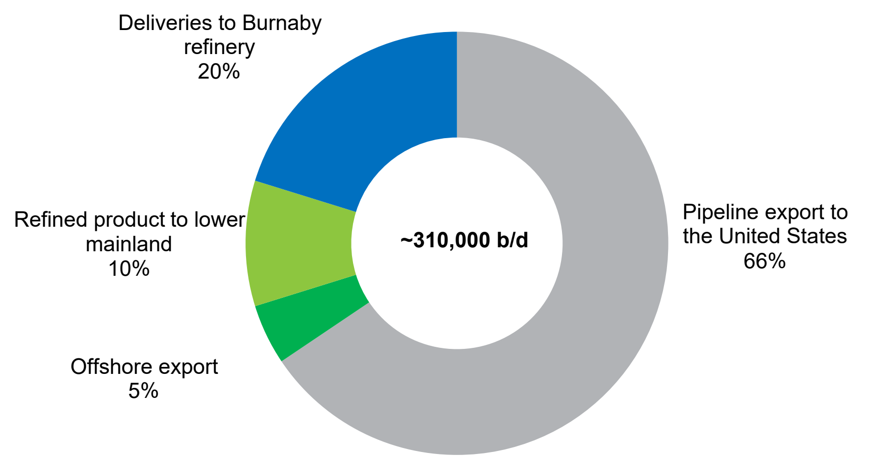


not considered in this tally because of data availability. Many of these smaller vessels are often employed for internal transfers and lightering.[5]

Almost all of Canada's large-scale marine movements of crude oil occur in the waters off the east coast of Canada. This is primarily because of there being eight refineries in central and eastern Canada, four of which have direct access to tidewater. Less than 1% of movements currently occur on Canada's west coast. In 2019, there were 295 individual crude tanker movements in Canadian waters, carrying about 350 MMbbl, or about 2.0% of total global oil

Figure 5

**Trans Mountain flows by type (2019)**



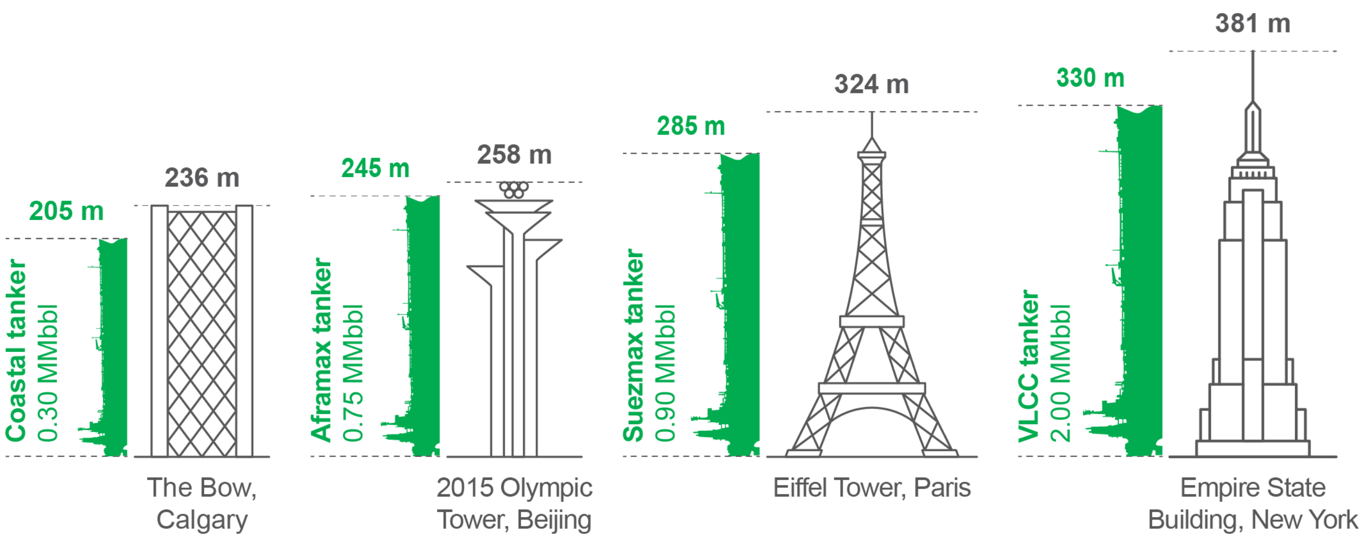

Source: Canada's Energy Regulator



5. Lightering means to transfer cargo from one ship to another. In the case of crude oil, lightering is done to move oil from a large vessel that is not able to enter a port onto a smaller vessel that is able to enter a port.

Figure 6

**Crude oil tanker size comparison**




Note: VLCC = very large crude carrier.
The ultra-large crude carrier class of tankers is not widely used, beyond storage. This vessel is approximately 415 m long and can hold up to 4 MMbbl of crude oil.

Source: IHS Markit

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marine movements.[6] Approximately half of all Canadian marine movements are imports, primarily from the United States and heading to refineries via the Port of Quebec, Quebec and Saint John, New Brunswick. Just over one-third of marine movements are for export from Canada's east coast offshore fields, principally to markets in the United States and Europe. Over 10% of large, long-distance movements are intra-Canadian, which include transfers from east coast offshore production platforms to the marine terminal at Whiffen Head in Newfoundland and refineries in Canada's eastern region.

## Crude-by-rail fills a critical gap in Canadian export capacity

Crude oil exports by rail have risen in recent years as western Canadian output has exceeded regional pipeline export capacity. In 2019, the railroads handed nearly 5% of all Canadian movements or about 300,000 b/d.[7] Nearly all rail movements were for export to the United States, predominantly moving to the USGC from western Canada with a small volume being moved within Canada (see Figure 7). The impact of COVID-19 led to a dramatic albeit temporary drop in western Canadian output, which collapsed crude-by-rail movements in 2020. The manufacturing-style nature of oil sands operations, where the underlying resource is plentiful and output is limited by processing capacity, dominates Canadian output and has allowed production to more than recover to previous yearly levels.[8] The resumption of oil sands output, coupled with the fact that some conventional heavy sour operations have long made use of rail, resulted in a modest recovery of crude-by-rail movements over 2021. Should pipelines currently in construction—Enbridge Line 3 Replacement and Trans Mountain Expansion (TMX)—be completed as scheduled, crude-by-rail exports may never again reach the historical heights, but they are expected to remain a facet of western Canadian exports. Some western

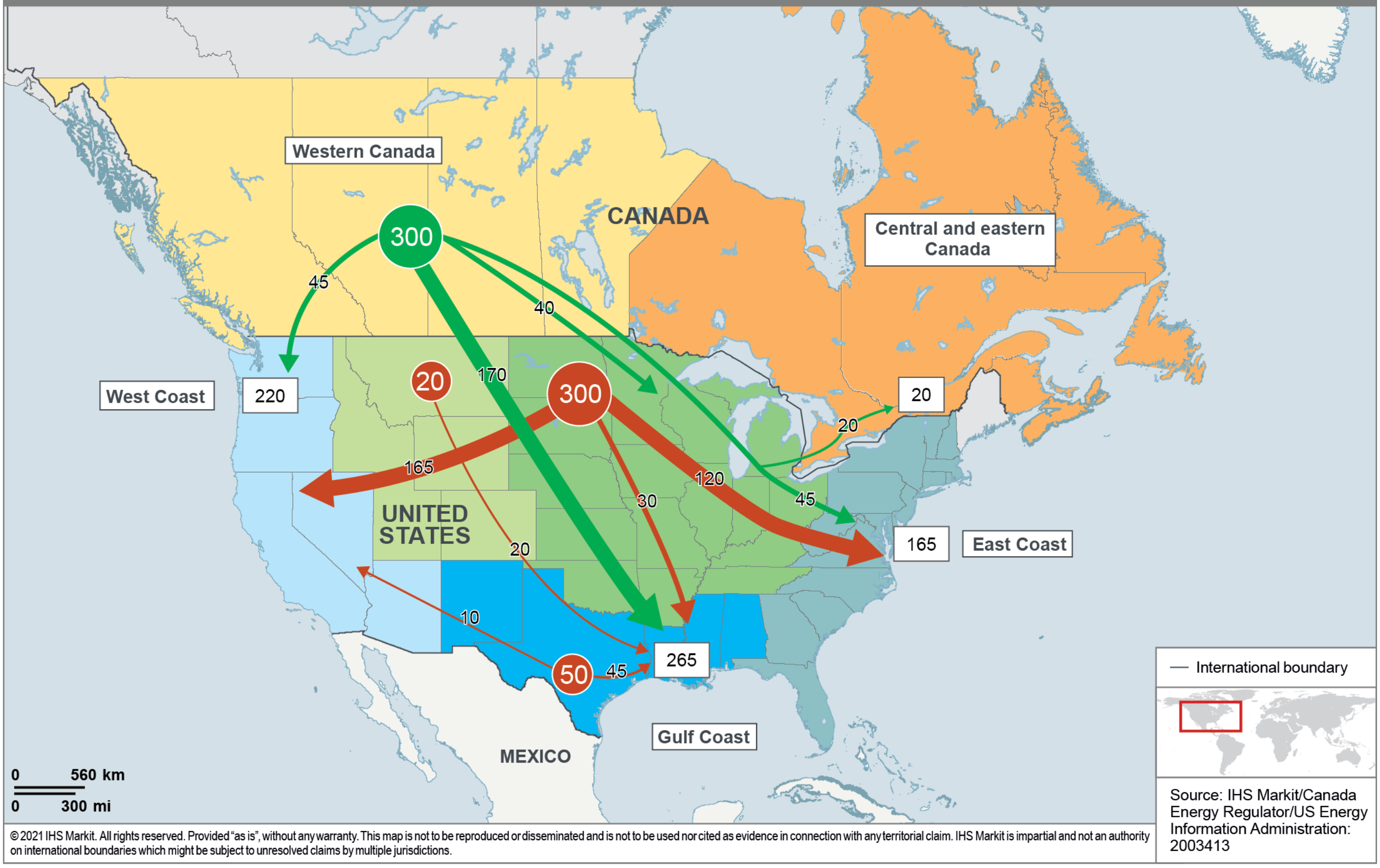
6. This total does not include coastal tanker movements, which are used for short-haul trips along the coast.

7. After reaching record levels of over 400,000 b/d in early 2020, the temporary, albeit dramatic, COVID-19-led production shut-in of second quarter 2020 collapsed rail movements to record lows.

8. For more information see IHS Markit blog, "Canadian oil sands running above pre-pandemic highs, but the lingering impacts of COVID-19 and acceleration of energy transition have lowered the growth prospects", 23 June 2021, https://ihsmarkit.com/research-analysis/canadian-oil-sands-running-above-prepandemic-highs.html

Figure 7

**Major movements of North American crude by rail in 2019 (thousand b/d)**




Canadian operators have already invested in crude-by-rail capacity, which can provide the benefit of reaching refineries that are unconnected to overland pipeline systems.

## Future of Canadian crude logistics: More pipe and tankers

Since the price collapse in 2014–15, Canadian crude oil supply has continued to increase as Canadian projects under construction were completed and brought online. This includes mega oil sands projects such as the Fort Hills mine as well as the large gravity-based offshore project, Hebron. In western Canada, from 2015 to 2019, crude oil supply increased by nearly 650,000 b/d. However, over this same period, IHS Markit estimates the effective western Canada pipeline export capacity only increased by 340,000 b/d. Although the impacts of the COVID-19 demand destruction are anticipated to have short- and medium-term implications on oil production in western Canada, over the next 10 years from 2020 to 2030, IHS Markit estimates that Canadian crude supply could still rise by nearly 900,000 b/d. Most—nearly four-fifths—of this growth comes from the ramp-up and optimization of the Canadian oil sands and, to a lesser extent, the completion of oil sands projects where some capital has already been invested.[9] The rise from today to the mid-2020s is particularly stable with almost all of the rise in output coming from the ramp-up and optimization of existing output. Higher levels of output will require greater movements of crude oil. As noted in Figure 8, IHS Markit estimates total movements could increase by over 650,000 b/d from 2019 to 7.3 MMb/d by 2025.

9. See IHS Markit blog, "Canadian oil sands running above pre-pandemic highs, but the lingering impacts of COVID-19 and acceleration of energy transition have lowered the growth prospects," 23 June 2021, https://ihsmarkit.com/research-analysis/canadian-oil-sands-running-above-prepandemic-highs.html

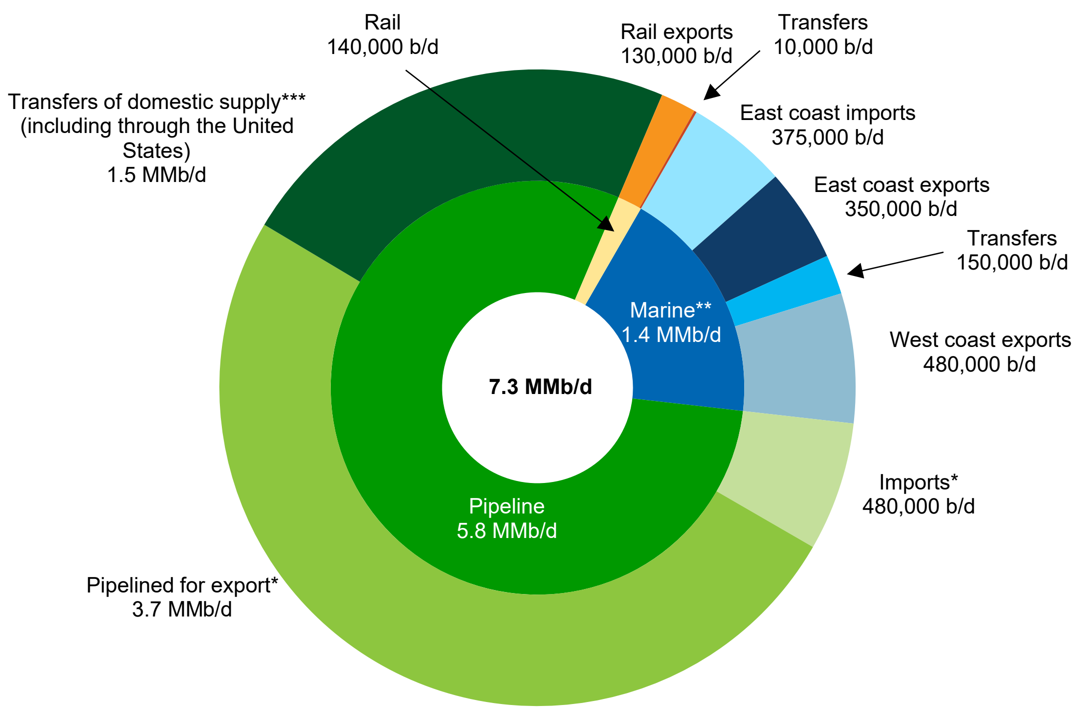
## New pipelines increase capacity and optionality for producers

Pipelines could see the greatest increase, followed by marine, while the system's reliance on rail has the potential to decline (depending on the timing of advancing pipelines). However, on a percentage basis, long-distance tanker movements could see the greatest rise—nearly doubling—as a result of the expansion of existing pipeline capacity to Canada's west coast. On the pipeline side, advancing projects have long suffered from delays. Currently two large long-distance pipelines projects—Enbridge Line 3 Replacement and TMX—are in construction that could add nearly 900,000 b/d of incremental capacity over the short to medium term.[10] Despite the potential improvement in pipeline export capacity, rail is expected to remain a key part of the western Canadian export system. However, the completion of these pipelines and optimization projects are not set-in-stone and delays to the in-service dates may occur that could result in greater movements of crude-by-rail than currently anticipated.

Moreover, in addition to assumptions regarding advancing pipeline projects, this report analysis (as shown in Figure 8) also assumes all existing in-service pipelines remain in-service. However, in recent years, existing pipelines have also come under greater scrutiny and even opposition. Canada's central regions of Quebec and Ontario continue to rely on pipeline imports of US crude oil and transfers of Canadian crude oil through the US Midwest to meet regional refinery and heating demand. The state of Michigan in recent years has sought

Figure 8

**Estimate of Canadian handling of imports, exports, and intra-Canadian crude within Canada in 2025 (does not include gathering)**




Note: *Onshore internal gathering, transfering, storage is not included. Long-distance offshore transfers from producing fields to terminals are included. **Marine includes both Canada east and west coast. International crude transfers, lighering, and barging within Canadian waters are not included. *Includes transfers of crude oil for offshore export via the Port of Vancouver. **Includes US imports into Ontario and condensate in Western Canada. ***Includes internal transfers of domestic crude oil and condensate to western Canadian refineries and oil sands operations and transfers exiting western Canada transiting through the United States to Ontario.

Source: IHS Markit, National Energy Board, and various other sources



10. The Keystone XL pipeline was put on hold after President Biden revoked the cross-border permit on 20 January 2021. The pipeline was subsequently canceled by TC Energy on 9 June 2021.

to shut down one of these critical connectors—Enbridge Line 5 pipeline, which transfers light crude oil and natural gas liquids through to Michigan and into the surrounding United States and Canada's central regions. Any disruption of existing infrastructure could have significant implications to the Canadian and broader North American crude oil logistical system, and energy security.[11]

### Tankers on the west coast set to rise

Less than 1% of Canadian tanker movements occurred on Canada's west coast in 2019. In total, only eight tankers visited the Port of Vancouver in 2019, all of which were loaded with crude to be exported. Four of the tankers were destined for Asia and the remainder to the United States. Although Canadian movements are relatively low on its west coast, Cherry Point and Anacortes, two of the major ports in Washington state, handled about 165 tanker movements in 2019.

To access new markets for the western Canadian oil industry, the TMX is currently under construction. TMX would twin an existing pipeline from Edmonton, Alberta to the Westridge Marine Terminal in Burnaby, British Columbia in the Port of Vancouver. This would lead to a rise in both pipeline movements to and tanker movements from the west coast of Canada. When complete, crude oil transportation capacity to the west coast would increase by 590,000 b/d to nearly 900,000 b/d. It is estimated tanker movements from the Port of Vancouver could increase to 400 movements a year.[12]

## Concluding remarks

Over the past decade, the movement of crude oil in Canada and other nations has come under heightened scrutiny. However, it is often less understood precisely where, how, how much crude oil is handled, and why. In Canada, pipelines have dominated the long-distance movement of crude oil, principally for export, followed by tankers and rail.

Looking forward, we anticipate Canada's handling of crude oil will increase. By 2025, total movements could increase by 650,000 b/d, largely underpinned by domestic production increases with four-fifths of the rise coming from the ramp-up and optimization of existing facilities.

The majority of these new movements will be handled by pipeline, but marine tanker traffic is also likely to rise. While the majority of tanker movements will continue to occur in the east coast offshore, pipeline and then subsequently tanker movement for export are set to rise from Canada's west coast. Although crude-by-rail has proven capable of moving large qualities of crude oil and is expected to remain an important mode of transportation, it may never again reach historical heights.

Pipelines, crude-by-rail, and marine movements all play an important part in the movement of Canadian crude oil. This report sought to review the role of each mode in ensuring Canada can meet its energy demand each day, as well as key exports markets' demand for Canadian crude oil. Safety is also a key area of interest focused on the transportation of crude oil. Although this was not the focus of this report, there is a brief discussion in the appendices.

11. For more information on Line 5 see: IHS Markit blog, Potential NGL impacts of Enbridge Line 5 shutdown are substantial, 7 May 2021 and Line 5 shutdown could create a logistical scramble, reducing competitiveness of crude oil producers and refiners, 7 May 2021.

12. Trans Mountain estimates that the expanded terminal would handle 37 vessels per month: 34 Aframax and three barge vessels. See Transmountain, "Marine Plans", https://www.transmountain.com/marine-plans.

# Appendix A: Pipelines are the backbone of Canadian crude transportation

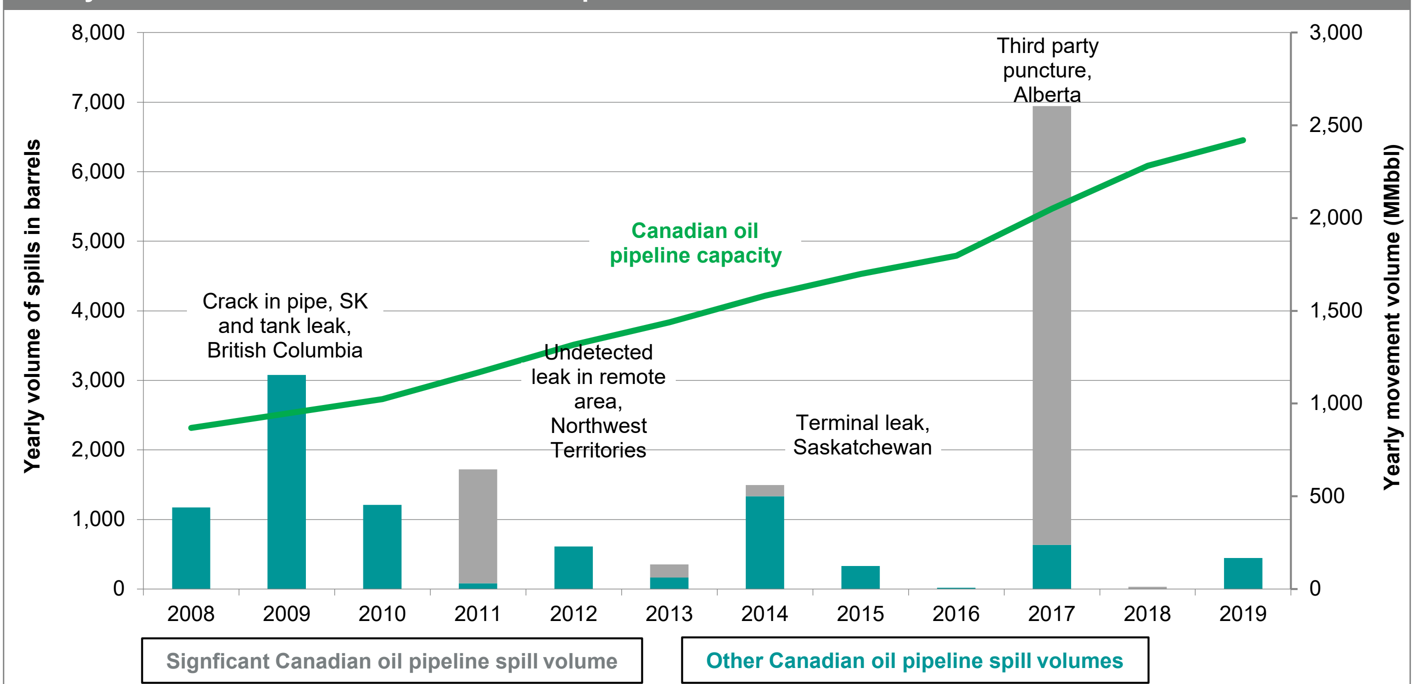
Pipelines have emerged as the dominant form of overland crude oil transport. Canada has an expansive network of pipelines, the majority of which originate in western Canada and head south into the US Midwest. Some pipelines, in turn, head back from the US Midwest into central Canada, while others move further south to the USGC region. There are also gathering and intraprovincial pipelines that move oil from wells to processing facilities, storage tanks, and long-distance transmission systems. Transmission pipelines, or large diameter pipelines, move higher volumes of crude oil, over greater distances than gathering lines. These pipelines are typically buried 3–6 feet (1–2 meters) below the surface, which provides shippers greater predictability than other overland modes of crude oil transportation, such as truck or rail, because movements are largely unimpeded by weather or other external factors. Conversely, pipelines are less flexible, providing a fixed capacity over a fixed route, whereas rail, for example, can more quickly scale capacity up or down based on regional supply and demand opportunities and move to and from different geographies using an established rail network.

## Pipeline safety

As the volume of crude oil transported in Canada increased over the past decade, there have been increasing concerns over the ability to safely transport it by pipelines, with concerns being expressed over potential leaks and ruptures. Data from the Canada Energy Regulator (CER) of incidents involving the unintentional release of crude oil from major long-distance pipelines indicate that as the volume of movements has increased the number of incidents has declined. This is shown in Figure A-1.

Figure A-1

Yearly volume of crude oil and condensate spill incidents in Canada




Note: Spill volume percent of total pipeline volume ranged from 0% to 0.34% with the average being 0.11%.
Source: IHS Markit, Canadian Energy Regulator



Most spills associated with major export pipelines occur within the containment areas of terminals or pumping stations. When spills do occur, operators are required to have in place emergency response plans to shut down operations, contain, respond, and remediate spill sites, including the recovery of spilled volumes.

In some instances, the cause of a spill is arguably not in the control of the operator. For example, the large spill shown in Figure A-1 in 2017 occurred in a petrochemical industrial area in Sherwood Park, Alberta when a third party punctured the Enbridge Line 2 pipeline (a 24-inch pipeline) while drilling across the pipeline's right of way. Of the nearly 6,300 bbl of condensate released, most of the liquid was recovered.[13]

13. See the full investigation report from the Transportation Safety Board of Canada.

## Appendix B: Marine movements predominantly on one coast

Marine transportation is the most common form of crude oil transport globally. In 2019, IHS Markit estimates nearly 40 MMb/d of crude oil and condensate were moved globally.[14] Marine transport is the most efficient form of long-distance crude oil transport. It provides greater flexibility than other modes, allowing producers to move their crude from regions that may be better supplied and realize lower prices to regions that may be in more demand and thus the ability to obtain higher prices.

In marine shipping, larger vessels generally benefit from greater economies of scale (higher absolute cost but greater capacity thus reducing the unit cost). Generally, smaller vessels are often used for shorter distances and have greater access to ports due to smaller size. Marine tanker size can range significantly. Short- to medium-distance vessels include the Panamax tanker, the Aframax tanker, and the Suezmax tanker, which range from 250 m to 290 m in length and can carry 0.75 MMbbl to 0.9 MMbbl of crude oil. The scale of some of the largest classes of vessels, such as the very large crude carrier (VLCC), are so massive they are restricted in terms of which ports they can access. These vessels may often be lightered offshore—where the cargo is unloaded into smaller vessels capable of reaching the final destination.

### Marine safety

The marine transportation of crude oil and associated potential environmental risk should a spill occur has long been a source of concern to coastal communities. The issue of spills is not isolated to crude oil tankers. As the scale of global trade has increased and marine vessels gained scale, the volume of fuel on vessels has also grown. All major ocean-going vessels, such as tugboats, ferries, and bulk carriers, can carry significant fuel onboard. The amount can be significant—from 40 boe to well over 300,000 boe—the upper end being similar in volume to a small coastal tanker.

A survey of global tanker incidents indicates that despite a rise in the global transport of crude oil over the past several decades, the occurrence of both spills and spill volumes declined into the early 2010s where they have remained relatively low, as noted in Figure B-1. The major drivers have been improvements to tanker technology and tanker operations, including the adoption of double-hulled tankers, improved navigational systems, increased monitoring and enforcement, and requirements for crew competency to name a few.[15]

Over the past decade, on average, less than 0.2% of total crude oil volume moved was spilled.[16] When a spill has occured they are typically relatively small and contained. Over the past decade, there was only one incident of a large-scale event. In January 2018, *Sanchi*, a suezmax class tanker laden with 950,000 bbl of condensate (an ultra-light crude oil), collided with a cargo ship off the coast of China. The tanker caught fire and burnt before sinking a week later. The official investigation cited both vessels as failing to comply with proper look-out and to make a full appraisal of the situation and risk of collision.

In Canada, there have been no major incidents involving the transportation of crude oil in the past two decades. However, there were two notable incidents involving the discharge of marine transportation fuels from non-tankers: in 2015, MV *Marathassa*, a bulk carrier on its maiden voyage from Japan to Canada released 2,700 liters of bunker fuel owing to a design defect near the Port of Vancouver off the Coast of British Columbia, and in 2016, when tug *Nathan E. Stewart* and tank barge DBL 55 ran aground near Bella Bella, British Columbia and sank, releasing 110,000 liters of diesel fuel.[17]

14. IHS Markit Commodities by Sea, https://ihsmarkit.com/products/commodities-at-sea.html.

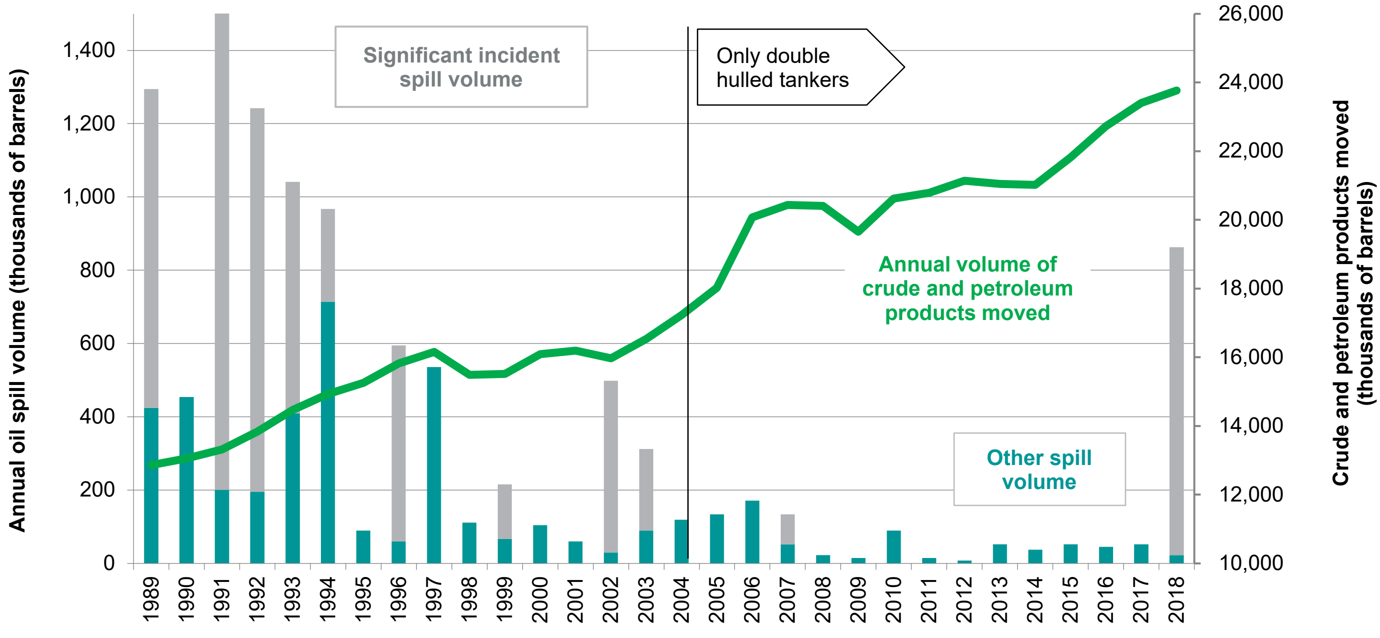
15. For more information on the transformation of the shipping industry, see the 2013 Canadian Oil Sands Dialogue special report.

16. 2019 is the last year of available data from ITOPH for marine oil spills.

17. Information on MV *Marathassa* can be found here. Information on tug *Nathan E. Stewart* can be found here.

Figure B-1

**Global frequency and volume of crude oil spills from total volume shipped**



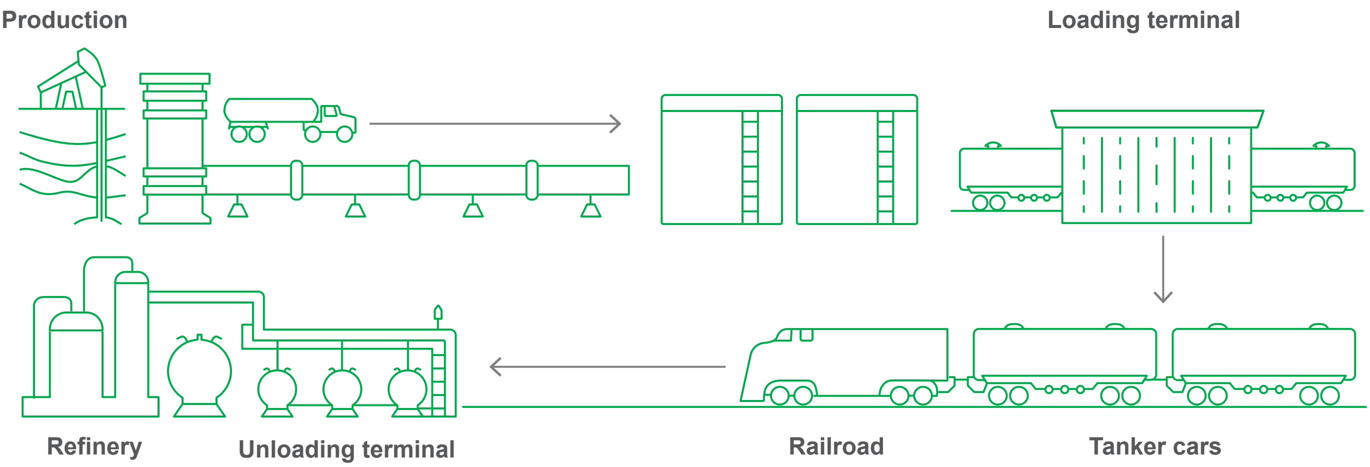

Source: IHS Markit, UNCTADStat, ITOPF

# Appendix C: Crude-by-rail provides a critical hedge for western Canadian producers

Although crude-by-rail handled the least volume over the past few years, its importance and role in being able to balance the western Canadian oil market have increased. However, it comes at a greater transportation cost and is arguably more complex from a shipper's perspective. Crude-by-rail involves multiple components, as noted in Figure C-1, including loading/unloading terminals, specialized railcars known as tank cars, and the railroads to provide the horsepower and tracks to move the cars and thus oil to the market. Compared with pipelines, as an overland transportation method, crude-by-rail is relatively more expensive. Additionally, the two primary types of contracts—manifest and unit—impact the economics of crude-by-rail. Manifest trains can carry several types of cargo and can stop at multiple locations along their way prior to the cargo reaching the final destination—this adds time and thus cost for shippers. Dedicated crude trains, known as unit trains, consist of approximately 100–120 cars that move directly from origin to destination. This results in lower transportation costs for shippers compared with manifest trains. However, from the railroad perspective, this requires dedicated capacity and may require fixed-term contracts from shippers to justify the capital outlay. However, with a system of over 280,000 miles of track, railroads offer greater flexibility and ability to reach more distant refineries that may have less pipeline connectivity. However, being susceptible to surface issues such as weather and track congestion, crude-by-rail has greater potential for disruption than pipeline.

Figure C-1

**Components of moving crude by rail**




Source: IHS Markit

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## Crude-by-rail safety

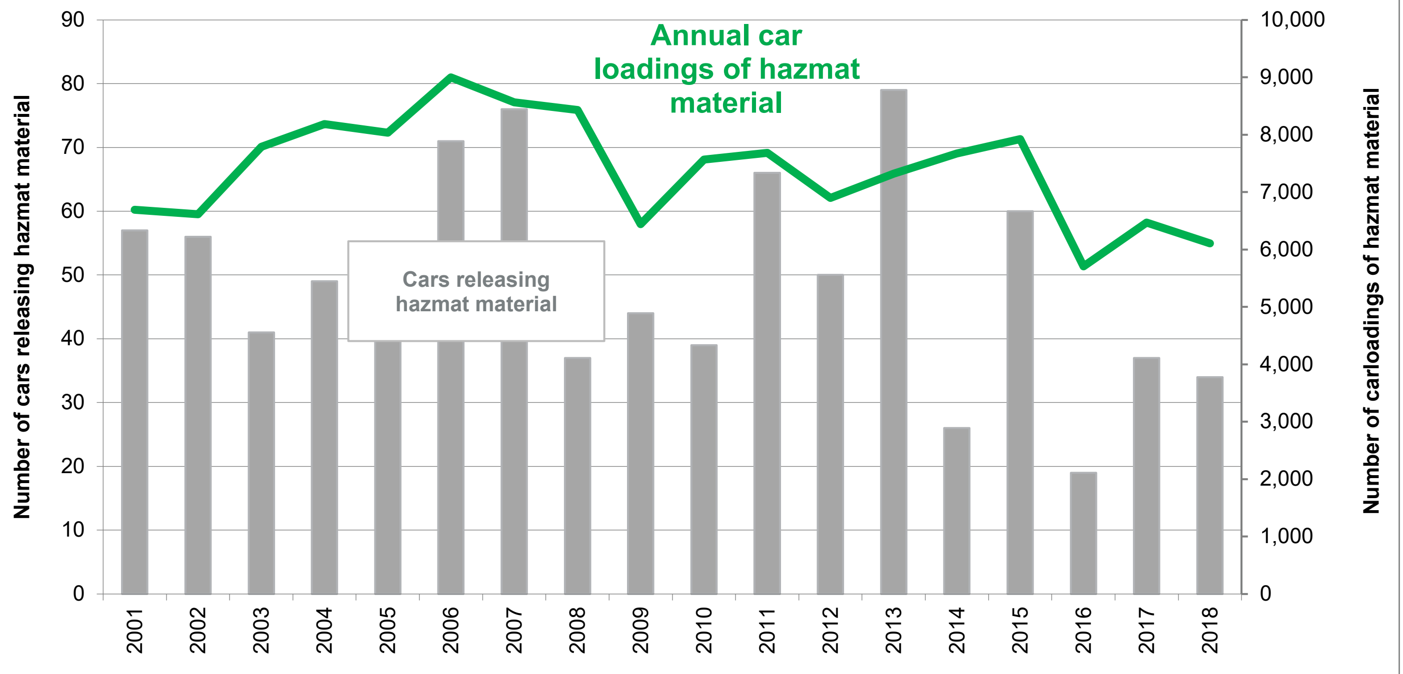
Rail safety data are not gathered about specific commodities in Canada and the United States. Rather, the classification of goods is used. Crude oil is categorized as a "hazardous material" in the United States and a "dangerous good" in Canada. These categorizations include other substances such as chlorine gas, hydrochloric acid, and molten sulfur, which complicates the understanding of crude-by-rail safety. Additionally, there are subtle differences between Canadian and US rail safety statistics that can make direct comparison difficult. For these reasons, as well as the United States being a much larger market with a higher number of movements, we made use of US safety data.

US data indicates that both the number of incidents and the number of rail cars involved in an incident have trended downward in the past two decades. There is a difference between an incident that poses the potential for a release and an actual release of hazardous material. As noted in Figure C-2, over the past couple of years the number of cars releasing hazardous material have declined.

Over the past half-decade, there have been a number of high-profile accidents involving crude-by-rail in North America. Most notably, the tragic incident in Lac-Mégantic, Quebec that involved a train carrying approximately 50,000 bbl of light sweet crude oil from North Dakota that caught fire and exploded. This incident led to the death of 47 people. In response to this and other incidents, the industry and regulators advanced increasingly stringent safety measures for the transport of crude oil by rail. Some examples include introducing speed limits, special routing measures, and phasing out older style tank cars in favor of heavier, more robust tank cars with thermal barriers.[18,19] The introduction of the new DOT-117 (TC-117 in Canada) tank car includes double hulls, front and back head shields, thermal insulation, top and bottom valve protection, and heavier/thicker steel—essentially armoring up the cars to improve their resiliency in the event of an incident.[20]

Figure C-2

**Railway hazmat release incidents and total hazmat carloadings**




Source: IHS Markit, Federal Railroad Association

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18. Canadian regulators have moved to phaseout older style tank cars on an accelerated timeline from early 2020 to early 2019. https://www.canada.ca/en/transport-canada/news/2018/09/transport-canada-speeds-up-removal-of-least-crash-resistant-rail-tank-cars-from-service.html

19. US Department of Transportation, "Fleet Composition of Rail Tank Cars Carrying Flammable Liquids: 2019 Report". https://www.bts.dot.gov/sites/bts.dot.gov/files/docs/browse-statistical-products-and-data/surveys/annual-tank-car-facility-survey/227571/tankcarreport2019.pdf

20. See: Infographic - TC-117 Tank Car.

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# A New Look

Extracting economic value from the Canadian oil sands

November 2017

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Crude Oil Markets | **Strategic Report**

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# A New Look

## Extracting economic value from the Canadian oil sands

### About this report

**Purpose.** In 2013, IHS Markit released a Strategic Report titled *Extracting Economic Value from the Canadian Oil Sands: Upgrading and refining in Alberta (or not).* This report explored the economic drivers behind the decision to invest in facilities that process bitumen. Since 2013, considerable change has occurred in global oil markets, but interest in the economics of processing bitumen in Canada, and Alberta in particular, remains high. This report provides a new look at our 2013 analysis, taking into account current market conditions.

**Context.** This is part of a series of reports from IHS Markit Canadian Oil Sands 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.

This report and past Canadian Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** This report updates the prior study released on 27 March 2013 that explored the economic drivers behind the decision to invest in processing bitumen or not. Leveraging the prior work methodology, IHS Markit conducted an update and review of the issues and market conditions associated with processing heavy oil in selected regions. IHS Markit has full editorial control over this report and is solely responsible for the report's contents.

This study analyzes whether capital costs to process heavy oil can be covered in selected geographies. The analysis does not consider the comparative economics of processing different crude grades, competition, energy security considerations, or additional commercial factors.

**Structure.** This report has four sections:

- Part 1: Introduction
- Part 2: Processing heavy oil
- Part 3: Methodology
- Part 4: Results

# A New Look

## Extracting economic value from the Canadian oil sands

**Kevin Birn,** Senior Director

**Karen Kuang,** Senior Research Analyst

**Patrick Smith,** Research Analyst

### Key implications

In 2008, there were 10 heavy crude oil processing facilities advancing in Alberta. Of the 10, 3 were completed, and 2 more are near completion. In 2013, IHS Markit analyzed the economics of processing heavy oil in Alberta against selected jurisdictions. Since then, much has changed in oil markets, yet the questions regarding investments in "value-added" bitumen processing have not.

- **Is this as good as it gets?** Lower oil prices and reduced investment have contributed to cost deflation in Alberta, while a pending shift in global marine fuel specification has the potential to improve the economics of processing heavy oil in Alberta relative to the 2013 study. Even so, incremental investments in heavy oil processing in Alberta remain challenged, and the potential economic improvements are limited and uncertain.

- **Incremental investments in new stand-alone upgrading projects in western Canada remain challenged.** Capital costs and narrow price margins between light and heavy crude continue to contest the economics behind upgrading in the IHS Markit outlook.

- **The most economic option for consuming heavy oil is to convert an existing facility.** Lower capital costs are the primary reason behind the relative attractiveness of conversions over new refinery projects. Although new conversion projects are able to recoup their capital costs, the rise of US light, tight oil has diminished interest in new conversion projects in North America.

- **Asian refining economics are the most attractive greenfield refinery investment option.** Lower capital costs and growing product demand in Asia, compared with North America, continue to advantage Asian refining economics. Although new refineries may be possible in Canada, they are not without risk, likely having to rely on offshore export markets. West coast facilities may be more attractive than landlocked Alberta facilities, owing to anticipated construction savings.

# Part 1: Introduction

Bitumen, the extra-heavy oil found in the oil sands, requires capital-intensive heavy oil conversion units to transform it into refined products such as gasoline or diesel. Bitumen is also too heavy and viscous for pipeline transport. As a result, oil sands producers historically faced two options to deliver their product to market. The first involves blending bitumen with lighter hydrocarbons to reduce its viscosity, allowing it to be moved via pipeline to refiners that have made specific investments in heavy oil processing capacity. The other option is to invest in heavy processing units near or at producing facilities that convert the extra-heavy oil into lighter crudes before shipping to markets. The resulting process is known as upgrading and produces a light synthetic crude oil (SCO) that competes with other light crudes in refineries that lack heavy processing capacity.

For many years, oil sands producers opted to invest in upgraders and market SCO. Prior to 2008, more than 10 projects were advancing, and over $100 billion was potentially committed to nearly 3 MMb/d of processing capacity in Alberta. At the time, upgrading was advantaged because SCO was able to obtain a significant price premium over the alternative: bitumen blends. Following the financial collapse in 2008 and then the rise in oil prices, construction costs appreciated in Alberta, while the rise of US light, tight oil reduced upgrading margins and interest in upgraders declined. Since 2008, four projects have been completed (Horizon Phase 1 and 2, Long Lake Phase 1, and Albian Sands Expansion Project), and two more (Sturgeon Refinery Phase 1 and Horizon Phase 3) are nearing completion in Alberta.

For Alberta and Canada in general, processing (upgrading and refining) has been viewed as a means to extract greater economic benefit from oil production. A common belief is that by either upgrading bitumen into SCO or producing refined products locally, upstream producers could expand their market and offer higher-value commodities. In the process, Canada would benefit from greater employment and revenue generation.

Relative to its population, Alberta already has considerable processing capacity. Alberta has about 12% of the national population, and its four refineries—not including its five upgraders—account for one-third of the refining capacity in Canada.[1] Since the Great Recession of 2008–09, the economics surrounding upgraders have been challenged, and interest in investing in additional processing capacity in Alberta has fallen but not ceased. Public interest remains high; and, in addition to Alberta-based proposals, several projects have been proposed further afield in Canada (see Table 1).

Table 1

**Proposed Canadian heavy oil processing projects outside of Alberta**

| Region | Processing | Capacity (b/d) |
|---|---|---|
| Terrace/Kitimat, British Columbia | Pacific Future Energy Refinery Project (announced) | 200,000 |
| Kitimat, British Columbia | Kitimat Clean Refinery (announced) | 400,000 |
| Pacific North Coast of British Columbia | Eagle Spirit Energy Upgrader (announced) | 1,000,000 |
| Sarnia, Ontario | Sarnia-Lambton Advanced Bitumen Energy Refinery (SABER) (announced) | 150,000 |

Source: Various sources and company publications © 2017 IHS Markit

## The case for a new look

In 2013, IHS Markit analyzed the prospects for processing oil sands bitumen into light SCO and refined products across selected jurisdictions. IHS Markit found that the most economic option to process heavy crude oil was to convert an existing refinery. Upgraders were particularly challenged, and greenfield refineries under specific conditions could work in North America but were not without risk.

Since the IHS Markit original 2013 analysis, the oil markets have changed considerably. US tight oil production continued its dramatic rise. In 2015, US production topped 8.8 MMb/d—2.3 MMb/d greater than in 2012. Abundance of US production helped tip the oil market into surplus late in 2014. In a matter of months, from late in 2014 to early 2015, global oil prices collapsed from an average of $100/bbl since 2011 to less than $50/bbl. Although Canadian oil sands production has continued to expand, investment is falling, and growth is expected to be more modest in the coming decade. With the ban on US exports removed in 2016 and prices expected to gradually recover, the United States is poised to become a major exporter of crude oil. Much has changed in a short period.

1. Alberta has four refineries with nearly 0.5 MMb/d of processing capacity and five upgraders with over 1.3 MMb/d of capacity. The Nexen (a wholly owned subsidiary of CNOOC Limited) Long Lake project includes an upgrader, but the project was not included in the analysis because of damage it incurred from an explosion in July 2016.

This report provides a fresh look at the economics of processing heavy crude oil from the oil sands in Alberta and other select regions.[2] The original report covered 2015–30, while this report covers 2021–36, reflecting the earliest that a large-scale project sanctioned in 2017 could be online.

This report has four sections:

- Part 1: Introduction
- Part 2: Processing heavy oil
- Part 3: Methodology
- Part 4: Results

Throughout this report, we refer to various crude oil terms. See the box "Primer: Canadian oil sands" for definitions.

## Part 2: Processing heavy oil

Similar to other crudes, crude oil from the oil sands must be converted into gasoline and diesel before it can be consumed. However, the raw oil sands product—bitumen—is more dense than most other crude oil, with a consistency similar to peanut butter. As a result, the density of bitumen must be reduced before it can be transported by pipeline. As shown in Figure 1, the transformation of bitumen into refined product can take place in either a two-step process (upgrading to a light, sweet crude called SCO in one location and refining into transportation fuels in another) or in a single step (refining the bitumen directly into transportation fuels). In either process, the refinery could be located in Alberta or thousands of miles away.

In the early years of oil sands development, upgrading bitumen into SCO was the most common strategy used by upstream operators. Limited access to refineries capable of processing extra-heavy oil and technical requirements related to the extraction process contributed to the historical dominance of the two-step process.[3] More recently, oil sands growth has been dominated by projects opting to market heavier bitumen blends. In 2012, the supply of heavy bitumen blends overtook SCO as the dominant form of oil sands supply output. Yet upgrading remains a significant share of

### Primer: Canadian oil sands

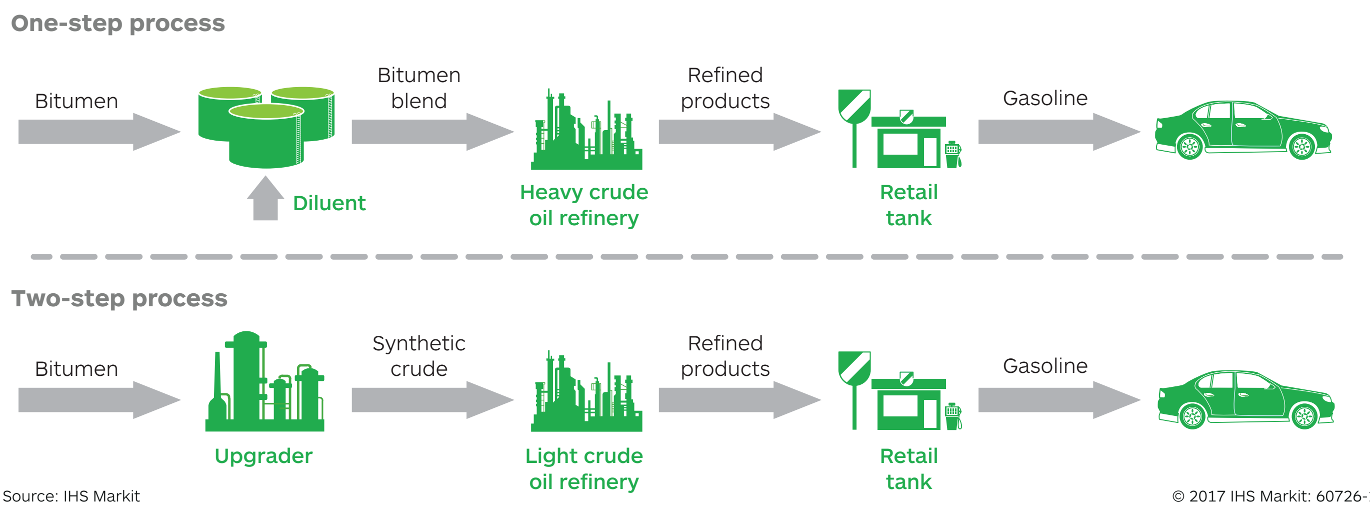
In its natural state, raw bitumen is solid at room temperature and cannot be transported by pipeline. For pipeline transport, bitumen must be either diluted with light oil into a bitumen blend or converted into a light crude oil called SCO.

- **Synthetic crude oil.** SCO is produced from bitumen via refinery conversion units called upgraders that turn heavy hydrocarbons into lighter, more valuable components from which gasoline and diesel are manufactured. SCO resembles light, sweet crude oil, with API gravity typically greater than 30 degrees (°).
- **Bitumen blend and dilbit.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons. A refinery may need modifications to process large amounts of bitumen blends because they result in more heavy oil products than most crude oils. Bitumen blends typically have a gravity of 22°API (similar to other heavy crude oils such as Mexican Maya). The most common bitumen blend involves diluting bitumen with a natural gas condensate (pentane plus material) to make diluted bitumen, or dilbit. A typical blend is about 72% bitumen and 28% condensate.

2. For more information and access to the legacy report, see www.ihsmarkit.com/oilsandsdialogue.

3. In the early years of oil sands development (when commercial production was primarily limited to surface mining operations), extraction methods required bitumen to be upgraded. However, today, new mining extraction techniques have been developed that enable producers to dilute mined bitumen and transport it to market without upgrading. Production by in situ extraction, a growing source of oil sands supply, also does not require upgrading prior to shipment to market.

**Bitumen upgrading and refining**




Source: IHS Markit

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output. In 2016, more than two-fifths of every barrel produced in the oil sands underwent some form of upgrading in western Canada.[4]

A lower crude oil price environment since 2014 has managed to reduce the pace of oil sands development, but growth is still anticipated. Owing primarily to the completion of projects under construction prior to the price collapse, production is expected to rise by more than 700,000 b/d, to more than 3.1 MMb/d, from 2016 to 2020. To meet global demand over the longer term, IHS Markit expects prices to rise gradually to incentivize new investments in upstream production. By 2026, oil sands production could top 3.6 MMb/d.[5] IHS Markit estimates that more than one-tenth of the anticipated growth between 2016 and 2026 will upgrade to some extent in Alberta. This value does not include additional western Canadian refining capacity from projects such as the Sturgeon Refinery.[6] This section will review the unique characteristics that influence the decision to invest in heavy oil processing capacity (in general and in Alberta).

## Economics of processing heavy oil

The decision between the one- or two-step processes involves a number of variables, such as energy input cost (e.g., natural gas), operating cost, capital cost, the value and availability of alternative input crudes, and the value of the resulting marketed product (whether it is upgraded SCO or refined product such as gasoline or diesel). Among these factors, capital costs and anticipated savings from processing lower-priced heavy crude oil as opposed to more expensive lighter crudes (light-heavy price differential) are the two most important variables affecting the economics of investing in heavy oil processing capacity.

**Capital costs.** Capital costs encompass all the up-front expense associated with bringing a project from concept to commercial use. New greenfield refineries and upgraders cost billions (and, in some cases, tens of billions) of dollars. These totals include the costs for construction, equipment, machinery, engineering, design, and labor. Many of these key input costs will track one another across global markets, such as steel. However, labor, which can be up to one-third or more of a project's total cost, is not always mobile and is a key reason why costs differ across regions.

**Light-heavy differential.** The difference in price between light crudes and heavy crudes—known as the "light-heavy differential"—is the other major factor influencing the decision to invest in heavy oil processing capacity. Once a heavy facility is built and operational, its profitability is based, in large part, on the price difference between the heavy crudes

4. Oil sands can include oil sands mining, thermal in situ extraction, and primary recovery. Depending on which categories of extraction are included, the share of upgraded oil sands can vary.

5. For more information, see the IHS Markit Energy Blog "Canada's oil sands to remain a growth story."

6. If the Sturgeon Refinery is included, one-sixth of anticipated growth will be processed in western Canada. Other anticipated refining demand changes are not considered in this estimate.

consumed and light products produced. Therefore, the wider the light-heavy price differential is, the greater the profit margin is and the quicker the initial capital invested can be repaid.

**Operating costs.** Operating costs are all of the day-to-day costs incurred to operate a facility. These include the variable costs for parts, maintenance, materials, labor, and energy to run the facility. Similar to capital costs, the higher the operating costs are, the more challenged the economics.

## Why it costs more in Alberta

In the past, the escalation of oil sands projects' capital costs earned Alberta a reputation for being a higher-cost jurisdiction. Indeed, capital cost escalation prior to the oil price collapse in 2014 was a global phenomenon brought on by higher oil prices that incentivized greater activity. However, cost inflation in Alberta was particularly acute. Labor costs were the primary reason, but other factors such as geography and climate also contributed to Alberta being a higher-cost jurisdiction.[7]

In the past, Alberta's labor demand, driven by oil sands developments and regional infrastructure projects, often exceeded local supply. Competition for skilled labor contributed to higher wages and at the same time attracted new, less experienced workers, reducing productivity. The result was an escalation in labor costs.

Alberta's climate also poses some challenges that can hamper productivity and add cost. Harsh winter conditions slow construction, and a large variance in temperature necessitates additional design requirements, such as greater insulation for the winter and cooling in the summer.[8]

For Alberta, being landlocked also increases on-site fabrication, thus exacerbating labor cost issues. Projects on or near tidewater can access large prefabricated modules (some up to the size of a football field) sourced from lower-cost jurisdictions. Because Alberta has no tidewater access, modules—and indeed all material and equipment—must be transported by truck, which materially reduces the size of each module and cost savings from off-site construction. This increases fabrication and thus labor demand.

### How capital costs have changed

After our 2013 report, costs in Alberta continued to appreciate before beginning to depreciate in 2015. Development of new processing capacity takes years, and the degree of today's cost savings could diminish as oil prices gradually recover and activity returns over the coming years. Although IHS Markit expects a period of more modest investment in the oil sands, and thus less domestic cost inflation pressure, many cost factors are global, and an uptick in US activity would be expected to affect costs in Alberta. Because of these factors, the capital cost estimates used in this analysis ended up being similar to those in our 2013 report. Alberta remained the highest-cost jurisdiction.

Our cost update made use of recent project announcements, the IHS Markit Upstream Capital Costs Index, the IHS Markit Downstream Capital Costs Index, and the IHS Markit Oil Sands Capital Costs Index to update capital cost assumptions.[9] Because costs are variable over time and can change between sanctioning and completion, a range was used in our analysis.

## Light-heavy differential expected to widen but stay narrower than historical levels

Prior to the 2008–09 financial crisis, global supplies of light, sweet crude were dwindling. This put upward pressure on the price of lighter crudes and helped to widen the price difference to heavier crudes. Since then, the situation has changed dramatically: the global light-heavy differential narrowed owing to the dramatic rise of light, sweet US tight oil supply and increased demand for heavy crude from the completion of several conversion projects (see Figure 2).[10]

7. For more information on oil sands' history of cost escalation, see the IHS Markit Strategic Report *Oil Sands Cost and Competitiveness.*

8. Temperatures in Alberta can range from over 80° Fahrenheit (F) (30° Celsius [C]) to −40°F (−40°C).

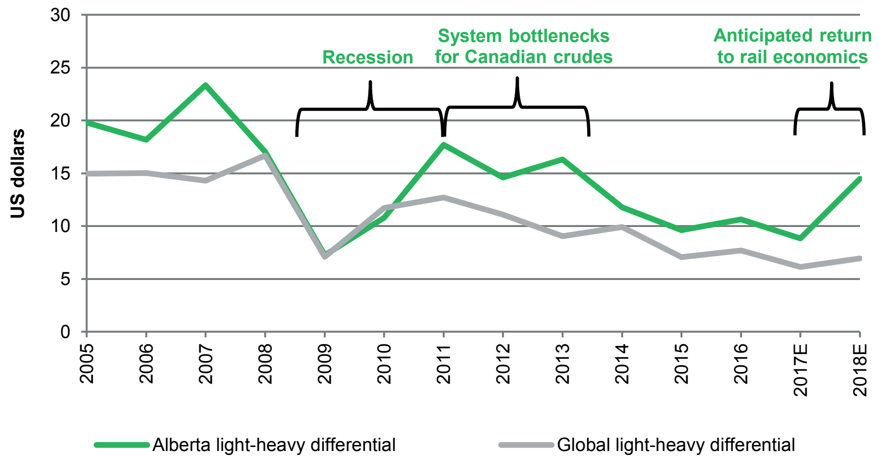
9. See the IHS Markit Indexes, https://www.ihs.com/info/cera/ihsindexes.

10. Tight oil is a light, sweet crude produced from shale and tight oil formations through a process called hydraulic fracturing. From 2009 to 2016, US production increased by 2.8 MMb/d, from 5.3 MMb/d in 2009—a pace of growth unprecedented in the history of crude oil markets. Over the same period, about 300,000 b/d of heavy (vacuum residue) conversion capacity was added in North America.

Since 2014, lower prices have reduced investment in global oil production. Reduced upstream investment is expected to lead to a gradual tightening of the availability of light and heavy oil alike, with the latter helped along by the acceleration of already declining heavy oil supply from Mexico and by instability in some key heavy oil–producing regions. Reduced heavy availability, coupled with OPEC production restraints that have largely come from heavier production, has helped to narrow the light-heavy differential we have seen in 2017.

Figure 2

**Global and Canadian light-heavy price differentials**




Notes: Light-heavy in Edmonton is Western Canadian Select (WCS) less Mixed Sweet Blend. Global light-heavy is based on Mexican Maya less Louisiana Light Sweet (LLS).
Source: IHS Markit

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Looking to the future, OPEC constraints will not remain in perpetuity, and the price spread is expected to gradually widen toward historical trends as oil prices recover. However, because of an anticipated change in marine fuel quality specifications, an increase in the light-heavy differential is expected. Starting in 2020, International Maritime Organization (IMO) members have agreed to reduce the allowable levels of marine sulfur dioxide ($SO_2$) air emissions from the global shipping fleet. Although there are other compliance pathways for marine vessels to meet this requirement, such as installation of shipboard scrubbers or use of LNG as a fuel, the primary means to achieving this objective in the immediate term will likely be a reduction in sulfur content in marine transport fuels. Heavier crudes, including from the oil sands, typically contain higher levels of sulfur. Increased investment will be required to remove additional sulfur or address $SO_2$ emissions from marine fuels and is expected to temporarily lower (widen) the value of heavy, sour (higher-sulfur) crude oil, such as from the oil sands.[11] In turn, the greater price difference will incentivize investments in infrastructure to address the sulfur content and allow the global light-heavy differential to gradually narrow to long-run trends. Key to the degree of the IMO impact on light-heavy differentials will be the level of compliance. Should compliance of the marine fleet be lacking, the impact on differentials could be less pronounced but persist over a longer period. Should the degree of compliance be greater at the onset, the impact on differentials could be larger but would likely span a shorter period. In either instance, a wider light-heavy differential should emerge around 2020–22 and narrow thereafter toward a long-run global average. This outlook differs from that in our 2013 report, which did not include the new air emission regulation. Compared with our prior report, the global light-heavy differential is, on average, about 10% wider over the forthcoming decade, with the majority of the IMO's impact playing out in the early 2020s.[12]

All things being equal, the Canadian light-heavy differential tracks the global trend. However, in the past, system bottlenecks from insufficient pipeline takeaway capacity and/or limited refining markets for Canadian heavy crudes contributed to a widening of the differential. For example, on average in 2013, when some of the worst bottlenecks occurred, the difference in price between light and heavy crudes was about $6/bbl wider than the global average.[13] Meanwhile, the global light-heavy differential remained narrower than the historical differential, and the market distortion lowered the price of crude oil in western Canada (and producer and government revenues alike).

11. For more information, see "Sulphur oxides ($SO_x$) – Regulation 14," IMO, http://www.imo.org/en/OurWork/environment/pollutionprevention/airpollution/pages/sulphur-oxides-(sox)-%E2%80%93-regulation-14.aspx, retrieved 20 August 2017.

12. In our previous outlook, differentials were expected to widen gradually from 2020 to 2030. In this study, however, the differentials widen at the onset of the implementation of new air pollution controls and then narrow toward the long-run average.

13. This compares the global light-heavy price differential to Alberta's. Comparative global and Alberta heavy prices were much further apart. In 2014, WCS, a western Canadian heavy crude oil benchmark, was $24/bbl wider on average than Mexican Maya, a globally traded heavy crude benchmark.

Since the oil price collapse, despite continued oil sands production growth, western Canadian crude oil has managed to clear the market primarily via pipeline.[14] This has occurred as conventional production has fallen as a result of reduced investment, freeing up some capacity on existing takeaway pipelines, but also as a result of midstream companies finding ways to optimize their existing pipelines to increase throughput.[15] This has caused the light-heavy price spread to close in on the global average.

In the short term, continued completion and ramp-ups of new oil sands projects (sanctioned prior to the price collapse) will continue to put pressure on a constrained pipeline system. Moreover, the ability of pipeline operators to increase throughput is believed to be nearing its limit, and in the absence of new pipelines, supply will eventually overtake available pipeline capacity, and increased movements of crude by rail should be expected.[16] When this occurs, the price of heavy oil in western Canada is expected to weaken to reflect the higher cost of rail transport. This will widen the price difference between light and heavy crude in western Canada. Even with the onset of new pipeline development, the widening should hit a peak in about 2020–22 with the implementation of the new IMO marine fuel specifications. As investments are made to address additional volumes of sulfur, the light-heavy differential should follow global trends and narrow for the remainder of the outlook. In the absence of new pipelines in 2019–20, the differentials will remain wider, exacerbating the impact of the IMO on western Canadian light-heavy differentials.

**All paths to market require pipelines**

Investment in heavy oil processing in western Canada—or not—does not change the need for new pipelines. For upgraders, SCO supply is already greater than regional demand, reinforcing the need for new markets (and pipelines). The same is true for refining. On an average basis, Alberta produces more gasoline and diesel than local markets can consume. The surplus is typically sold to British Columbia and, to a lesser extent, Saskatchewan and Manitoba. Currently, major pipelines such as Trans Mountain, Alberta Clipper Expansion, and Keystone XL continue to advance and are included in our analysis. Wider price differences in Alberta that result from crude by rail are unlikely to encourage new investment in upgrading and refining, as incremental pipeline takeaway capacity would still be required for the resulting refined products. The reduced value of heavy crude oil in western Canada, at a time when prices are already low, could further dampen the incentive to invest in upstream production.

## Part 3: Methodology

This IHS Markit report explores the economic case for investing in heavy oil processing capacity in selected regions in North America and Asia. Table 2 shows the different cases explored in our analysis that have or could gain increased access to western Canadian heavy supply. For consistency, these are the same cases explored in our previous report.

What follows is a brief description of our methodology.

### Three options for processing heavy oil

As shown in Table 2, this report explores three options for processing heavy oil: upgraders, greenfield heavy oil refineries, and/or conversion of existing facilities to process heavy oil.

**Upgraders.** Upgraders are facilities designed to convert extra-heavy crude

Table 2

**Project types and markets included in IHS Markit analysis**

| Project types | Markets |
|---|---|
| Greenfield upgrader | British Columbia (West Coast) |
| | Alberta (Edmonton) |
| Refinery conversion | Alberta (Edmonton) |
| | Quebec (Montreal) |
| | US Midwest (Chicago) |
| | US Gulf Coast (Houston) |
| | Asia (South China) |
| Greenfield refinery | British Columbia (West Coast) |
| | Asia (South China) |
| | Alberta (Edmonton) |

Source: IHS Markit © 2017 IHS Markit

14. Some volumes of crude by rail have persisted. In 2014, 2015, and 2016, movements of Canadian crude by rail averaged 181,000 b/d, 140,000 b/d, and 90,000 b/d for the first nine months, respectively.

15. Examples of pipeline optimization include Enbridge Pipeline's Canadian Mainline system's ability to fully utilize its existing cross-border permit capacity on Line 3 to increase movement by an estimated 350,000 b/d since 2014.

16. For more information, see the IHS Markit Strategic Report *Pipelines, Prices, and Promises: The story of western Canadian market access.*

found in the oil sands into lighter SCO. An upgrader generates profit on the price difference between the input crude—bitumen—and the price they are able to obtain for their output crude—SCO. Therefore, the greater the gap in price between bitumen and SCO, the greater the incentive to upgrade heavy crude. Because SCO is a lighter crude and requires a less sophisticated refinery and less energy to refine, it commands a higher price than the alternative bitumen blends. However, SCO competes with other light crudes for light refining capacity, a particular concern given the surge of light, tight oil production in the United States.

**Greenfield refinery.** Refineries convert crude oil into refined products, such as gasoline, diesel, and jet fuel. The exact yield of different products created by a refinery depends on the input crude and the configuration of the facility. In general, a refinery makes money on the price difference between the input crude and the sale of the individual refined products produced—the margin. The investment prospects of refineries become more attractive the greater the margin. For our analysis, we assumed any new facility would prioritize diesel output over gasoline, which was expected to command a higher price because of growing commercial demand.[17]

**Refinery conversions.** The third option for consuming heavier crude oil is to convert an existing refinery. This involves adding heavy crude conversion units to an existing refinery originally designed for lighter crude oils. The economics are similar to a greenfield refinery, but this option is less capital intensive because it generally utilizes the existing refinery infrastructure and portions of the equipment. Of course the feasibility is dependent on the availability of a facility as a candidate for conversion. For conversions, we assumed they would continue to market a yield of products more consistent with historical facilities, producing more gasoline than diesel.

There is interest in developing an alternative to the one- and two-step options for delivering bitumen to market from Alberta. This option has been called “partial processing” or “partial upgrading.” There are numerous processes being advanced. In general, they seek to either remove impurities, such as sulfur, or extract the heaviest components in bitumen, such as asphaltenes. In doing so, the viscosity is reduced, eliminating or dramatically reducing the need for diluent. Often, a modest uptick in price over dilbit can be obtained. Key to these alternatives’ success will be whether they can be done at a lower cost than the diluent blending option. Given the variety of different partial processes being advanced and the lack of commercial scale projects, IHS Markit did not model these potential alternative processes. For more information on partial processing, see the box “A partial process to market.”

## A partial process to market

Canadian oil sands producers are searching for another option to market bitumen—one that could achieve some of the benefits of upgrading while avoiding the significant capital outlay. There are cost challenges associated with both the one- and two-step options for delivering bitumen products to market.

For producers that chose a one-step process—where bitumen is marketed to refiners—bitumen must be diluted with lighter hydrocarbons to meet pipeline specifications. Diluent comes at a cost for producers. It must be purchased and then transported to market along with the bitumen, increasing transportation costs. For example, to move 1 bbl of bitumen, a producer must acquire about 0.40 bbl of diluent and then pay the pipeline toll for the resulting 1.40 bbl of dilbit per barrel of bitumen produced.* To be certain, dilbit receives a premium over the price of bitumen—for the share of higher-value diluent—but the uptick in the price is less than the cost of acquiring the diluent in Alberta and then transporting the resulting blend to market (i.e., the diluent portion being valued by refiners for less than its purchase cost). Moreover, should pipelines remain constrained, bitumen with little or no diluent would require less pipeline capacity than a similar volume of bitumen that requires blending.

Partial processing promises to move bitumen up the value chain, past dilbit, and eliminate or dramatically reduce the need for diluent while falling short of producing and incurring the cost to produce a light SCO. Several technologies are being advanced, and a few pilots are in operation or development. However, none have been proven on a large commercial scale. For commercial viability, partial process facilities must be able to achieve better economics than blending bitumen.

*This assumes a typical dilbit blend rate of 70% bitumen and 30% diluent.

17. Global demand growth for diesel is anticipated to continue to exceed that of gasoline. Therefore, on average and all things being equal, it is expected to obtain a premium over gasoline.

## Summary assumptions

To capture the uncertainty, a range of inputs were included in our cases and models. The results are best interpreted as a range rather than as high or low cases. Considerable data and forecasting were required for modeling purposes, such as long-run refined product prices, light and heavy crude input prices, transportation costs/tariffs, capital costs, and operating cost assumptions. Of all of these variables, the most influential were capital costs and the light-heavy price spread (including refined products). These are discussed below, followed by Table 3, which summarizes the key assumptions.

Differentials were captured by taking the value of the most likely representative light crude in each market and comparing it against the anticipated value of dilbit transported to each market by pipeline (or marine vessels in some instances). Where distinct transportation routes may exist (such as to Asia or the US Gulf Coast), alternative transportation routes and costs were modeled, as shown in Table 3. For facilities based in Alberta, it was assumed that they would be able to process undiluted, raw bitumen. It was also assumed that it may be conceivable that a facility located in British Columbia would be able to access raw bitumen by rail or through the construction of a diluent recycle pipeline.

Table 3

**Key assumptions for economic calculations**

| Project type | Location | Capital cost (US dollars per 100,000 b/d of capacity) | Operating cost (US$/bbl) | Light-heavy differential (average from 2016 to 2030, US$/bbl)[1] | Light crude input | Heavy crude input | Refined product yields (volume ratio of crude feed: gasoline: diesel)[2] |
|---|---|---|---|---|---|---|---|
| Greenfield refineries | Alberta (Edmonton)[3] | 6.9–8.6 billion | 8.00–10.00 | 21.61–33.38[4] | Edmonton Par (in Edmonton) | Dilbit to bitumen (in Edmonton) | 2:1:1 |
| | West Coast[3] | 4.8–6.0 billion | 7.00–9.00 | 16.92–27.41[4] | Arabian Light (on West Coast)[5] | Dilbit to bitumen (on West Coast) | 2:1:1 |
| | Asia (South China) | 2.9–3.6 billion | 4.50–6.50 | 14.91–16.12 | Arabian Light (in South China) | Dilbit (in South China) | 2:1:1 |
| Refinery conversions | Alberta (Edmonton) | 2.7–3.9 billion | 6.00–8.00 | 22.00 | Edmonton Par (in Edmonton) | Dilbit (in Edmonton) | 3:2:1 |
| | Quebec (Montreal) | 1.9–2.8 billion | 5.00–7.00 | 22.60 | Brent (in Montreal) | Dilbit (in Montreal) | 3:2:1 |
| | US Midwest | 1.7–2.6 billion | 5.00–7.00 | 20.28 | WTI (Chicago) | Dilbit (in Chicago) | 3:2:1 |
| | US Gulf Coast[6] | 0–1.5 billion[7] | 4.50–6.50 | 12.50–16.59 | Eagleford to LLS (St. James) | Dilbit (on US Gulf Coast) | 3:2:1 |
| | Asia (South China) | 1.2–2.0 billion | 4.00–6.00 | 14.91–16.12 | Arabian Light (in South China) | Dilbit (in South China) | 3:2:1 |
| Upgraders | Alberta (Edmonton) | 5.8–7.0 billion | 8.00–10.00 | 33.38 | SCO (in Edmonton) | Bitumen (in Edmonton) | N/A |
| | West Coast | 4.1–4.9 billion | 7.00–9.00 | 27.41 | SCO (on West Coast) | Bitumen (recycled diluent on West Coast)[8] | N/A |

1. The light-heavy differential is based on the average price from 2021 to 2035 of the most prevalent anticipated light crude oil in each market and of dilbit or bitumen (depending on the project) delivered to each market. The price range was chosen to start in 2021 because it was deemed the earliest that a facility could be operational given a sanctioning decision today. Alberta-based oil sands crude prices were adjusted to reflect expected pipeline and tanker tolls. Toll assumptions from Edmonton to each market are $4 to the West Coast, $7–8 to Asia, $5 to the US Midwest (Chicago area), $9–14 to the US Gulf Coast, and $5 to Montreal. There was potential for multiple routes and tolls to Asia and the US Gulf Coast; therefore, a high and low transportation assumption resulted in a range for the light-heavy differential. There were two potential routes to the US Gulf Coast—one potentially via Energy East (which was active at the time this analysis was completed) down the coast by tanker and another over land by pipeline, which resulted in a range for light-heavy differential.
2. It was assumed that a new greenfield refinery would be designed to maximize diesel output over gasoline: for 2 bbl consumed, equal parts of gasoline and diesel would be produced (2:1:1). For refinery conversions, the refined product yields were assumed to continue targeting gasoline: two parts gasoline to diesel (3:2:1).
3. IHS Markit assumed both the West Coast– and Alberta-based greenfield refineries would be export oriented, obtaining the highest-value product from either California or Asia to potential markets. Other refined by-products such as NGLs or petrochemical feedstock were assumed to be sold into the local market.
4. The wide differential is based on consuming bitumen; the narrow differential is based on consuming dilbit.
5. Arabian Light was chosen as representative of light, sweet crude oil on the West Coast to reflect global crude access and orientation of facility as an export facility targeting Asia.
6. For the US Gulf Coast, there are two potential scenarios—one being onshore (Eagleford and dilbit via pipe) and another at tidewater (LLS and dilbit by tanker via Energy East).
7. Approximately 2.4 MMb/d of capacity on the US Gulf Coast is already suited to consuming heavy oil sands crude oil, and no capital investment may be required. A capital cost of $14,000 per flowing barrel was assumed for the US Gulf Coast conversions. The zero–capital cost case—although very likely—was not explicitly modeled.
8. For West Coast refining and upgrading of raw bitumen, we also assume diluent would be recycled, albeit at an additional pipeline toll.

Source: IHS Markit

- **Refinery configuration.** It was assumed that greenfield refineries would be designed to maximize diesel output—a higher-value refined product. Specifically, it was assumed that a new refinery would be able to produce equal parts diesel and gasoline (known as 2:1:1 yield).[18] For refinery conversion projects, it was assumed that they would continue to produce more in line with historical output and would produce roughly double the volume of gasoline to diesel.[19]

## Part 4: Results

To compare the economics for processing bitumen in Alberta to that of other locations, we compared the internal rate of return (IRR) across all project types and markets (see Figure 3).[20]

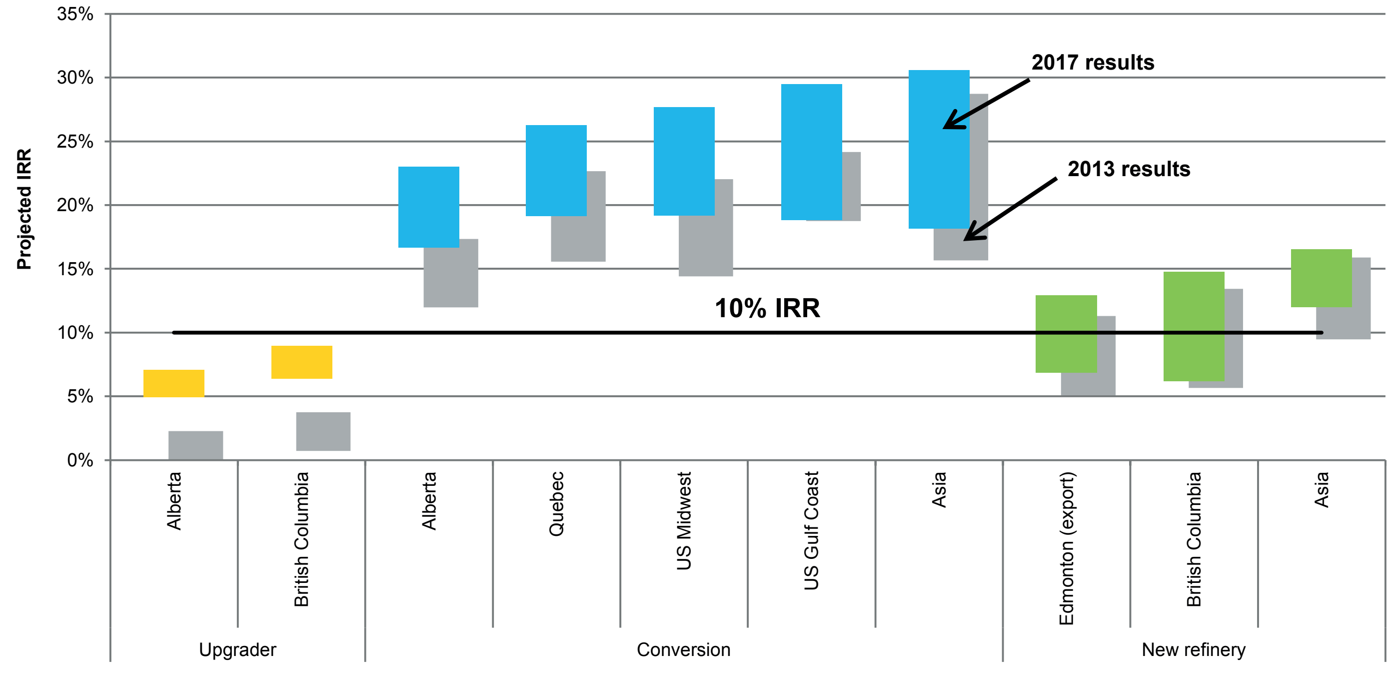
These results are best interpreted as a range of equally probable outcomes. Our study does not explore the comparative economics of alternative refinery configurations and/or grades of crude oil (i.e., light, medium, heavy, etc.). All cases are generic and are not configured or meant to replicate any specific facility (existing or proposed).

### Summary

As shown in Figure 3, since our 2013 analysis the economics of investing in heavy crude oil processing capacity have improved. This is principally the result of flat to slightly lower capital costs and a wider global light-heavy price difference in the near term resulting from proposed international marine air pollution rules going into effect in 2020. Of the heavy oil processing options explored, refinery conversions remain the most attractive. The economics of greenfield refineries were largely consistent with our prior study. Although the return is still below that of Asia, a new refinery could work in Alberta or British Columbia given the right circumstances, but not without some risk. Upgraders improved but still fell short of being able to achieve a 10% IRR threshold. More detailed discussions of each case follow.

Figure 3

**IRR for oil sands upgrading and refining projects (2017 results compared with 2013)**




Source: IHS Markit

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18. For every 2 bbl of crude oil, 1 bbl of diesel and 1 bbl of gasoline are produced. This is known as 2:1:1.

19. Processing 3 bbl of crude oil would result in roughly 2 bbl of gasoline and 1 bbl of diesel.

20. Although we have highlighted a 10% IRR rate as an indicative threshold in Figure 3, this is not necessarily the cutoff for all projects. In reality, the actual IRR that would be required to justify an investment decision may be unique for each company and project. Actual thresholds could be higher or lower than our chosen threshold value.

**Refinery conversions**

Refinery conversions remain the most attractive investment option in heavy oil processing capacity. Conversion projects have the lowest capital costs, compared with upgrading or greenfield refineries, while benefiting from a greater uplift from the sale of refined products.

The US Gulf Coast and Asian conversion projects were the most attractive and had comparable economics, with both markets benefiting from lower capital costs—Asia because it is cheaper to build there and the US Gulf Coast because it has a preexisting fleet of heavy crude oil processing capacity that would require comparatively less new investment to process greater quantities of Canadian heavy. The US Gulf Coast results spanned a wider range than in our previous report. This is a result of this study taking into consideration the potential for alternative transportation routes and refinery centers in the US Gulf Coast: on tidewater using waterborne crude oil or inland using overland pipelines.

Quebec continued to be the most attractive Canadian conversion project. Despite lower feedstock prices and stronger product prices in Alberta, Quebec benefited from lower anticipated capital costs.

Key for any conversion project to take place—economic or not—is an existing facility to convert. This may be a particular issue for facilities in western Canada, where most are already vertically integrated with upstream supply. The relative economic case for investing in conversion projects versus continuing to process lighter crude oil is not considered in the IHS Markit approach.

**Greenfield refineries**

In our study, Asia remains the most attractive region in which to build a new refinery. Asia benefits from lower labor (and thus, capital) costs than other cases. Assuming oil sands are able to access Asia in meaningful quantities, investment in new heavy oil refineries can be economic. Asia provides a large and growing product demand market where many new refineries will be built.

Refinery cases for both Alberta and British Columbia improved relative to our previous analysis, owing to wider differentials in our outlook.

Investment in new refineries in Alberta and British Columbia are not without risk. Alberta already produces more refined product than is required and must export it. Additional volumes of refined product are already expected in Alberta in 2017 with the completion of North West Redwater Sturgeon Refinery. Incremental refined products—principally diesel—were expected to help meet growing industrial demand in Alberta from the oil sands. However, a lower price environment has reduced expectations of oil sands activity and refined product demand growth alike. Overall refined product demand in North America is in decline. By 2030, demand could be about 6% lower than in 2016. This means that new investments in refining capacity, whether they are made in Alberta or British Columbia, could either have to displace incumbents or, more likely, be exported offshore. No reduction in refined product prices was made to account for the added supply into the market.[21] Although Alberta enjoys lower feedstock costs than British Columbia, a landlocked, export-oriented facility in Alberta would likely face greater logistical complexity and costs compared with a facility on tidewater. This moderately disadvantaged Alberta in our analysis. Even for a facility on tidewater, finding a party willing to commit to a mutually agreeable long-term purchase agreement—likely a necessity for obtaining financing for a new export-oriented refining project—may be a stumbling block.

**Upgraders**

The economic case for upgraders improved from our previous analysis, but they were still not able to achieve 10% IRR. Upgraders benefited from anticipated wider light-heavy differentials owing to new air pollution regulations for the marine shipping fleet, coupled with the advancement of our study period forward to 2021–36 (which, in general, has wider differentials than the 2013 analysis). The British Columbia facility benefited from modestly lower operating and capital costs than Alberta.

21. For incremental production from new facilities, some supplies were assumed to be exported.

## Concluding remarks

Despite the enhanced prospects for investment in heavy oil processing capacity, the risks continue to weigh heavily on future investments. The anticipated slow decline in refined product demand in North America is expected to make the market increasingly competitive and export reliant. US tight oil, which has surprised and unsettled oil markets with both the scale and speed of production growth, has transformed the oil market and reduced the incentive to invest in heavy oil processing in North America. As the US tight oil industry emerges from lower prices, it has the potential to further influence the economics of investing in heavy oil processing capacity, although tight oil can now be exported from the United States and is doing so in increasing volumes. Marine shipping fleet air pollution rules planned for 2020 are expected to widen the price difference between light, sweet and heavy, sour crudes, increasing the incentive to process heavy crude for a period of time. Should the IMO impact be less pronounced on light-heavy differentials than IHS Markit anticipates or should the timing of a new heavy oil processing project be delayed and miss the most opportune period of anticipated wide differentials, the economics of the facilities modeled would decline. In Alberta, all of these factors are compounded by uncertainty over the timing and direction of future pipeline capacity.

## The IHS Markit team

**Kevin Birn,** Senior Director, IHS Markit, is part of the North American Crude Oil Markets team and leads the IHS Markit Oil Sands Dialogue. His expertise includes energy and climate policy, project economics, transportation logistics, and oil market fundamentals. His recent research includes analysis of the greenhouse gas intensity of oil sands, economic benefits of oil sands development, upgrading economics, oil sands competitiveness, and implications of advancing climate policy. To date, Mr. Birn has authored or coauthored 30 reports associated with development of the Canadian oil sands. Prior to joining IHS Markit, Mr. Birn worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources for the US Secretary of Energy*. Mr. Birn holds a BComm and an MA from the University of Alberta.

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# KEYSTONE XL PIPELINE:
# NO MATERIAL IMPACT ON US GHG EMISSIONS

*by Jackie Forrest and Aaron Brady*

**DATE**
5 August 2013

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## KEY INSIGHTS

In the recent debate surrounding the pending Keystone XL pipeline decision, new questions have been raised about the pipeline's potential impact on greenhouse gas (GHG) emissions. President Barack Obama has indicated that the relative emissions related to increased Canadian oil sands processing in US markets (resulting from the Keystone XL project) are a key criteria for the US Administration's decision. The conclusion of IHS CERA's analysis is that incremental GHG emissions from the pipeline would not be substantial.

- **The Keystone XL decision is also a market share decision between Canada and other imported heavy oil supplies, particularly those from Venezuela.** With or without oil sands supply to the US Gulf Coast (USGC), refiners there would continue to process heavy crude oils, since they are configured to run these grades. The most likely alternative USGC heavy oil supply is Venezuelan crude which is in the same GHG emissions range as oil sands. Consequently, if oil sands were not consumed in the Gulf Coast, there would be little to no change in the overall GHG intensity of the US crude slate.
- **Even if the Keystone XL pipeline does not move forward, we do not expect a material change to oil sands production growth.** Therefore the Keystone decision itself will not have any impact on GHG emissions. Without Keystone, alternatives will be developed including other pipeline projects and crude delivery by rail. Not including Keystone XL, the volume of proposed pipeline capacity exiting western Canada currently totals 3 million barrels per day (mbd). Eighty percent of this proposed capacity connects Alberta with Canada's west and east coasts, and obviously would not involve any US government approval. Even if new pipelines lag oil sands growth, rail will fill the gap, as it is doing today. With more investment, rail economics could approach those of pipeline.

## KEYSTONE XL PIPELINE: NO MATERIAL IMPACT ON US GHG EMISSIONS

In the recent debate surrounding the pending Keystone XL pipeline decision, new questions have been raised about the potential impact of the pipeline on

US greenhouse gas (GHG) emissions. In March of this year, the US State Department's Draft Supplemental Environmental Impact Statement (DSEIS) for Keystone XL concluded the project would have minimal effect on GHG emissions.[1] The State Department's logic was that in the absence of the Keystone XL project, oil sands production would still be moved to market either by alternative pipelines or rail.

However, the debate surrounding the pipeline's impact on US GHG emissions assumed a higher profile with President Barack Obama's June 25 climate address. In the speech, the president pledged not to approve the Keystone XL if the project would "significantly exacerbate the problem of carbon pollution." Following Obama's speech, the Canadian government was quick to point out that the pipe would not add to GHG emissions. Joe Oliver, Canada's minister of natural resources, said, "That's what the US State Department itself had concluded, in a 3,500 page report," adding, "This pipeline has been the most studied pipeline in the history of the world."[2]

The purpose of this Insight is to bring clarity to the question of Keystone XL and its potential GHG implications. IHS CERA's assessment agrees with the US State Department—Keystone XL will not be material to GHG emissions.[3]

## Pipeline opponents disagree with State Department

Pipeline opponents argue that by opening up additional US markets for Canadian oil sands, the Keystone XL project would lead to significant incremental US GHG emissions. Their primary dispute with the State Department's analysis centers on the economics of moving oil sands by rail, which is assumed to be the alternative method of transportation if Keystone XL or other pipelines are not constructed. They assert that rail costs are prohibitively high and that in a scenario in which pipelines are not constructed, oil sands growth (and consequently GHG emissions) will stall for lack of market access.

Critics cite the steep crude oil price discounts for Canadian producers in the past year as further evidence that rail is not economic. On average in 2012, the price of heavy oils sands was $27 per barrel lower than a comparable barrel on the US Gulf Coast (USGC), and for short periods the difference was more than $40 per barrel.[4]

However, these deep discounts were not the result of rail costs but rather due to a severe supply and demand imbalance: constraints in the pipeline and refining systems limited flows, resulting in a prolonged period of surplus supply. In fact, growing rail capacity from western Canada has helped to moderate the price discounts faced by Canadian producers by relieving this oversupply. By the end of the first quarter 2013, approximately 150,000 barrels per day (bd) of crude was leaving western Canada by rail (compared with negligible amounts at the start of 2012). Based

1. "[A]pproval or denial of the proposed Project is unlikely to have a substantial impact on the rate of development in the oil sands…. [if the project is not built] The incremental indirect life-cycle emissions associated with those decreases in oil sands production are estimated to be in the range of 0.07 to 0.83 million metric tons $CO_2$ equivalent ($MMTCO_2e$) annually," US Department of State, Draft Supplemental Environmental Impact Statement for Keystone XL, March 2013, page ES-15.
2. Source: National Post, June 25, 2012, Retrieved July 31, 2013.
3. IHS analysis is based on the ongoing IHS CERA Oil Sands Dialogue research. Since 2009, the IHS CERA Oil Sands Dialogue has brought together policymakers, industry representatives, academia, nongovernmental organizations, environmental organizations, and other related stakeholders to advance the conversation surrounding Canadian oil sands development. The objective is to enhance understanding of critical factors and questions surrounding industry issues and foster a fact-based discussion through workshops and published reports. For more information or to access past reports, please go to www.ihs.com\oilsandsdialogue.
4. Compares the price of Western Canadian Select at Hardisty, Alberta, with Mexican Maya pricing on the USGC. Maya pricing is the benchmark for heavy crude prices on the USGC, and Venezuelan heavy oils would trade at a similar price.

on continuing oil sands supply growth and the lack of new pipeline capacity through the next few years, we expect rail movements to increase to about 360,000 bd by the end of 2014.

Even considering new capacity from rail, the balance between western Canadian supply and export capacity remains tight. Future price volatility is to be expected. However, in some periods such as the past three months—with the help of new capacity from rail—the system has been relatively balanced, and a barrel of heavy oil sands crude priced on average $17 per barrel lower than the value of similar quality heavy oil traded on the USGC.[1] This indicates that oil sands can grow using rail; it is already happening.

## US Gulf Coast heavy oil: Market share issue between Canada and Venezuela

The US Gulf Coast has historically received modest volumes of heavy Canadian oil through a relatively small pipeline connection and rail (combined pipeline and rail have averaged about 130,000 bd in the past few years). However, this year we expect volumes could double from increased rail movements. If constructed, the Keystone XL pipeline would allow about 730,000 bd more of heavy crude to transit from the oil sands to the USGC, increasing the market for Canadian producers.[2]

Currently, the US Midwest is the key consuming region for oil sands products, but it is quickly reaching the saturation point, based on limited refining capacity able to accommodate heavy oil.

By contrast, the Gulf Coast region has a strong appetite for heavy crude—requiring 2.4 million barrels per day (mbd) in 2012. Its refineries are generally configured to optimally process this type of crude given the large scale of the coking capacity already in place. Therefore, with or without oil sands supply to the Gulf Coast, refiners there will continue to process heavy crude oils. (The USGC is the center of gravity for US refining with about half of the nation's total refining capacity).

Today, the majority of heavy supply on the USGC comes from Venezuela (0.8 mbd), followed by Mexico (0.7 mbd); the rest is from smaller suppliers including Colombia and Brazil. If Gulf refiners cannot access Canadian heavy oil, the most likely alternative is Venezuelan supply, which is projected to grow based on ongoing investments (including the Orinoco). Although Mexico has historically been a large supplier of heavy oil, its production has been dropping steadily (declining production has reduced exports; compared with seven years ago, heavy oil shipments to the United States have been cut in half). Therefore, the decision on Keystone XL may ultimately boil down to a determination of oil market share between Canada and Venezuela. Venezuelan heavy oil—and Venezuela—will be the number one beneficiary of a negative decision on Keystone.

The GHG emissions from Venezuelan supply are in the same GHG intensity range as oil sands (see Table 1). Thus, in a scenario in which incremental oil sands production did not reach the US Gulf market, there would be little to no change in the overall GHG intensity of the US crude slate.

1. Compares the average price of Western Canadian Select at Hardisty with Mexican Maya pricing on the USGC for May, June, and July 2013.
2. Total capacity for the Keystone XL pipeline is 830,000 bd. However, 100,000 bd of this capacity will be filled by the Bakken Marketlink project, leaving 730,000 bd of capacity remaining to transport oil sands crudes.

**Table 1**

**Life-cycle GHG emissions of oil sands and Venezuelan crudes compared***

| | Well-to-wheels GHG emissions** ($kgCO_2e$ per barrel) | Percent difference from average barrel refined in the United States (2005) |
|---|---|---|
| Venezuelan supply: Petrozuata (high) and Bachaquero (low)*** | 507–585 | 4–20% |
| Canadian oil sands heavy oil supply: SAGD SCO (high) and dilbit produced by mining (low) | 506–598 | 4–23% |

Source: IHS CERA.
Note: $kgCO_2e$ = kilograms of carbon dioxide equivalent; CSS = cyclic steam stimulation.
*See Table 2, page 23 IHS CERA Special Report *Oil Sands Greenhouse Gasses, and US Oil Supply: Getting the Numbers Right – 2012 Update*, November 2012. Reported values all assume a wide boundary for measuring GHG emissions and are consistent with the 2005 average crude baseline used in the current DSEIS. Wide boundary includes all emissions beyond the facility site including those from producing natural gas used at the oil production facilities and from electricity generated offsite.
**Well-to-wheels GHG emissions include all emissions associated with crude oil production and use, including extracting, refining, transporting, and ultimately consuming the fuel in a vehicle. Depending on the crude oil, 70–80% of the well-to-wheels emissions occur when gasoline is combusted in a vehicle. The absolute GHG emissions resulting from engine combustion of gasoline or diesel are independent of the type of crude used to refine the fuel.
***In addition to these to crudes, IHS CERA also has an estimate for Zuta Sweet crude from Venezuela, which is within this range at 547 $kgCO_2e$ per barrel, or 15% higher than the average barrel refined in the United States (2005). Although there are other heavy oil imports from Venezuela, there are no GHG intensity estimates for them. Generating estimates for Venezuelan crudes is a challenge due to a lack of data.

## Keystone XL is not the only option for moving oil sands

In the absence of Keystone XL, we would expect similar volumes of heavy Canadian oil sands to be produced. Industry would turn to alternative pipeline projects and rail for oil sands transportation. Even if new pipeline capacity does not keep pace with supply growth, rail movements can continue to grow. Given sufficient investment, our view is that the economics for moving heavy oil sands crude by rail could improve further, even approaching pipeline economics. Consequently, even without the Keystone XL pipeline, we believe that oil sands production would grow at a similar rate. Therefore GHG emissions will be unaffected by the fate of Keystone XL.

## If Keystone XL were denied: Alternative pipelines are likely

With such a large amount of oil sands pipeline capacity being advanced—and moving in all directions west, east, and south—it is reasonable to expect that eventually new pipelines will become available. Not including Keystone XL, the volume of proposed pipelines totals 3 mbd; 80% of this capacity connects the oil sands with Canada's west and east coasts and obviously does not require any US government approval.1 To put the potential capacity in perspective, we expect western Canadian supply growth between 2013 and 2020 will be about half of this volume.

The importance of new market access is not lost on the Canadian government. Following the president's delay of the Keystone XL pipeline decision in early 2012, Prime Minister Stephen

1. West coast options include the Northern Gateway (0.5 mbd) and Trans Mountain Expansion pipelines (0.5 mbd); east coast options include Energy East (1.1 mbd) and line 9 reversal (0.3 mbd). South options transit though the United States and include various expansions to increase the capacity and reach of the Enbridge mainline (0.5 mbd).

Harper declared, "Canada will continue to work to diversify its energy exports." [1]An important step toward this goal was made recently with the announcement of the Energy East pipeline project. If approved, it would connect 1.1 mbd of supply from Alberta with eastern Canada. Shortly after the project announcement, Canadian Natural Resources Minister Joe Olivier commented that Ottawa "welcomes the prospect of transporting Canadian crude oil from western Canada to consumers and refineries in eastern Canada and ultimately to new markets abroad."[2]

## Oil sands bitumen: A unique case for rail economics

Even if pipeline capacity lags oil sands growth, we expect that rail will be an ongoing and economic part of the transportation puzzle. For heavy oil sands crude specifically, in a scenario in which pipeline access was severely restricted, we would expect greater investments to make rail economics even more efficient, approaching those of pipelines.

Although moving crude oil by rail is generally more expensive than by pipeline, oil sands heavy oil could be an exception. What makes oil sands unique is the need for diluent. In its natural form, bitumen is the consistency of peanut butter—too thick for pipelines. Prior to pipelining, the bitumen is thinned by adding light hydrocarbons (typically natural gas condensates). The resulting mixture (called diluted bitumen, or dilbit) is about 70% bitumen and 30% diluents. This is how bitumen is transported today, whether by pipeline or rail.[3]

However, unlike pipelines, rail cars do not necessarily require diluent for moving oil sands. With the appropriate investment, they can transport pure bitumen, using heat to thin the bitumen during railcar loading and unloading.

By railing pure bitumen (instead of dilbit in a pipeline or rail car) oil sands producers can avoid some expense—specifically cost for the diluent—plus there would be fewer barrels to transport (compared with dilbit, shipping pure bitumen decreases the total volume moved by 30%). These savings offset some of the extra costs associated with rail transport. Assuming sufficient scale and investment, our view is that producer netbacks from the USGC for transporting pure bitumen by rail would be comparable to about $6 lower than for moving with pipeline (for each bitumen barrel produced). This compares favorably with netbacks for railing dilbit to the USGC, which would be in the range of $10 to $15 lower than pipeline for each barrel of bitumen produced.[4] Assuming the comparative economics between pipeline and rail were in this range ($6 per barrel or less), over the longer term, we would expect oil sands growth would not be affected, even if rail is an ongoing component of the transportation options for oil sands.[5]

1. Source Bloomberg retrieved August 2, 2013.
2. Source: CTV http://www.ctvnews.ca/business/transcanada-going-ahead-with-energy-east-line-between-alberta-and-n-b-1.1393327 retrieved August 2, 2013.
3. Dilbit moved by rail sometimes has slightly less diluent, between 20 and 25%.
4. Netbacks are calculated by subtracting cost of diluent and transport from revenue for each barrel of bitumen produced. Netbacks are appropriate for this comparison because the transportation costs cannot be directly compared since each case requires a different volume of total product moved. Relative pipeline economics assume a pipeline to the US Gulf Coast exists with tolls in the $7.50–9.00 per barrel range.
5. IHS CERA oil price outlook is that Brent crude will average $92 per barrel between 2013 and 2020 (constant 2011 dollars). Meanwhile, over the same time period, we expect oil sands steam-assisted gravity drainage projects to require a $65–85 per barrel Brent price for continued investment. Hence, even if oil sands break-evens were to increase by $6 per barrel owing to the use of rail, oil sands would continue to grow.

### Moving to pure bitumen by rail if pipelines are constrained

Pure bitumen rail movements today are not happening because the necessary infrastructure for shipping pure bitumen does not exist. Moving pure bitumen requires specialized equipment in Alberta, such as heated tanks connected by heated pipelines, modifications to rail on-loading facilities, heated rail cars, and units for removing diluent (diluent is added to the bitumen in the extraction and processing steps, this needs to be removed before shipping pure bitumen). In the USGC specialized rail off-loading facilities are also needed. The advantage today of moving dilbit, rather than pure bitumen, by rail is that it does not require as much unique rail infrastructure as pure bitumen. However, by moving dilbit by railcar, producers are making part of the investment needed for supporting pure bitumen movements.

The rationale, so far, for not investing in the pure bitumen transport option is that most oil sands producers are assuming that sufficient pipeline capacity will become available in a few years. In order to receive a payback on building pure bitumen railing infrastructure, producers must anticipate its use over a longer time frame—perhaps five years. However, if producers anticipate that new pipeline capacity will not keep pace with oil sands growth, we expect that they will make investments in more efficient rail transport, including equipment for moving pure bitumen. These investments would narrow the gap between the economics of transporting oil sands by pipeline and by rail. ■

IHS CERA

**Special Report**

# Critical Questions for the Canadian Oil Sands

October 2013 **ihs.com**

# Contents

## About this report

- **Purpose.** IHS CERA first researched questions critical for oil sands development in the 2009 Special Report *Growth in the Canadian Oil Sands: Finding the New Balance*. This update accounts for changes since that time and aims to illuminate critical questions for oil sands development, with a focus on areas of disagreement or uncertainty.

- **Context.** This report is part of a series from the IHS CERA Canadian Oil Sands 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. Participants include representatives from governments, regulators, oil companies, pipeline companies, academia, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at *www.ihs.com/oilsandsdialogue*.

- **Methodology.** This report includes multistakeholder input from a focus group meeting held in Washington, DC, on 13 November 2012 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 an introduction, seven sections, and a conclusion.
  - Introduction
  - Part 1: The role of oil sands in US oil supply
  - Part 2: Economics of oil sands compared with other supply sources
  - Part 3: Environmental regulation
  - Part 4: Regional environmental affects: Air, land, water, and waste
  - Part 5: Greenhouse gas emissions
  - Part 6: Technology
  - Part 7: Pipeline transport of oil sands
  - Conclusion

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IHS™ CERA®

**Special Report**

# Critical Questions for the Canadian Oil Sands


## Summary of key insights

This report is intended as a reference guide to the critical questions facing oil sands development. It updates our earlier work, the 2009 IHS CERA Special Report *Growth in the Canadian Oil Sands: Finding the New Balance*. Some key insights from this report are

- **Despite the rapid growth of US tight oil, the Canadian oil sands will continue to be an important component of US oil supply.** Even with tight oil, the United States will still need over 5 million barrels per day of net crude oil imports over the next two decades, and Canada will be key to helping meet this demand. Oil sands and tight oil are complementary—not competitive. New oil sands supply is expected to be heavy crude, while US tight oil is light crude. These two types of crude target different types of refineries.

- **Today more, not less, regulation, monitoring, and research are occurring in the oil sands.** The environmental impacts associated with oil sands growth are now better understood. Since the 2009 report, there are more rules and greater certainty about the sustainability of water use, the management of tailings accumulations, the impacts of land use on wildlife, and the impact of operations on regional air quality. However, questions still remain. For example, for mining operations, what will reclaimed land look like? And as in-situ operations expand, how will impacts on wildlife be managed?

- **Aggregate greenhouse gas (GHG) emissions from oil sands are regulated and are lower than often perceived, accounting for 7.8% of Canadian emissions and 0.14% of global emissions.** Oil sands GHG emissions are already regulated, and more rules are coming. Oil sands projects are subject to GHG regulation at the provincial level in Alberta, and Canada's federal government is developing new regulations as part of its nationwide target to reduce GHG emissions by 17% from 2005 levels by 2020—the same objective as the United States.

- **Oil sands crudes pose no greater risk to transmission pipelines than other crude oils.** Pipeline corrosion is well understood, and a number of scientific studies have concluded that the properties of oil sands crudes and pipelines that transport them are within the range of other crude oils. Consequently, oil sands crudes are no more likely to spill than other crudes.

– October 2013

# Introduction

Development of the oil sands encapsulates the complexity the world faces on energy, environmental, and security issues. Canada and most other oil producers are searching for the right balance between increasing oil supply—to accommodate growing economies, aspirations for higher living standards, and greater energy security—and protecting the environment.

This report is a new appraisal, following on the 2009 IHS CERA Special Report *Growth in the Canadian Oil Sands: Finding the New Balance* on the critical issues for oil sands development, and incorporates four additional years of research and experience.

Like our original report, this update identifies areas of uncertainty or disagreement that are central to the future development of the Canadian oil sands. Our goal is to create a reference document that illustrates complex issues clearly, to identify what is known and unknown, and to provide a common understanding for future discussions on oil sands development.

This report has an introduction, seven sections, and a conclusion:

- Introduction
- Part 1: The role of oil sands in US oil supply
- Part 2: Economics of oil sands compared with other supply sources
- Part 3: Environmental regulations
- Part 4: Regional environmental impacts: Air, land, water, and waste
- Part 5: Greenhouse gas emissions
- Part 6: Technology
- Part 7: Pipeline transport of oil sands
- Conclusion

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 signature feature of the oil sands is their immensity. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 168 billion barrels, making oil sands the world's third largest proven oil reserve (after Saudi Arabia and Venezuela). However, with advances in technology, as much as 315 billion barrels could ultimately become accessible from the oil sands.

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands is bitumen, an extra-heavy crude oil with high viscosity. Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with light oil or converted into a synthetic light crude oil. Several types of crude oils are produced from bitumen.

**Bitumen blends**. To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. A common bitumen blend is dilbit—short for diluted bitumen—typically about 70% bitumen and 30% lighter hydrocarbons. Going forward we expect the vast majority of oil sands supply growth to be bitumen blends.

**Synthetic crude oil (SCO).** SCO, which resembles light sweet crude oil, is produced from bitumen in refinery conversion units (called upgraders) that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. We do not expect meaningful future growth in SCO supply because of challenging economics.[1]

Oil sands are unique in that they are extracted through mining and in-situ processes.

**Mining.** About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface-mining process similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed and stockpiled for later use in reclamation. The layer of oil sands ore is excavated using massive shovels that scoop the material, which is then transported by truck to a processing facility. The original mining operations always marketed SCO. However, a new mining operation (which started up this year) does not include an upgrader and will instead ship bitumen blend straight to market. 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 39% of current oil sands production, and two commercial processes are used today:

- **Steam-assisted gravity drainage (SAGD)** is the fastest growing method, accounting for 25% of production in 2012 and by 2030 is is projected to account for almost 45% of oil sands production.
- **Cyclic steam stimulation (CSS)** was the first process used to commercially recover oil sands in situ. Currently making up 14% of total production, CSS is projected to account for less than 10% of total production in 2030.

**Primary production.** The remaining oil sands production is referred to as primary production. This material is less viscous and is extracted without steam, using conventional oil production methods. Primary production currently makes up 12% of total output and is projected to be less than 5% by 2030.

1. For more information on upgrading economics see the IHS CERA Special Report *Extracting Economic Value from the Canadian Oil Sands: Upgrading and refining in Alberta (or not)?*

# Part 1: The role of oil sands in us oil supply

This section explores the current and possible future role of oil sands supply in the US market and in strengthening North American energy security. We include a brief explanation of why increased oil sands supply to the United States is unlikely to contribute to higher gasoline prices, which has been a concern in the dialogue surrounding oil sands.

## What is the role of oil sands in US and global oil supply today?

Canada is the largest supplier, by a wide margin, of imported oil to the United States. In 2012 Canadian crude oil imports to the United States totaled about 2.4 million barrels per day (mbd), or about 28% of total US crude imports. Much of this—1.5 mbd, or about 18% of US imports— is from the oil sands.[2] In fact, the oil sands alone are now the largest foreign source of US oil supply, providing more oil than Saudi Arabia or Mexico (the second and third largest suppliers), which accounted for 16% (1.4 mbd) and 11% (1.0 mbd), respectively, in 2012. Even in the past few years, a time when total US oil imports have fallen sharply owing to the North American tight oil revolution and weak domestic demand, Canada's share of total US crude imports rose from 21% in 2010 to 28% in 2012. Despite the rapid growth of tight oil, we expect that the United States will still need over 5 mbd of net oil (liquids) imports each year over the next two decades. Oil sands are expected to remain an important pillar of US supply to meet this demand. Moreover, the two supply sources, tight oil and the oil sands, are complementary—not competitive. The vast majority of new supply from Canada is heavy crude, while most new US supply from tight oil is light crude. These two types of crude target different types of refineries, and both are important supply sources for North America.

More generally, Canada—and the oil sands in particular—has been a major source of global oil supply growth over the past decade and is poised to continue to be a key source of supply growth for the world. Canada is one of four countries included in what IHS CERA has called the "axis of oil supply growth," along with the United States, Brazil, and Iraq. We expect western Canadian crude oil output to rise from 3 mbd in 2012 to 5.9 mbd by 2030.[3] Considering other anticipated sources of growth, the oil sands could account for 16% of all new production globally until 2030.[4]

Although markets for oil sands are expected to diversify gradually, a large part of new oil sands supply through 2030 is expected to go to the United States—as virtually all of the production does today. By 2030, the United States could import more than 4 mbd of oil sands crudes from Canada.[5]

## How does oil sands production strengthen North American energy security?

The presence of the oil sands within the continent increases North American energy security. Increasing supply from Canada allows the United States to reduce its dependence on more distant supplies of oil by tanker, often from regions that are less stable and more susceptible to disruption. Pipeline and rail links between the United States and Canada constitute a "hardwired" link of Canadian oil to the US market—very different from waterborne shipments that can be diverted, even while en route.

2. The estimate of volume of US imports of oil sands is based on data from the Canadian National Energy Board (NEB) and the US Energy Information Administration (EIA). We have added 250,000 barrels per day (bd) to the reported values from the NEB to account for some oil sands blends that the agency categorizes as heavy conventional crudes.

3. Western Canadian production estimate does not include imported diluents added to non-upgraded bitumen for transport by pipeline.

4. This assumes that oil sands production grows by 2.6 mbd between 2012 and 2030 (not including diluents added to oil sands for shipping) and that over the same period global production grows by over 16 mbd.

5. Between 2012 and 2030 western Canadian supply is projected to grow by 2.9 mbd. Assuming that Gateway, Trans Mountain Expansion, and Energy East pipelines are constructed by 2030, there is the potential for 1.9 mbd of new western Canadian supply to be exported to other markets. This assumes that some oil transported by these pipelines will still be exported to the United States, by tanker or barge.

Complex refineries on the US Gulf Coast (USGC), the largest heavy oil refining complex in the world, require heavy crude like bitumen blends from the Canadian oil sands. The region currently relies on heavy crude oil from Mexico and Venezuela. Mexico has struggled to maintain its heavy crude output to the USGC. Between 2005 and 2012, imports of Mexican heavy crude to the United States have declined by about half.[6] In the first six months of 2013, the United States averaged just over 750,000 bd of heavy crude oil imports from Venezuela.[7] There is also some uncertainty surrounding future supply from Venezuela, stemming from a recent history of declining production. Canadian heavy supply offers an alternative to less certain heavy crude suppliers.

All sources of oil supply contribute to global spare capacity and price stability. All else being equal, without the Canadian oil sands, the world's spare production capacity cushion would be less than it is now. The thinner this cushion is, the more susceptible the price of oil is to unanticipated changes in supply and demand. By the end of this year Canadian oil sands production will be roughly equivalent to about two-thirds of estimated global spare production capacity for 2013.[8] We expect global spare production capacity in 2020 to average about 4.3 mbd, which is higher than the 2 to 3 mbd of recent years. The 1.4 mbd of oil sands production growth over this time would be an important contribution to a greater global supply cushion.

## How will new oil sands pipelines affect US gasoline prices?

For the past few years, the price of inland North American crudes has been below—significantly at times—the price of crude oil on the USGC. These North American crudes—not only from Canada and the oil sands but also from North Dakota—have traded at a discount compared with the cost of similar crudes available globally. This is because the expansion of the inland pipeline network has struggled to keep pace with the rapid growth of onshore supply, resulting in a glut of oil in the US Midwest. If proposed pipelines are completed, the oversupply situation in the US Midwest will be resolved, and crude prices would strengthen as they reconnect with global market prices.

There is a view that this would also cause prices for refined products, such as gasoline, in the Midwest to increase. However, this is not the case.

The global price of oil is the most important factor shaping global and US gasoline prices. Although the price of inland North American crudes has been below the price of crudes on the USGC, this spread has not been reflected in inland North American gasoline prices, which have tracked USGC prices. For example, in 2012 the difference between Louisiana Light Sweet on the USGC and West Texas Intermediate (WTI) in Cushing, Oklahoma, averaged over $17 per barrel, compared with an average of $3.35 in 2010, before infrastructure bottlenecks became pronounced. Despite the wide price difference for crudes in the Midwest compared with the USGC, the price of gasoline in the two areas has remained very close. In 2012 the price in the Midwest averaged $2.89 per gallon, only $0.02 higher than on the USGC. This is because the price of gasoline in both regions, and elsewhere in the United States, is set on the world market. Prices in all regions are linked because gasoline is shipped from the USGC through the refined product pipeline network and by water to consumers in the Southeast, the East Coast, the Midwest, and the West. As a result, increased oil sands imports to the USGC and other US markets will not have a material impact on US gasoline prices in any market. However, as oil sands production expands, as discussed above, it can help boost global spare capacity, which can help moderate global prices, which in turn affects US gasoline prices.

6. Mexican Maya imports in 2012 were 0.7 mbd, compared with 1.3 mbd in 2005.

7. We define heavy crude oil as having an API gravity of less than 28 degrees. Source of import data: US EIA.

8. By the end of 2013, oil sands production of SCO and non-upgraded bitumen is expected to average over 1.9 mbd. We project that global spare capacity will average about 2.9 mbd in 2013.

# Part 2: Economics of oil sands compared with other supply sources

This section explores how the economics of oil sands production compare with other sources of supply.

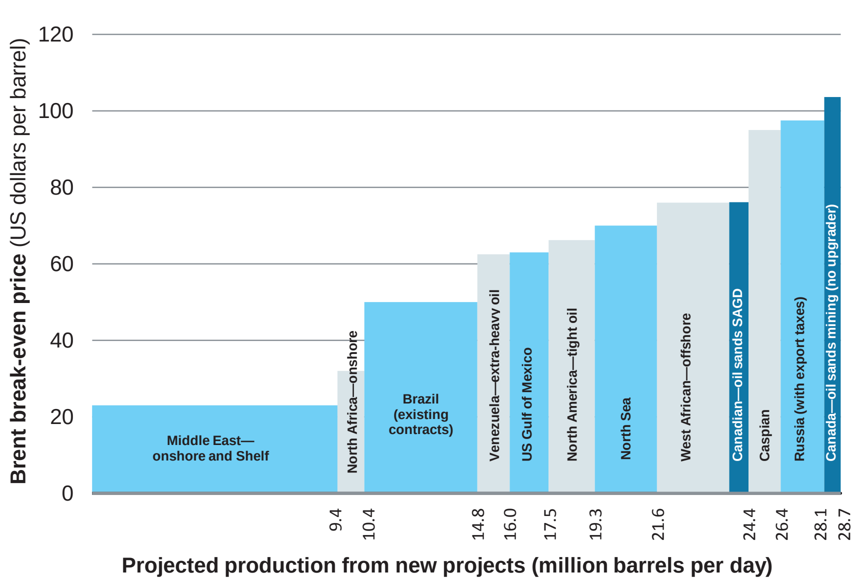
## How costly are the oil sands compared with other new sources of supply?

Oil sands are one of a group of higher-cost supply sources that are being developed globally. Oil sands development costs are higher than those for conventional resources being developed in the Middle East and North Africa. However, the cost of oil sands production that uses SAGD technology is in the same range as new supplies from the North Sea, Brazil offshore, and West Africa offshore.

Figure 1 compares the economics of a number of oil projects currently under development. The projects, grouped by type, represent about 90% of new production capacity expected to come online between now and 2020.[9] The economic analysis of each development first considers finding, development, and production costs, then taxes and royalties, transportation, and crude quality differences. It then evaluates the threshold Brent price (a global crude benchmark price) required to obtain a reasonable return on capital investment—we assume 10% for oil sands and North American tight oil and 15% for all other international projects, which have a higher investment risk.[10]

FIGURE 1

**Brent break-even price for new crude supply to 2020**




Note: The required Brent oil price is based on full-cycle costs that include finding, development, and production and an internal rate of return (IRR). IRR is 15% for all areas, except for Canadian oil sands and North American tight oil, for which it is 10%. Middle East onshore and shelf breakeven price is for Saudi Arabia. North African onshore breakeven price is for Libya. For Venezuela extra-heavy, breakeven price is for projects under the strategic association agreements for production of extra-heavy oil in the Orinoco region, which includes a royalty holiday and tax benefits for vertically integrated producers (i.e., those with both upstream and upgrading operations). For Brazil, production is all under existing concession royalty contracts, with the exception of 600,000 bd from Franco. Franco is a "Transfer of Rights" field, i.e., a field that the Brazilian government gave to Petrobras under special terms to capitalize the company prior to its initial public offering. For Canada oil sands mining, the breakeven price assumes that no upgrader was used and that the facility markets dilbit. The breakeven prices for the oil sands and tight oil are for WTI and are converted into a Brent basis by adding $4 to reflect quality differentials and the cost of transporting the crude from inland areas in North America to a port where it competes directly with Brent (assumed to be on the US East Coast). This $4 supplement represents our annual average price outlook to 2020 for WTI less Brent.

Source: IHS Energy



9. The projects in Figure 1 represent about 29 mbd of new supply—about 90% of the total new capacity we expect to come online by 2020.
10. Brent crude oil is a globally traded crude, based originally on North Sea production, that is often used as a global crude benchmark price.

# Part 3: Environmental regulation

With oil sands production expected to more than double between 2012 and 2030, there are concerns about whether existing environmental regulations can address the impacts of such growth.[11] Provincial and federal governments in Canada are responding by issuing new regulations and by expanding monitoring. This section highlights key changes to the environmental regulatory framework for the oil sands in the past few years. Part 4 examines in detail the specific regional environmental impacts and regulation for air, water, land, and waste in the oil sands region. Part 5 presents an outlook for greenhouse gas (GHG) emissions from the oil sands.

## How does environmental regulation of oil sands compare with resource development in other regions?

Environmental regulation of oil sands projects is generally similar to that of natural resource development projects in peer areas. IHS CERA compared regulation in oil sands to two peers: South Australia's mining sector and Alaska's mining and oil sectors. Similarities in regulation include the project approval process, the use of inspections and nature of enforcement, and requirements for environmental monitoring and site closure.[12]

## What changes are under way for oil sands regulation?

Over the past few years, Canada's federal and Alberta's provincial governments introduced new policies and regulations to address the growing scale of oil sands development. The most significant of these aim to

- Clarify and streamline the project environmental assessment process
- Move to a system that assesses the cumulative effects of development
- Consolidate and enhance environmental monitoring

### *Clarifying and streamlining the project environmental assessment process*

Each oil sands facility undergoes a project-specific review process at the provincial level. In addition, projects may also require federal permits that can involve a federal environmental review.[13] Projects that trigger multiple federal permits or are of high public interest may require a coordinated federal review by a panel. Where overlap occurs with provincial reviews, the review panel may be held in cooperation with the province; this is called a joint federal-provincial review panel. Joint reviews are generally more exhaustive than other reviews because they typically involve larger, more complex projects that have the potential for significant environment impacts.

It is a common misconception that the sole purpose of an environmental review is to deliver a yes or no decision. Though review panels do make recommendations, environmental assessments also serve as an important planning tool to inform project proponents, regulators, and stakeholders about the potential impacts of the development. It provides a forum for all parties to discuss and, to the extent possible, mitigate

11. Oil sands production of SCO and non-upgraded bitumen is expected to rise by 2.6 mbd between 2012 and 2030, to nearly 4.4 mbd. When diluent is included (some of which is imported into Canada), total oil sands supply is expected to rise by 3.5 mbd, to 5.6 mbd, over this period.

12. See the IHS CERA Special Report *Assessing Environmental Regulation in the Canadian Oil Sands*.

13. Key federal departments/agencies with regulatory responsibilities most likely involved in oil sands developments include the Canadian Environmental Assessment Agency, Transport Canada, the Department of Fisheries and Oceans, and Environment Canada.

potential adverse effects from the development.[14] Panel recommendations take into account whether potential impacts are justifiable. Rarely does a project go through the environmental review process only to be denied.[15]

In recent years, industry and governments have argued that the review process has become increasingly burdensome—raising costs and uncertainty for the companies seeking to undertake industrial projects in Canada. For instance, projects may not always trigger a joint review panel but may still require multiple permits from both levels of government. Separate reviews by both federal and provincial regulators increase both time and cost for project proponents. Also, when joint review processes are triggered, they have become increasingly lengthy. In one recent example, an oil sands project took nearly six years to receive a final decision.[16]

Greater public interest, even from organizations and people far removed from the project, has been one factor that has contributed to a lengthier review process. In one recent example, more than 4,400 individuals asked to speak at public hearings of the joint review of the proposed Northern Gateway pipeline. This volume of requests contributed to a one-year extension of the regulatory time frame.[17] A review of the Northern Gateway hearing database shows requests to address the panel from across Canada (British Columbia, Alberta, Saskatchewan, Ontario, Québec, and the Maritimes), but also from the United States and as far away as England.[18]

With an eye toward reducing duplication and improving the timeliness of reviews, in 2012 the Government of Canada revamped the federal rules for environmental assessments of industrial projects, including oil sands.[19] Key aspects of the new Act include predefined criteria for determining when federal environmental assessments must be conducted; time limits for reviews (12 months for a comprehensive environmental review and 24 months for a joint review panel); the potential for provinces to substitute their environmental reviews in place of a federal review; and restricting those who can orally address the review panel to subject matter experts and those directly affected by the proposed project.[20]

The revised federal environmental assessment rules have faced some criticism for being potentially less rigorous. This is in part because the new rules impose time limits and reduce public participation, but also because they are expected to result in fewer federal reviews owing to possible substitution with provincial processes. However, the impacts of the new process will become clearer over time, as reviews of the first tranche of projects subject to the new guidelines run their course.

14. For more information, see Canadian Environmental Assessment Agency, Basics of Environmental Assessment, *www.ceaa-acee.gc.ca/default.asp?lang=en&n=B053F859-1#gen02*, accessed 9 October 2013.

15. The last major project that was denied approvals was the Prosperity Mine in British Columbia, in 2010. The federal review found that the significant adverse effects could not be justified. This resulted in the reworking of the project proposal, and the revised project is back under review, with a decision expected early in 2014. For more information, see *www.ceaa.gc.ca/050/document-eng.cfm?document=46185*, accessed 29 July 2013; and for the new review submitted 9 August 2011, see *www.ceaa-acee.gc.ca/050/details-eng.cfm?evaluation=63928*, accessed 29 July 2013. In another rare example, although not a panel review, in 2012 the Alberta Energy Regulator (at the time the Energy Resources Conservation Board) denied E-T Energy Ltd.'s Poplar Creek project because the regulator did not have enough information to conclude if the technology E-T wished to pilot could sustain commercial production rates. For more information, see *www.e-tenergy.com/media/files/upload/ETEL_PR_June_14_2012_ERBC_Decision_sxq.pdf*, accessed 31 July 2013.

16. The Jackpine Expansion review is closing in on six years (20 December 2007 to present). Barring any extensions, a final decision is expected by the Minister of Environment before to 6 November 2013—120 days following the submission of the joint review panel report on 9 July 2013. Source: Canadian Environmental Assessment Agency, Jackpine Mine Expansion Project Documents, *www.ceaa-acee.gc.ca/050/documents-eng.cfm?evaluation=59540*, accessed 23 July 2013.

17. As of July 2013 the Joint Review Panel had received 4,455 requests to make an oral statement and 5,444 letters of comment. Source: Enbridge Northern Gateway Project Joint Review Panel Public Registry, "F – Letters of Comment" and "G – Requests to Make an Oral Statement," *https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/384192/620327/customview.html?func=ll&objId=620327&objAction=browse&sort=-name&redirect=3*, accessed 14 October 2013. On 6 December 2011, the Joint Review Panel issued a new hearing schedule that delayed the final Northern Gateway project decision until late in 2013, a year later than previously expected.

18. Enbridge Northern Gateway Project Joint Review Panel Public Registry, "G – Requests to Make an Oral Statement," *https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/384192/620327/G_-_Request_to_Make_an_Oral_Statement_file.html?nodeid=838062&vernum=0*, accessed 14 October 2013.

19. The federal government enacted the Canadian Environmental Assessment Act, 2012, which replaced a similarly named law passed in 1992. For more information, see *www.ceaa-acee.gc.ca/default.asp?lang=en&n=16254939-1*, accessed 9 October 2013.

20. For more information on the Canadian Environmental Assessment process and Act, see *www.ceaa-acee.gc.ca/default.asp?lang=en&n=B053F859-1*, accessed 29 July 2013.

### *Moving to a system that assesses the cumulative effects of development*

Although each oil sands project must undergo a thorough review process, concerns about the cumulative impact of development on the oil sands region as a whole have emerged owing to the scale of development and the growing number of projects. In response to this issue, in 2012 Alberta introduced a regional plan for the main oil sands development area, the Lower Athabasca Regional Plan (LARP).[21]

Under LARP, industrial project environmental reviews take into account regional environmental limits in addition to project-level requirements. Environmental impacts (including on air and water quality) from all industrial development (including oil sands) are required to stay within the regional limits.[22] Actions to mitigate negative environmental effects must be taken to address upward trends before regional limits are reached. For now, indicators for regional air and water quality are still below limits. This is not a surprise, since the concern is directed more toward future effects if all approved projects are constructed. It remains to be determined how individual facilities, not only from the oil sands but from all sectors, might be required to reduce their environmental impact in the event that levels approach regional limits, since the burden is on all sources from the area rather than an individual facility.

In addition to managing the cumulative effects of development, LARP also designates new conservation areas: 22% of the region's total area is protected, an area almost the size of the state of New Jersey.[23]

Although LARP was announced last year, it will take several years for all aspects of the plan to come into force. Some initiatives are taking longer than anticipated, such as the groundwater management framework for the lower Athabasca, the biodiversity framework, and the tailings management framework. Specific examples of regulatory changes resulting from LARP are highlighted, where appropriate, in Part 4, which reviews regional environmental impacts.

### *Consolidating and strengthening environmental monitoring*

Regional air and water quality are monitored in the oil sands region by the Wood Buffalo Environmental Association (WBEA) and the Regional Aquatics Monitoring Program (RAMP), respectively.[24] WBEA, which has been in place for over a decade, actively monitors air quality at 16 locations (18 by the end of 2013), and periodically at 23 boreal forest sites, and measures some 214 air quality indicators.[25] In addition, each oil sands facility is required to monitor and report on air and water quality and biodiversity for each site.

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21. The Lower Athabasca region is the main oil sands development area in Alberta, accounting for 83% of the province's oil sands resources. The oil sands in Alberta, in turn, represent more than 95% of Canada's total oil reserves. LARP is the first of seven regional plans under Alberta's Land-use Framework to be approved. See Government of Alberta, *Lower Athabasca Regional Plan 2012–2022*, 2012, *https://landuse.alberta.ca/LandUse%20Documents/Lower%20Athabasca%20Regional%20Plan%202012-2022%20Approved%202012-08.pdf*, accessed 13 September 2013. For resource estimates, see Alberta Energy Regulator, ST-98-2013 *Alberta's Energy Reserves 2012 and Supply/Demand Outlook 2013–2022*, *www.aer.ca/documents/sts/ST98/ST98-2013.pdf*.

22. Other major industrial sectors in Alberta include forestry, natural gas, minerals, and agriculture.

23. The total Lower Athabasca region is 35,989 square miles (sq mi), or 93,212 square kilometers (sq km). Within this region, the total conservation areas are more than 7,722 sq mi or 20,000 sq km. The area of the state of New Jersey is 8,204 sq mi, or 21,248 sq km. Sources: Government of Alberta, Lower Athabasca Regional Plan 2012–2022, 2012, *https://landuse.alberta.ca/LandUse%20Documents/Lower%20Athabasca%20Regional%20Plan%202012-2022%20Approved%202012-08.pdf*, accessed 13 September 2013; and The State of New Jersey, Fast Facts, *www.state.nj.us/nj/about/facts/facts/*, accessed 13 September 2013.

24. Both WBEA and RAMP may be subject to change owing to the implementation of a Joint Federal-Provincial Monitoring Program. For more information on WBEA, see *www.wbea.org*. For more information on RAMP, see *www.ramp-alberta.org*.

25. Periodic monitoring, or passive monitoring, is more useful to detect longer-term trends, whereas active monitoring provides more up-to-date air quality measurements. Source: WBEA monitoring information provided by WBEA.

In 2012 the Alberta and federal governments jointly unveiled a plan to strengthen monitoring activities in the oil sands region. Scheduled for full implementation by 2015, the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring was a response to concern by scientists and governments in Canada that the existing level and structure of monitoring in the oil sands regions were insufficient to capture the effects of oil sands development. The new plan will increase the number of sites and extend the reach of the existing regional monitoring system.[26] One goal of the new program is to measure the impacts from oil sands development on regional air, water, land, and biodiversity in an integrated way. Another goal is to ensure that the system is adaptive, incorporating experience (gained through past monitoring) and new scientific and technical knowledge. Transparency is another objective. A new data management system, the Oil Sands Data Management Network, will be used to increase public access to monitoring data. The improved monitoring is critical to supporting LARP, as thresholds will need to be measured at the regional level to understand whether cumulative effects are within mandated limits.

26. For more information on the joint monitoring plan, see Canada-Alberta Oil Sands Environmental Monitoring Information Portal, *www.jointoilsandsmonitoring.ca*. For information on concerns about prior monitoring, see Environment Canada, Lower Athabasca Water Quality Plan, Phase 1, *www.ec.gc.ca/Content/8/A/1/8A1AB11A-1AA6-4E12-9373-60CF8CF98C76/WQMP_ENG.pdf*, accessed 13 September 2013.

# Part 4: Regional environmental affects: Air, land, water, and waste

This section examines the regional environmental impacts associated with oil sands development: air pollutants, land use and reclamation, water use, and waste (tailings). GHG emissions are examined in the next section.

## Air pollutants

Oil sands facilities emit air pollutants that degrade air quality. The type of air pollutants emitted by oil sands operations are similar to those found in urban or other industrial areas.[27] When air pollutants find their way back to earth, they can accumulate in water and soil and can affect human and wildlife health if present at sufficient concentrations.

### *Air quality*

Compared with that of major urban centers in Alberta and Canada, the air quality in the oil sands region is better on average.[28] Although most airborne contaminants remain relatively localized—within about 15 mi (25 km) of oil sands operations—evidence has been found of contaminants, specifically PAH, accumulating in lakes up to 55 mi (90 km) away.[29] However, current measured levels of PAH concentrations in lakes do not pose a health risk and are comparable with levels found in water in urban environments. As development expands other evidence of industrial activity will grow.

### *Regulating and monitoring*

Regulations are in place to limit air emissions from each oil sands facility.[30] Facilities must monitor and report air emissions to the government on a regular basis. In addition, new regional limits were implemented in 2012 under the Alberta Air Quality Management Framework (part of the Land-use Framework, discussed above). These new thresholds aim to manage emissions from all sources, including industrywide impacts on the region's air quality (as opposed to facility-level emissions limits). A key requirement in enforcing regional air pollution limits is measuring pollutants over a wide area. Plans to strengthen regional monitoring are discussed in more detail above in Part 3.

### *Future levels of air pollution and regional thresholds*

Although air quality in the oil sands is typically better than in major urban cities, air pollutants are set to increase in line with rising oil sands production. Indeed, a recent cumulative environmental assessment completed as part of an oil sands mine regulatory review has confirmed that if all planned oil sands projects are built and no new air pollutant measures are taken, the levels of air pollutants such as nitrogen dioxide ($NO_2$) and sulfur dioxide ($SO_2$) could exceed regional limits under Alberta's new air quality regulations.[31]

27. Some common air pollutants resulting from oil sands operations are sulfur oxides ($SO_x$), nitrogen oxides ($NO_x$), and particulate matter. Other pollutants include volatile organic compounds, total reduced sulfurs, and polycyclic aromatic hydrocarbons (PAH).

28. Using a modified Environment Canada/Health Canada Air Quality Health Index (AQHI), for 98% of the time over the past five years, air quality in the oil sands region posed a low risk to human health. Oil sands air quality was estimated from the share of low risk records (as measured by an AQHI index of three or less) from 2007 to 2012 from the summation of records for Fort McMurray and Fort McKay. Urban records include Edmonton and Calgary, which both reported that 81% of the time, air quality was low risk over last five years. For more information, see the Clean Air Strategic Alliance, Data Warehouse, *www.casadata.org*.

29. See K. Percy (2013), *Alberta Oil Sands: Energy, Industry, and the Environment, Developments in Environmental Science 11, Oxford, UK*; *http://www.elsevier.com/books/alberta-oil-sands/percy/978-0-08-097760-7#*, accessed 9 October 2013. Also, see J. Kurek et al. (2013), "Legacy of a half century of Athabasca oil sands development recorded by lake ecosystems," Proceeding of the National Academy of the Sciences of the United States of America, *http://www.pnas.org/content/early/2013/01/02/1217675110*, accessed 9 October 2013.

30. Air pollution regulations are diverse and are contained in a variety of federal and provincial legislation in Canada. At the federal level, the Canadian Environmental Protection Agency Act 1999 sets limits and requires reporting of industrial emissions. In Alberta, the Air Quality Management System provides provincial direction.

31. Source: Shell Canada Energy's Response to the Joint Panel's Information Requests, Jackpine Mine Expansion Joint Panel Review, September 7, 2012, *www.ceaa-acee.gc.ca/050/documents/p59540/81301E.pdf*, accessed 14 October 2013.

If levels approach regional limits, industry would need to reduce pollutant levels. Reductions can be achieved at a financial cost, but currently it is unclear who would bear this burden—whether it would be industrywide or just involve the most recent facility. Some potential abatement options include obtaining newer, more efficient, mining trucks or deploying new technologies, such as emission scrubbers or systems to capture key air pollutants.

## Land use and reclamation

The decision to develop the oil sands has resulted in land being disturbed. Oil sands operations require land to access oil sands deposits and to house their extraction, processing, and transportation equipment. The predevelopment state of land in the oil sands region is boreal forest. Evergreen trees dominate the landscape, and 30–40% of the boreal areas are wetlands.

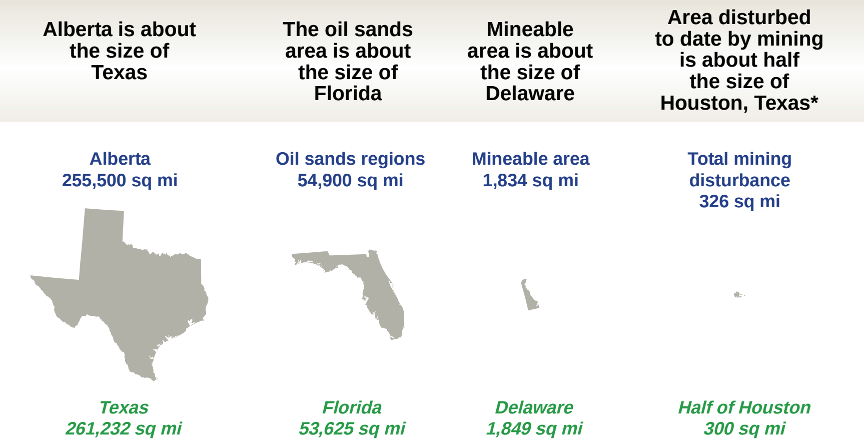
Land disturbed by oil sands operations is degraded or removed from the ecosystem for a period of time. This affects wildlife and local residents, particularly Aboriginal peoples who use the land for traditional activities such as hunting, trapping, and fishing. As the scale of oil sands development has grown, the amount of disturbed land has increased. The degree to which land is disturbed and the challenge of reclamation vary according to whether the oil sands operation is in-situ or mining. These differences are highlighted below.

### *Footprint of oil sands development*

As shown in Figure 2, Alberta is about the size of Texas, and the oil sands region within the province is about the size of Florida. Within the oil sands region, the area suitable for surface mining is just over 3% of the total oil sands area—an area comparable to the state of Delaware. The remaining 97% of the oil sands areas are suitable for in-situ extraction techniques. At any given time, only a small part of the mineable or in-situ areas is expected to be under active development. As of the end of 2012, about one-fifth of the total mineable area had been disturbed—an area 326 sq mi in size, similar to half of Houston proper. While the potential in-situ development area is a considerable size, individual in-situ project footprints and their resulting disturbance are small compared with mining operations and are more comparable to conventional oil and gas footprints, with well pads and pipelines.[32]

FIGURE 2

**Illustrative comparison of various oil sands areas to some US areas**




31026-2
Note: Images are approximations and are not to scale.
*Includes area under active disturbance, 296 square miles and reclaimed areas, 30 square miles as of the end of 2012.
Source of oil sands areas from Alberta Energy, www.energy.gov.ab.ca/LandAccess/pdfs/OSAagreeStats.pdf; source of oil sands disturbance Alberta Environment and Sustainable Resource Development (ESRD), Oil Sands Portal, Oil Sands Mine Regional Totals for Reclamation and Disturbance Tracking by Year, environment.alberta.ca/apps/OSIPDL/Dataset/Details/27#, accessed 24 September 2013.
Source of area of US states (2010), US Census Bureau, State and Country QuickFacts, quickfacts.census.gov/qfd/index.html; area of Houston proper from Greater Houston Convention and Visitors Bureau, www.visithoustontexas.com/travel-tools/about-houston/facts-and-figures/.
Source: IHS CERA



32. Alberta occupies 255,000 sq mi (661,000 sq km), and oil sands deposits in Alberta underlie an area of 54,900 sq mi (142,200 sq km). The minable region occupies an area of about 1,833 sq mi (4,750 sq km). The total area disturbed by mining operations as of the end of 2012 was 326 sq mi (844 sq km) and is made up of reclaimed land area of 30 sq mi (78 sq km) and active mining disturbance of 296 sq mi (766 sq km). The total area suitable for in-situ development is 53,070 sq mi (137,450 sq km). Disturbed land is defined as an area where natural vegetation has been partially or totally cleared, wetlands have been drained, or the land has otherwise been changed from its natural ecological state. Source of disturbance data: Alberta Environment and Sustainable Resource Development (ESRD), Oil Sands Portal, Oil Sands Mine Regional Totals for Reclamation, and Disturbance Tracking by Year, *environment.alberta.ca/apps/OSIPDL/Dataset/Details/27#*, accessed 24 September 2013.

### *Land disturbance and reclamation: mining*

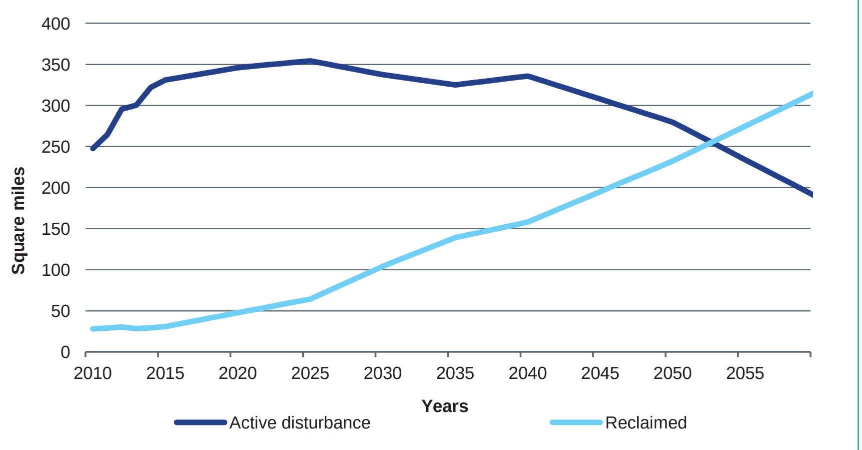
Although the total mineable area is smaller than the in-situ development area, mining requires the removal of all material overlaying the oil sands deposits before mining can commence.[33] This represents a total loss of the ecological character of the land for a period of time and highlights the importance of reclamation in returning the lands to productive use.

Large-scale commercial oil sands mining began over 45 years ago, in 1967.[34] As new projects have come online and mining has progressed, the amount of disturbed land has increased. However, reclamation has not progressed at the same rate. With mining operations lasting for more than 40 years, the current practice has been to mine-out large areas before performing large-scale reclamation. At the end of 2012, total active disturbance (disturbed land less reclaimed land) was 296 sq mi—30 sq mi less than shown in Figure 2, which accounts for areas under various stages of reclamation (0.4 sq mi of this has been certified as reclaimed).[35] Increasingly governments and industry are looking at ways to accelerate reclamation. One often discussed method is progressive reclamation, which involves planning a mine to more readily allow operators to reclaim as they go.

Although the amount of disturbed land has been growing steadily, based on expectations set forth in projects' approved reclamation plans, the pace of growth is projected to slow. Figure 3 depicts the result of the latest mine reclamation and closure plans submitted to Alberta ESRD. As older mines approach the end of their life, the pace of reclamation is projected to pick up. In the absence of new mining projects, between now and 2060 the total area of active disturbance is expected to be at most 20% larger than it is today.[36]

FIGURE 3

**Oil sands mining footprint: Outlook for disturbed and reclaimed land**




Note: Historical data used for years 2010 to 2012 inclusive form Alberta Oil Sands Portal. See: Alberta ESRD, Oil Sands Mine Regional Totals for Reclamation and Disturbance Tracking by Year Description, http://environment.alberta.ca/apps/OSIPDL/Dataset/Details/27, accessed 17 October 2013. Mine disturbance and reclamation for the years 2013, 2014, 2015, and every five years after to 2040, then 2050 and 2060 from mine reclamation and/or mine closure plants submitted to Alberta ESRD. Line interpolated between data points. Provided directly by Alberta ESRD.Mine reclamation and/or mine closure plans included: Syncrude Canada Ltd. Mildred Lake Canada (2011) and Aurora (2011), Canadian Natural Resources Horizon (2011), Suncor Energy Inc. base mine (2011), and Fort Hills (2011), Shell Muskeg River (2012), and Jackpine (2011), Imperial Kearl (2011).

Source: IHS CERA and Alberta ERSD



When land is disturbed on the scale of oil sands mining operations, the land is permanently changed. The extent to which reclaimed land will resemble its predisturbance state is an open question. The reclamation of wetlands, which cover two-thirds of the oil sands mineable area, is of particular concern. The re-creation of some types of wetlands, such as fens and bogs, is more challenging; and although research and large demonstration projects are under way, successful reclamation of these types

33. Overburden, or the material that overlies an oil sands deposit, consists typically of clay, sands, soils, and organic material including plants and vegetation.

34. The first oil sands mine commenced operations in 1967, producing 45,000 bd. Source: Suncor Energy, *www.suncor.com/en/about/744.aspx*, accessed 24 September 2013.

35. According to Alberta's Environmental Protection and Enhancement Act, before land can be certified as reclaimed it must have equivalent capability as its predevelopment state. For more information, see Alberta's Environmental Protection and Enhancement Act, 2000, *www.qp.alberta.ca/1266.cfm?page=E12.cfm&leg_type=Acts&isbncln=9780779735495*. For more information on land disturbances and reclamation, see Alberta ESRD, Oil Sands Portal, *http://environment.alberta.ca/apps/osip/*.

36. The maximum active mining footprint is expected to be reached in 2025, at 354 sq mi. See Figure 3 for more information.

of habitat remains an area of active research (see the section "Evolving policy and technology for land reclamation" below).

### *Land disturbance and reclamation: In situ*

Compared with mines, in-situ operations disturb less land. Overburden is largely left in place, with only forest and vegetation removed for well pads, processing areas, and access corridors. This impacts about 7–15% of an in-situ lease area.[37] Also, the disturbance of land in an in-situ development takes place over a shorter period since the life of a well is shorter than that of a mine. For example, Imperial Oil's Cold Lake in-situ operation has been active since 1985, and 19% of its disturbed land, principally access roads and retired well pads, has been reclaimed.[38]

For in-situ operations, the way in which land is disturbed can impact wildlife in an area greater than the physical footprint. In-situ operations create linear corridors through the forest where the trees and vegetation have been removed to support infrastructure such as roads, pipes, and seismic lines. These linear disturbances, though relatively small as a percentage of land disturbed, fragment forests, affecting wildlife in an area beyond the footprint of the development by altering the mobility and interaction of forest animals.

The woodland caribou, a species at risk in Canada, is particularly vulnerable to linear disturbances.[39] Their population is declining in Canada, including the five known herds within the oil sands regions. In 2012 a Canada-wide federal Recovery Strategy for Woodland Caribou was released. It confirmed that linear disturbances from industry (oil sands, forestry, and other industrial activity) contributed to the decline—disturbing the caribou's habitat and increasing contact with predators.[40]

In response to the federal recovery strategy, Alberta and other provincial governments must now develop action plans (e.g., regional recovery strategies), expected by the end of 2015. It is possible that the rules will require oil sands operators to reduce project footprints and set more aggressive reclamation targets (including reclaiming beyond oil sands lease areas, such as lands disturbed from prior industrial development from conventional oil and gas or forestry). This could also require the culling of wolves, the primary predator risk for caribou.

### *Evolving policy and technology for land reclamation*

As part of LARP, Alberta is committed to developing new policies to push for more rapid reclamation and reduction of disturbances in the oil sands region. The land-use plan includes commitments to encourage better sharing of existing footprint, such as access roads, between industrial users, forestry stakeholders, and oil and gas companies.

Also, research is under way to better understand methods to reclaim land disturbed by oil sands activity. Canada's Oil Sands Innovation Alliance (COSIA), a group of oil sands producers formed in 2012, is studying ways to accelerate land reclamation from mines, including harder-to-construct habitats such as wetlands and muskeg (a type of peat-rich wetland). For example, as part of COSIA, Syncrude, a major oil sands producer, has constructed a 17 hectare fen, a type of wetland, on a former mined pit to study and demonstrate how to reclaim these more challenging types of ecosystems on a large scale. Suncor, another major oil sands

37. The land disturbance resulting from in-situ developments is generally—but not always—somewhat higher than for conventional oil developments.

38. Source: Imperial Oil, *www.imperialoil.ca/Canada-English/operations_sands_glance_land.aspx*, accessed 24 July 2013.

39. In Canada, a species is considered at risk when its population is declining and at risk of becoming endangered or non–self-sustaining.

40. According to the 2012 federal Recovery Strategy for Woodland Caribou, 62% to 85% of the caribou's habitat within the oil sands region has been disturbed from natural (fire) and industrial activity (forestry and oil and gas). For more information, see Recovery Strategy for the Woodland Caribou, *www.sararegistry.gc.ca/document/default_e.cfm?documentID=2253*, accessed 23 July 2013.

producer and a member of COSIA, is also undertaking a similar project to reclaim a fen.[41] COSIA is also maintaining and growing a seed bank to ensure that a variety of plant species native to the boreal forest are available for reclamation in the future.

## Water use

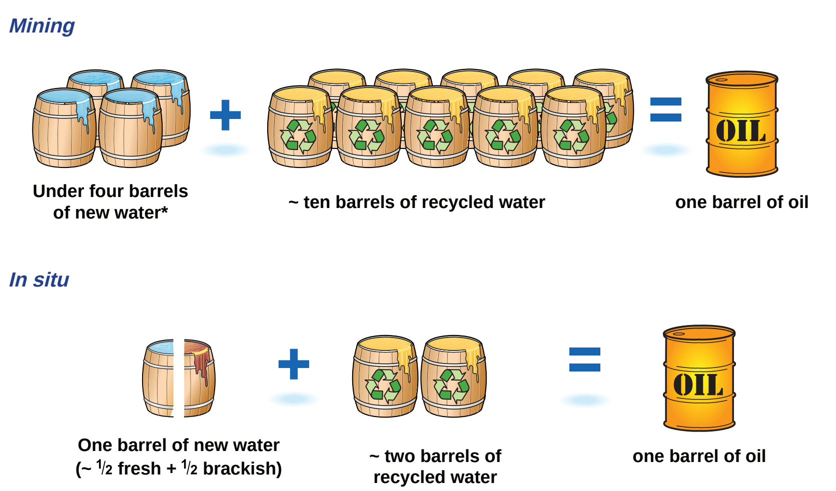
Water is used in oil sands extraction to separate the bitumen from the sand. In-situ operations get most of their water from underground sources, while the Athabasca River remains the main water source for mining operations. Water is critical to the local ecosystem—for local residents, wildlife, and fish habitat. And, without water, oil sands extraction could not take place. Anticipated growth in oil sands production has raised questions about the sustainability of future water demands. Although uncertainty exists, if new practices and technologies are deployed, water should not be a limiting factor in oil sands growth.

### *How does oil sands water intensity compare with other types of energy?*

The water intensity of oil sands operations is comparable to other types of energy production. Oil sands extraction makes use of both "new" water that is withdrawn from the environment and recycled water. On a net basis, for each barrel of bitumen produced, an oil sands mining operation withdraws up to four barrels of new water from the environment, whereas an in-situ operation draws less than one barrel (see Figure 4).[42] An additional barrel of water is used per barrel of bitumen in refining and processing. This brings the total life-cycle water use to produce oil sands and convert them to useable refined products to around two barrels and five barrels per barrel of output for in-situ operations and mining, respectively. For comparison, life-cycle water use for refined products from conventional oil is one to three barrels of water per barrel of oil, and corn ethanol can require up to 550 barrels per barrel of oil equivalent.[43]

FIGURE 4

**Oil sands extraction water intensity**

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Note: Brackish water is defined as ground water with dissolved solids exceeding 4,000 milligrams per liter.

*Water demands do vary across oil sands mining operations. Industry wide, in 2012 mining operations used 3.15 barrels of "new" water per barrel of bitumen. And according to data from 2011, when all water sources are considered such as site runoff, river water withdrawals averaged 2.11 barrels per barrel of bitumen. Source: Alberta ESRD, Oil Sands Portal, *Oil Sands Operators: Water Use History,* http://environment.alberta.ca/apps/OSIPDL/Dataset/Details/56#. Athabasca river withdrawals provided directly by Alberta ESRD.

**Industrywide in-situ operations used on average 0.31 barrels of nonsaline groundwater and 0.25 barrels of brackish grounder water per barrel of bitumen produced. Source: Alberta ESRD, Oil Sands.

Source: IHS CERA and Alberta ESRD



### *What are the major sources of water?*

For mining projects, the extraction process requires high-quality fresh water. The Athabasca River—the largest source of fresh water near the mining area—is the main source of water, providing about three of

41. For more information on Syncrude's and Suncor's wetland pilots, see *www.cosia.ca/projects/land/building-fens* and *www.suncor.com/en/newsroom/2418.aspx?id=1805639*, accessed 24 September 2013.

42. Comparison between water barrel and oil barrel is done on an equivalent volumetric basis, where one barrel is equivalent to 0.159 cubic meters.

43. Comparison is on a barrel of oil equivalent energy basis and a net water basis. Sources: Alberta ESRD and US Department of Energy, *Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water*, December 2006.

the four barrels of new water required per barrel of bitumen. The Athabasca River originates from the base of the Columbia Glacier in the Canadian Rockies, where it travels northeast through the oil sands region before terminating in Lake Athabasca in the northeast corner of Alberta. The remainder (about one barrel) comes from rain and other surface runoff that is collected from the mine lease area and some groundwater.

In-situ operations can use lower-quality water, and projects can be located farther from surface water sources. Accordingly, these projects use primarily groundwater. In 2012 nearly half of groundwater withdrawals to support in-situ production were of brackish water, with the remainder made up of higher quality nonsaline water.[44] Nonsaline groundwater may or may not be potable water, is typically found closer to the surface, and is higher quality than brackish sources. All brackish water is nonpotable water and is typically found beneath nonsaline water levels. Because of the depth where brackish water is found, withdrawals are less likely to have a direct impact on the water table and on surface water levels.

### *Water for mining operations (from the Athabasca River)*

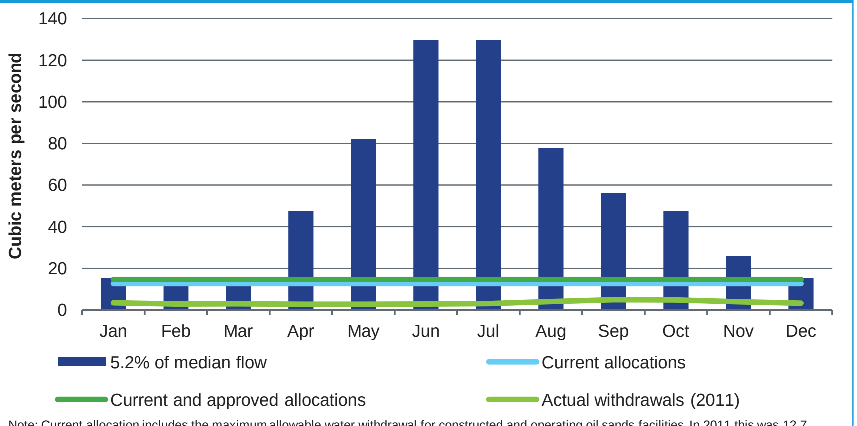
The Athabasca River is the second largest river in Alberta, and its watershed occupies nearly one-quarter of the province—an area of about 58,000 sq mi.[45] In 2011 oil sands mining operations withdrew 1.9 mbd (300,000 cubic meters per day) of water directly from the Athabasca River and an additional 640,000 barrels (102,000 cubic meters per day) from the surrounding environment.[46]

The Athabasca River flow fluctuates seasonally, with higher water levels in the summer and lower water levels in the winter. Water levels in the Athabasca River have been ample to support aquatic life and the wider ecosystem. Yet, given the level of growth expected from mining operations in the coming years, there are concerns that future withdrawals could impact the river's ecosystem, particularly in the winter months.

To protect the river during low-flow periods, the governments of Canada and Alberta have instituted a joint water-use framework. The first phase of this framework limits cumulative withdrawals from the river by oil sands operators to no more than 5.2% of the river's historical monthly median flow. These restrictions are shown in Figure 5—a graph of various withdrawal limits against 5.2% of the historical median flow of the Athabasca River. Current and approved oil sands water withdrawal licenses are near limits in the winter months; however, actual withdrawals have been much lower.[47]

FIGURE 5

**Athabasca River flow: 5.2% of median flow compared to allocated withdrawals**




Note: Current allocation includes the maximum allowable water withdrawal for constructed and operating oil sands facilities. In 2011 this was 12.7 cubic meters per second of the historical median flow. Current and approved allocations include all oil sands facilities currently built and operating as well as approved facilities that may not be in operation yet. In 2011, this was 14.6 cubic meters per second. Actual withdrawals averaged about 3.5 cubic meters per second in 2011.
Source: IHS CERA and Alberta ESRD, 2013 (2011 data)



44. Nonsaline water contains less than 4,000 milligrams (mg) per liter of total dissolved solids, whereas Health Canada defines potable water as containing less than 500 mg per liter of total dissolved solids. In brackish water, total dissolved solids exceed 4,000 mg per liter. For more information on in-situ water use, see Figure 3 footnotes.

45. Source: Athabasca Watershed Council, *www.awc-wpac.ca/content/athabasca-watershed*, accessed 31 July 2013.

46. Source: Athabasca River withdrawals provided by Alberta ESRD. Other water use data from Alberta ESRD Oil Sands Information Portal, *environment.alberta.ca/apps/OSIPDL/Browser#Category=WATER*, accessed 23 July 2013.

47. For more information see Figure 5 footnotes.

Outside of the official joint water-use framework, oil sands producers have implemented a private, nonbinding agreement to manage withdrawals from the Athabasca River during low-flow periods. The arrangement, the Oil Sands Water Management Agreement (OSWMA), currently includes the potential for further reductions—equivalent to less than 3% of the river's historical median flow during low-flow months.[48]

Looking ahead, there are concerns that the current restrictions may not be sufficient to protect the aquatic environment. A group of stakeholders, including representatives from government, industry, environmental groups, and First Nations, made recommendations for a second phase of the joint water-use framework that would reduce the cumulative water withdrawal limit.[49] This second phase of the framework was expected from regulators in 2012 but is yet to be released for public consultation prior to implementation.

Even under the most stringent restrictions, IHS CERA believes that—through the deployment of new technology and practices—water supply will be sufficient to support planned oil sands mining growth. If water withdrawals are more limited in the winter, there are alternatives. For example, new oil sands mining operations (and some older ones) have constructed large holding ponds that enable them to rely on stored water during low-flow winter months. Fluid tailings waste from mining operations is another potential water source. More rapid reclamation of liquid tailings (the potential of which is discussed in the waste section, below) would allow greater recycling of water within mining operations, reducing demands for new water.

### *Water for in-situ operations (groundwater)*

The use of groundwater by in-situ oil sands projects will rise as bitumen output from these operations increases. Assuming no changes in in-situ water use, demand would nearly triple by 2030.[50] However, this outlook is not inevitable. There is potential for in-situ water intensity (particularly for nonsaline water) to decline as the industry moves toward greater use of brackish water sources.

- **Regulations that encourage in-situ projects to recycle more water and shift toward more brackish water sources**. Alberta recently introduced new regulations that will support greater recycling and encourage existing operations to shift toward more brackish water sources.[51] Brackish water sources in Alberta are believed to be immense, though less is known about them because they have had few historical uses and are typically present at greater depths. Importantly, use of brackish water does not compete with other water uses.

- **Potential use of tailings water and other recycled sources**. Although the applications are limited to in-situ operations near mining tailings ponds or local municipal waste systems, both could provide an additional source of recycled water that could reduce new water withdrawals. If more tailings from

48. Under certain low-flow conditions the OSWMA includes the potential for water withdrawal restrictions down to 8.2 cubic meters per second, versus 15 cubic meters per second under the existing framework. Fifteen cubic meters per second is equivalent to 5.2% of historical median flow during low-flow (winter) months. Source: Alberta ESRD, Oil Sands Information Portal, "Oil Sands Mining Management Agreement for 2012–2013 Winter Period," *environment.gov.ab.ca/info/library/8742.pdf*, accessed 16 July 2013.

49. Historical median flow of the Athabasca River during low-flow periods is about 300 cubic meters per second. Under the existing framework, withdrawals are restricted to 15 cubic meters per second when flows fall below 15% of the historical median flow (45 cubic meters per second). Under the recommended phase two framework, restriction could commence at 270 cubic meters per second, ratcheting down to 4.4 cubic meters per second when flow is below 87 cubic meters per second. Sources: Alberta ESRD, and the Cumulative Environmental Management Association (CEMA), *cemaonline.ca/index.php/administration/cat_view/2-communications/44-p2wmf*, accessed 14 October 2013.

50. Forecast groundwater demand growth assumes no new regulations or intensity improvements with a fixed water intensity based on 2012 oil sands production and water withdrawals. Under these restrictive assumptions, annual demand for new (brackish and nonsaline) would grow from 32.6 million cubic meters in 2012 to 93 million cubic meters in 2030. Note that there can be a larger variation in water intensity between projects owing to geology and hydrology. Source of withdrawals: Alberta ESRD. *Oil Sands Operators: Water Use History, All in-situ and integrated in-situ,* http://environment.ca/apps/OSIPDL/Dataset/Details/56, accessed 18 October 2013.

51. Alberta Energy Regulator (2012), Directive 081 - Water Disposal Limits and Reporting Requirements for Thermal In-Situ Oil Sands Schemes, November 21, 2012, *www.aer.ca/rules-and-regulations/directives/directive-081*, accessed 16 July 2013.

mining operations are reclaimed, this could be a large source of water for in-situ projects. Suncor is already making use of water from tailings ponds to augment water demands at one of its in-situ facilities.[52] Some in-situ project operators are also considering the use of municipal wastewater streams.

- **Development of new, less water-intensive in-situ techniques**. New in-situ extraction and water treatment technologies could reduce the demand for new water by further reducing water intensity and improving recycle rates. For instance, increased use of solvents in place of water improves water intensity. Broader deployment of technology, such as combining evaporators with zero liquid discharge processes, could further reduce water intensity by 80% to 100% compared with the traditional technology.[53]

The LARP, discussed in Part 3, will set forth cumulative interim triggers and limits for groundwater quality in the oil sands areas. To support these future requirements, Alberta is conducting a survey of nonsaline groundwater. These efforts will help ensure that industry demand are sustainable.

## Waste (tailings)

Fluid waste material produced from oil sands mining operations, known as tailings, can be hazardous to the environment. While in-situ operations also generate waste, this is less of a concern than the tailings generated by mining operations. Ever since mining operations began, tailings material has been accumulating. Below we explore how tailings material could impact the environment and what is being done to manage further accumulations.

### *What are tailings, and how could they impact the environment?*

Tailings are stored in large open-air settling basins, called tailings ponds. The ponds contain three layers: a top layer of water with some residual bitumen; a middle layer of fluid fine tailings (a combination of clay, silt, and water that does not readily settle); and a bottom layer of coarse sand.[54] Even after years of settling, the middle or fluid fine tailings layer does not settle and is the consistency of pudding. Historically for every barrel of bitumen produced at a mine, about four barrels of tailings were produced that had to be stored on site, with about 1 to 1.5 barrels being fluid fine tailings.[55] As oil sands production has grown, so has the accumulation of tailings. At the end of 2011, tailings ponds contained almost 5.7 billion barrels (900 million cubic meters) of material and covered a collective area about 78 sq mi (200 sq km) or about the size of the District of Columbia.[56]

There are two main environmental concerns about tailings growth: impacts on wildlife, specifically waterfowl if they contact tailings; and impacts if liquid tailings material escapes into the surrounding environment:

- **Impact on waterfowl**. Even though bitumen is periodically skimmed off the surface of tailings ponds, it can nonetheless accumulate (mostly along the edges of the ponds). If waterfowl land on the ponds and come in contact with bitumen, they can become soiled, which can lead to hypothermia or drowning. Although most landings (more than 99%) result in no measurable health impact on the birds, mortalities

52. Suncor Energy Inc., sustainability.suncor.com/2011/en/responsible/1799.aspx, accessed 23 July 2013.
53. See the IHS CERA Special Report *Oil Sands Technology: Past, Present, and Future*.
54. Fluid tailings contain about 1% to 3% bitumen by weight.
55. Fluid fine tailings estimate assumes 30% solids per barrel of bitumen produced and can vary with specific composition of oil sands ore, which can vary across deposits—some have more or less bitumen or fine content.
56. Source: Alberta ESRD. The tailings pond areas are contained within the total area disturbed to date shown in Figure 2.

occur, as was the case in 2008, when 1,600 ducks died, and in 2010, when 230 ducks died.[57] The best strategy is therefore to prevent contact. Since 1999 all mines have been required to have a Waterfowl Protection Plan that includes deterrents, such as air cannons, scarecrows, and flares. In addition, after the 2008 incident the federal and Alberta provincial governments initiated a regional bird monitoring program, and the fines levied against the industry for the death of birds in 2008 was used to finance further research at the University of Alberta. Research at the university and elsewhere is expanding the understanding and techniques of waterfowl protection in the oil sands regions.[58] For example, radar detection systems are being deployed that are expected to improve the effectiveness of bird deterrents.[59]

- **Impacts to the surrounding environment**. Water deposited in the tailings ponds has been found to be toxic to fish and other microorganisms. Although the toxicity of these ponds will decline over time as the organic compounds degrade, this is a slow process. For these reasons the Alberta government does not permit the release of tailings material. Since tailings ponds are unlined earthen structures, there are concerns about seepage of tailings material into the environment. In an effort to prevent this, tailings ponds are generally constructed above grade, above the surrounding land, with secondary containment structures and drains and ditches to collect seepage and surface runoff.[60] Clays found at the bottom of tailings ponds have low hydraulic conductivity and do not easily allow water to pass through, minimizing groundwater seepage. Despite these measures, some water seeps through into the environment. Measuring seepage is difficult, and there are no publicly available data that quantify the volume. Alberta ESRD monitors groundwater quality in the oil sands mining region, requiring each operator to provide an annual groundwater monitoring report. And, according to the “Latest Data” from the Canada-Alberta Oil Sands Environmental Monitoring Information Portal, “low levels of oil sands development-related contaminants” have been found in the water, but “are not a cause of concern.”[61] The joint Canada-Alberta monitoring program, discussed in Part 3, will increase the scale and scope of water monitoring (ground and surface) in these areas.[62]

### *What is being done to address tailings growth and the existing stock of tailings?*

In 2009, the Alberta regulator introduced Directive 74 to slow the accumulation of tailings material after 2010.[63] Although oil sands operators have invested more than C$1 billion in technology to reduce tailings, they did not meet the timeline set by the regulator.[64] Based on our analysis of the development plans outlined by operators, IHS CERA expects the accumulation of tailings to reach around 6.3 billion barrels (1 billion cubic meters) in the next few years (see Figure 6). If further mining operations proceed, the tailings volume could climb higher in the absence of new tailings management regulations. However, if the targets

57. Observed landings from April to October on about 10% of the ponds recorded 20,540 landings and found 139 dead birds. Source: News article in July 12, 2013 issue of the Edmonton Journal, *www.edmontonjournal.com/business/energy-resources/cannons+scaring+birds+away+from+tailings/8649164/story.html?__lsa=afac-1b0f*, accessed 19 July 2013. Source of 2008 bird incident: Reuters (2010), “UPDATE 2-Syncrude Canada fined C$3 [million] for 1,600 duck deaths,” *www.reuters.com/article/2010/10/22/syncrude-ducks-idUSN2219038320101022*, accessed July 15, 2013. Source for 2010 bird incident: Reuters (2010), “At least 230 ducks die in latest Syncrude incident,” *www.reuters.com/article/2010/10/27/us-syncrude-ducks-idUSTRE69L4K620101027*, accessed July 15, 2013.

58. For more information on the Research on Avian Protection Program at the University of Alberta or the Regional Bird Monitoring Program, see *hocking.biology.ualberta.ca/oilsands/?Page=8524*, accessed 14 October 2013.

59. For more information, see Nohara, T. J., Beason, R. C., and Clifford. S. P., (2012), “The Role of Radar-Activated Waterfowl Deterrents on Tailings Ponds,” Presented at the International Oil Sands Tailings Conference, Edmonton, Alberta, December 2012, *www.accipiterradar.com/media/pdf/20120913_Iostc_Noharabeasoncliffordfinal_Distrib_.pdf*, accessed 16 September 2013.

60. Some tailings are stored below grade in mined-out pits.

61. Joint Oil Sands Monitoring, Latest Data, October 10, 2013, www.jointoilsandsmonitoring.ca/pages/latestdata.aspx?lang=en, accessed 15 October 2013.

62. For more information, see Canada-Alberta Oil Sands Environmental Monitoring Information Portal, *www.jointoilsandsmonitoring.ca/pages/home.aspx?lang=en*, accessed 23 July 2013.

63. For more information on Alberta Energy Regulator (formerly ERCB) Directive 74, see http://www.aer.ca/rules-and-regulations/directives/directive-074, accessed 14 October 2013.

64. The regulator in Alberta recently reviewed oil sands tailings performance and determined that although the pace of progress was slower than hoped, the target was “optimistic” and “industry had committed significant resources” toward the issue and “made material progress.” Sources: Alberta Energy Regulator (2012), “2012 Tailings Management Assessment Report: Oil Sands Mining Industry,” *www.aer.ca/documents/oilsands/tailings-plans/tailingsmanagementassessmentreport2011-2012.pdf*, accessed 16 July 2013; Oil Sands Today (CAPP website), *www.oilsandstoday.ca/topics/Tailings/Pages/default.aspx*, accessed 16 July 2013.

are reached, tailings would be processed as the same rate as they are produced, and fluid fine tailings would no longer accumulate.

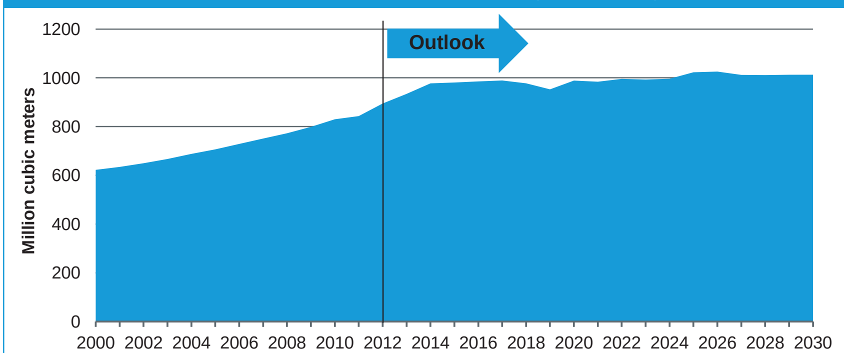
In addition to reducing the rate of accumulation, there is additional focus on reducing the existing tailings inventory. Alberta has committed to reducing legacy tailings material and has promised a new tailings management plan.[65] It will be challenging for the industry to dispose of the tailings. Separating the water from some of the fine clays in the tailings is difficult. Two general methods for disposal are being developed:

- **Liberating water from the tailings**. One disposal method is to allow the tailings to dry out. Areas where tailings have been dried could then support revegetation and reclamation. Tailings do not readily dry out on their own, however, and industry, government, and academia are collaborating on the advancement of technologies to accelerate the separation of water and the drying of tailings.[66] Some leading technologies are centrifuge, atmospheric fines drying, accelerated dewatering, and soft tailings reclamation.[67]

- **Permanently storing the tailings.** Another disposal method is to store the tailings beneath a fresh water cap in end pit lakes (EPLs). The fresh water acts as a barrier between the tailings material beneath and the environment above. Although capping tailings with fresh water has been used in other types of mining operations for decades, in the oil sands it remains unproven. There is concern about whether these lakes can become active ecosystems that support plant and animal life. If unsuccessful they could pose a long-term liability for the province. Before the government permits the use of EPLs, the industry must demonstrate to the satisfaction of regulators that they are a viable option. To this end, Syncrude Canada has been running test ponds since 1989 and is now scaling up this research to a large-scale demonstration project. Although efforts are increasing, it could still be decades before the results will be fully known.[68]

FIGURE 6

**IHS CERA estimate of cumulative fine fluid tailings inventory**




Based on the tailings plans of operators. Does not include the following potential projects: Total E&P Joslyn North or South Mine; Shell Albian Sands Pierre River Mine; Suncor Energy Voyageur South Expansion, Teck Frontier Mine, and Total/Sinopec, Northern Lights Project. Mines plans included: Horizon Tailings Management Plan, November 2010. Suncor Energy 2011 Mine & Tailings Plan Millenium, North Steepbank Extension and Lease 86/17, ERCB Annual Submission, September 2010. Syncrude Annual Tailings Plan Submission Mildred Lake, September 2010. Syncrude Annual Tailings Plan Submission Aurora North, September 2010. Syncrude Annual Tailings Plan Submission Aurora South, September 2010 with a delay from 2016 start to 2021 based on news from Syncrude that project postponed to post 2020. Shell Canada Energy Muskeg River Mine Annual Tailings Management Plan 2011. Shell Albian Sands – Jackpine Mine ERCB Directive 074 Jackpine Mine Tailings Management Plan, December 2010. Imperial Kearl Oil Sands 2010 Annual Tailings Plan Submission to ERCB, September 2010. Fort Hills Energy ERCB Directive 074 Annual Tailings Management Plan, September 2009.
Source: IHS CERA



65. Source of tailings management framework: Lower Athabasca Regional Plan, Tailings Management Framework, *https://landuse.alberta.ca/RegionalPlans/LowerAthabascaRegion/Pages/default.aspx*, accessed 1 August 2013.

66. For more information on this collaboration, see *www.cosia.ca/releases/3/158/Tailings-Technology-Roadmap-project-invokes-major-industry-government-collaboration/d,detail_interior*.

67. For more information, see www.cosia.ca/projects/tailings/tailings-technology-roadmap, accessed 14 October 2013.

68. Source: Syncrude Sustainability Report 2010/11, www.syncrudesustainability.com/2011/environment#operational_environment_tailings-management, accessed 17 September 2013.

# Part 5: Greenhouse gas emissions

GHG emissions linked to oil sands production are a contentious—and high-profile—issue. This section examines the GHG intensity of oil sands compared with other crudes, the aggregate emissions from the industry as a whole, and the state of GHG regulation in the oil sands. It also presents a snapshot of the current state of play and explains how the GHG intensity of oil sands production is expected to decline through the deployment of new technology. The potential impact of the new technology is discussed in Part 6.

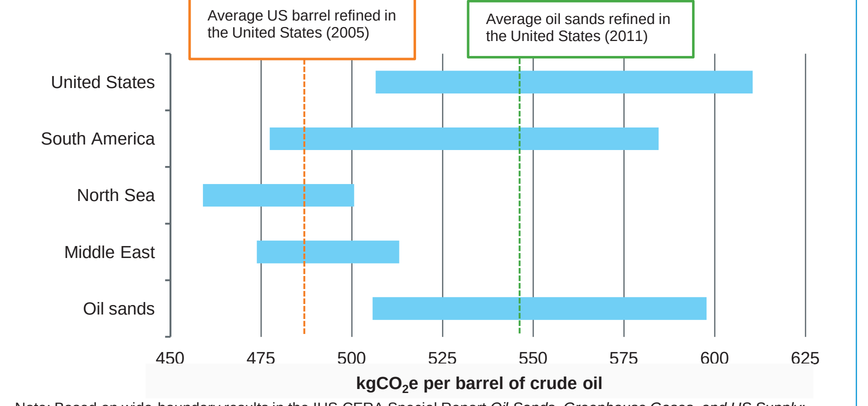
## Why does the GHG intensity of oil sands matter?

Government policy that makes use of crude oil GHG intensities could affect demand for different crudes. Low carbon fuels standards (LCFS) being advanced in British Columbia, California, and the European Union seek to reduce GHG emissions from the entire life cycle of a fuel used within their jurisdiction. This includes GHG emissions from production, processing, transportation, and finally combustion. When LCFS policies differentiate crudes by GHG intensity, oil sands along with other higher carbon crudes can be disadvantaged.

Although oil sands are among the more GHG-intensive crudes, they are not the most intensive—nor are they as high carbon as many commonly cited estimates. On a wells-to-wheels basis—accounting for emissions produced during crude oil extraction, processing, distribution, and combustion, including from upstream fuel consumed in crude production and processing facilities—the GHG emissions from oil sands are 4% to 23% higher than from the average crude consumed in the United States, using a 2005 baseline. For the average oil sands product actually exported to the United States, life-cycle GHG emissions are only 12% higher. As shown in Figure 7, sources of supply from other oil-producing regions are in the same range as oil sands.[69] For example, the GHG emissions of Venezuelan crude, the most likely alternative to oil sands in the USGC, are in the same range as oil sands (4–20% higher than the average crude refined in the United States).[70]

FIGURE 7

**Well-to-wheels greenhouse gas intensity from major areas of US supply**




Note: Based on wide-boundary results in the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Supply: Getting the Numbers Right—2012 Update*.
Crude ranges based specifically on United States: Mars to Midway-Sunset; South America: Brazil Tupi to Venezuela Petrozuata; North Sea: Statfjord to Mariner; Middle East: Arab Medium to Basra Light; and oil sands: mining dilbit to SAGD SCO.
Source: IHS CERA



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69. For more information, see the IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update*.

70. Venezuela produces a number of crude oil blends that are imported into the Unites States. Similar to oil sands, the GHG intensity of Venezuelan crudes differs depending on the specific blend. For example our estimate of the GHG intensity of Bachaquero, a conventional Venezuelan heavy crude, is 4% higher than the average crude refined in the United States. However, if Venezuela were to grow production it would mostly likely come from the Orinoco belt. We estimate that the GHG intensities for upgraded Orinoco production, Petrozuata and Zuata Sweet, are 20% and 15% higher, respectively. For more information on alternative crudes oil to Canadian oil sands in the USGC, see the IHS CERA Insight *Keystone XL Pipeline: No material impact on US GHG emissions*.

 

Measuring the life-cycle GHG emissions of fuels is complex. Data quality and availability are often a key challenge—making estimates of crude oil emissions less certain. In a 2011 report, IHS CERA compared the availability of environmental data from eight existing and potential future crude oil suppliers to the United States: Canada, Mexico, Saudi Arabia, Nigeria, Venezuela, Iraq, Brazil, and Kazakhstan. We found that of all the jurisdictions compared, the Canadian oil sands have the highest level of readily available online data.[71] Since Canada provides more data than most other crude suppliers, there is a risk that oil sands could be unfairly disadvantaged compared with other supply sources.

## Aggregate GHG emissions: Current and outlook

Aggregate oil sands emissions are growing alongside production growth. In 2011 oil sands operations emitted 55 million metric tons (MMt) of carbon dioxide equivalent ($CO_2$e) per year—7.8% of Canada's total GHG emissions and 0.14% of global emissions.[72] This is on a similar scale as the level of emissions from power generation from the states of Louisiana or Arizona in 2011.[73] Assuming that no new climate change policies are implemented in Canada, Environment Canada estimates oil sands emissions could reach 104 MMt$CO_2$e per year by 2020. This could make oil sands responsible for 14% of Canada's total emissions.[74]

## GHG Regulations

Oil sands GHG emissions are regulated at the provincial level. Since 2007 oil sands facilities and other large emitters in Alberta have been required to reduce emissions intensity by 2% per year, ramping up to 12% below an average intensity baseline established over the first three years of operation, or from 2003 to 2005 for existing facilities.[75] To comply, operators have the option of reducing emissions, investing in offsets, or paying a carbon levy of C$15 per ton for every ton of GHG emissions produced above the limit. Since 2007, over C$300 million has been collected by the provincial government from the carbon levy. These funds are reinvested in projects geared toward reducing GHG emissions.[76] In total, Alberta estimates that operational changes and investment in offsets as a result of their program have contributed to 40 MMt in GHG reductions from 2007 to 2012.[77]

The federal government is developing additional regulations. At the UN Climate Change Conference in Copenhagen in 2009, Canada committed to reducing its total GHG emissions by 17% from 2005 levels by 2020—the same objective as the United States. To meet this goal Canada is adopting a sector-by-sector approach to GHG reductions.[78] In 2012 Canada finalized regulations for the coal-fired power generation sector and is now developing regulations for the oil and gas sector, including for the oil sands.

71. See the IHS CERA Special Report *Major Sources of US Oil Supply: The Challenge of Comparisons*.

72. Estimate of global share of emissions based on oil sands' share of Canadian emissions on a $CO_2$ equivalent basis in 2011 and Canada's share of global emissions on a $CO_2$ basis from combustion in 2010. Source: Environment Canada (2013), *National Inventory Report 1990–2011*, 15 April 2013, *unfcc.int/national_reports/annex_i_ghg_inventories_submissions/items/7383.php*, accessed 16 July 2013; Source: International Energy Agency (2012), CO2 *Emissions from Fuel Combustion Highlights*, *www.iea.org/co2highlights/co2highlights.pdf*, accessed 16 September 2013.

73. Source: 2011 US Environmental Protection Agency, *Greenhouse Gas Emissions from Large Facilities*, *http://ghgdata.epa.gov/ghgp*, accessed 16 September 2013.

74. Source: Environment Canada (2012), *Canada's Emissions Trends*, August 2012.

75. In 2007 the Specified Gas Emitters Regulation came into force in Alberta. It covers large stationary sources of GHG emissions, such as power plants, oil and gas facilities, and refineries that emit more than 100,000 metric tons of GHG per year. For more information, see *www.environment.alberta.ca/01838.html*, accessed 14 October 2013.

76. For more information, see Alberta's Climate Change Strategy, *environment.alberta.ca/0909.html*, accessed 23 July 2013.

77. Source: Alberta ESRD, 2012 Greenhouse Gas Emissions Reduction Program Results, *http://environment.alberta.ca/04220.html*, accessed 13 September 2013.

78. The Canadian approach also includes a number of energy efficiency measures, such a renewable fuels standards, light- and heavy-duty vehicle standards, and appliance standards.

# Part 6: Technology

Technical innovation is at the heart of the Canadian oil sands story and is expected to bring about reductions in costs and the environmental intensity of oil sands production.

The deployment of new technology has made the oil sands an economic venture and at the same time has reduced its environmental footprint. (The average GHG intensity of oil sands production is 26% lower than it was in 1990.)[79] Collaboration is another perennial theme in oil sands development, playing a central role in past innovations, including in the development of SAGD. The original SAGD pilot project was conducted in 1984 by Alberta Oil Sands Technology and Research Authority (AOSTRA), a partnership between government and industry. Over AOSTRA's 25-year existence, industry and government have joined forces on 16 oil sands field trials; the SAGD pilot was the only trial that resulted in a commercial process.[80]

## Accelerating innovation and collaboration

Technical innovation continues today, and a wide range of new approaches are under development. In fact, compared with the past, new ideas are being tested at an accelerated pace. Innovations being tested include new in-situ extraction methods (such as using hot or cold solvents, electric heating, or in-situ combustion to mobilize the bitumen) and methods to capture carbon from combustion exhaust streams. One project plans to convert carbon emissions from oil sands into biofuels. Many mining pilots aim to reduce water use and eliminate tailings waste. All together, the industry has plans for over 10 field pilots—more than half the pilots that AOSTRA's accomplished in its 25-year existence. Although there is no certainty that the field pilots will lead to commercial technologies, with such a significant number of ideas being field tested—a critical step in technology development—the chances are greatly improved.

Collaboration is also accelerating. The formation of COSIA was announced in 2012, and as of mid-2013, 14 major oil sands companies had come together to share environmental research, technology, and best practices.

COSIA is arguably the most extensive example of industry collaboration to date. Companies are putting aside their competitive cultures and intellectual property when it comes to environmental technology. There is a shared realization that only by accelerating the development and deployment of environmental improvements are material changes in oil sands operations likely to result. The breadth of COSIA's mandate is wide, and the challenge is great—effectively to enable responsible and sustainable development of the Canadian oil sands. It is focused on four main environmental challenges, all of which we document in this report: tailings management and reduction, water use and improved recycling, reduction of land use and impact, and GHG reduction. Our research was unable to find other examples of collaboration on the scale of COSIA elsewhere in the oil and gas industry.[81]

The rapid sharing of ideas is a clear advantage of the COSIA model. If green techniques are deployed at one oil sands operation, the innovation has little impact on the aggregate environmental footprint of the industry. Only when technologies are applied widely, across a greater volume of production, are material impacts possible. COSIA has the potential to speed up the industrywide deployment of new ideas. The ultimate success of COSIA will take many years to measure, since advancements in oil sands technology are most often measured in decades, not years. However, COSIA's initiatives, combined with numerous other industry collaborations, constitute a major step toward reducing the environmental intensity of oil sands production.

79. Source: Environment Canada, May 2013 National GHG Inventory Report 1990–2011.

80. In 2000 what was AOSTRA became part of Alberta Innovates—Energy and Environmental Solutions.

81. For more information, see *www.cosia.ca*.

 

## Potential for reducing the environmental intensity of oil sands

Over the next decade, the greatest opportunity for oil sands GHG emissions reductions is through adding solvents to the steam used for in-situ recovery—a technique called hybrid steam-solvent extraction. If the technique can be made economic, it could reduce GHG production emissions by 25% or more and lower water use by an even greater margin. Since this technique can be applied to existing facilities, it could have a material impact on aggregate emissions from the industry.

For the more mature mining operations, although some options exist for GHG improvements, such as lower-temperature water extraction methods, compared with in-situ operations there is less potential for a material change in GHG emissions. However, assuming that technologies to dry tailings are developed, there are significant opportunities to reduce water withdrawals. Given the Alberta and Canadian governments' significant investment, we expect at least one oil sands–related carbon capture and storage (CCS) project to be operational within the decade. The project will capture emissions from the oil sands upgrader, reducing the GHG intensity from producing SCO from mining by about 20% compared with current levels.[82]

Longer term, the development of totally new extraction methods could lead to greater reductions in environmental intensity, but these trends are not inevitable. Even when ideas are found to be commercially viable, the time lag between a successful pilot and broad commercial deployment is typically more than a decade. Further, most completely novel extraction methods can be applied only to new facilities. Consequently, it can take decades before production from these new ideas becomes large enough to have a material impact on the environmental intensity of the industry as a whole.

82. The Quest CCS project is under way at the Scotford Upgrader in Edmonton. The Alberta government is investing C$745 million (from a C$2 billion fund for CCS), and the Government of Canada is investing C$120 million (from the Clean Energy Fund). The project is expected to reduce upgrading emissions by 35%. IHS CERA has estimated that this equates to about a 20% combined reduction from mining and upgrading. For more information, see *www.shell.ca/en/aboutshell/our-business-tpkg/upstream/oil-sands/quest.html*. There is another project with the potential to capture and store $CO_2$ related to oil sands being advanced in Alberta. The North West Upgrader, a refinery planned near Edmonton, will include $CO_2$ capture for use in enhanced oil recovery as well as storage. For more information, see *www.northwestupgrading.com*, accessed 14 October 2013.

# Part 7: Pipeline transport of oil sands

Concern has been expressed that pipelines transporting oil sands crude, specifically diluted bitumen, may be more at risk for spills than those transporting conventional crudes. However, pipeline corrosion is a well understood phenomenon, and a number of scientific studies have found no evidence that oil sands crudes subject pipelines to greater risk of damage or spills than other crudes.[83]

It has been suggested that the characteristics of oil sands crudes, which can have a relatively high total acid number (TAN) and sulfur content, make them more likely than other crudes to corrode pipelines. However, the properties of oil sands crudes have been found to be within the range of other crudes transported by pipeline in North America. Moreover, although these two measures of crude quality are important corrosion indicators under refinery conditions (higher temperatures, higher velocity, and smaller pipes), they are of little relevance under transportation pipeline conditions (lower temperature, lower velocity, and larger pipes). For corrosion to occur in transmission pipelines, water along with a corrosive agent, such as sulfides, must be present and be in sustained contact with the pipeline surface. Yet impurities, such as moisture, sediment, and other chemicals that are known to contribute to corrosion, are tightly controlled in pipeline operations.[84]

The velocity and temperature of crude oil moving in the pipeline are other important factors in preventing pipeline corrosion. Water can separate from crude oil if the velocity of crude oil through a pipeline is insufficient. Pipelines that carry heavy crudes (including diluted bitumen) are operated at rates that prevent water accumulation. Moreover, even if water accumulates for any reason (e.g., an upset in pipeline operations that slows flows), when the crude velocity is restored, water would be reabsorbed.

It has also been suggested that pipelines transmitting oil sands crude can operate at higher temperatures, potentially contributing to pipeline metal fatigue. However, studies have shown that pipelines carrying diluted bitumen typically operate at less than 50° Celsius (C), well below temperatures of concern—over 200°C—and within the range of other pipelines.[85]

83. Sources: Been, J. (2011), "Comparison of the Corrosivity of Dilbit and Conventional Crude," prepared for Alberta Innovates-Technology Futures, September 2011, *http://ai-ees.ca/media/6860/1919_corrosivity_of_dilbit_vs_conventional_crude-nov28-11_rev1.pdf*, accessed 22 July 2013. Papavinasam, S., Rahimi, P., Williamson, S. "Corrosion Conditions in the Path of Bitumen from Well to Wheels," NACE 2012 Northern Area Eastern Conference, Toronto, Canada, October 28–31, 2012, *http://www.nrcan.gc.ca/minerals-metals/materials-technology/4542*, accessed 22 July 2012. Penspen (2013), "State of the Art Report: Dilbit Corrosivity," Commissioned for Canadian Energy Pipeline Association, February 21, 2013, Document No. 12671RPT-001 REV 1 *http://www.cepa.com/wp-content/uploads/2013/02/FINAL-Penspen-Report-Dilbit_Corrosivity_Final.pdf*, accessed 22 July 2013. The National Research Council (2013), "TRB Special Report 311: Effects of Diluted Bitumen on Crude Oil Transmission Pipelines," Washington, DC: The National Academies Press, 2013, *http://www.nap.edu/catalog.php?record_id=18381*, accessed 22 July 2013.

84. Basic sediments, salts, and water are tightly controlled and limited to less than 0.5% on a mass-to-volume basis.

85. Organic acids, as measured by TAN, can be a concern under refinery temperatures above 200°C. For more information see prior footnote with reference to studies.

# Conclusion

For a number of important issues related to oil sands development, a wide spectrum of views exists. These differences are at the heart of the debate over the future of oil sands development and market access. Since we issued our first Special Report on the oil sands in 2009, the heightened level of scrutiny of the oil sands—by environmental nongovernmental organizations, media, academia, governments, and the general public—has contributed to an evolution in government regulation and oversight, as well as industry collaboration.

Key areas of changes are

- **Regulation**. The federal and provincial governments in Canada are implementing a more cumulative approach to oil sands development, establishing regional environmental thresholds.

- **Oversight**. Governments are moving to expand and strengthen monitoring activities, putting more equipment and people on the ground to monitor activities and make data more accessible to the public.

- **Collaborative technology development**. Industry initiatives such as COSIA are encouraging faster technology development by pooling resources and sharing learning, and more pilot programs than ever are now under way. Historically, research has been focused on the economics of extracting oil sands; but today there is a greater focus on the environmental footprint.

These changes are providing greater clarity to some key environmental questions, such as the sustainability of water use; the end of tailings accumulation; and the future of regional air quality. But questions remain. For instance, for mining operations: What will reclaimed land look like? And for in-situ operations: How will industry work to protect key wildlife habitats?

The future of oil sands development is of great importance to Canada and beyond, since it impacts both North American oil security and global crude supply. The far-reaching dialogue surrounding oil sands is shaping future development and helping the industry and government to strike the appropriate balance between meeting economic and security objectives and safeguarding the environment.

## Report participants and reviewers

On 13 November 2012, IHS CERA hosted a focus group meeting in Washington, DC, to providing an opportunity for oil sands stakeholders to convene and discuss perspectives on the critical questions shaping oil sands development. A number of those participants also reviewed a draft version of this report.

Participation in the focus group or in the 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

Alberta Environment and Sustainable Resource Development

Alberta Innovates, Energy and Environmental Solutions

American Petroleum Institute

BP Canada

Canadian Association of Petroleum Producers

Canadian Oil Sands Limited

Cenovus Energy Inc.

Devon Energy Corporation

Enbridge Inc.

Conoco Philips Company

Canadian Natural Resources Ltd.

Imperial Oil Ltd.

In Situ Oil Sands Alliance

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Pembina Institute

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

 

## IHS team

**Jackie Forrest**, Senior Director, leads the North American Crude Oil Markets service with IHS and heads the research effort for the IHS CERA Canadian Oil Sands Energy Dialogue. She actively monitors emerging strategic trends related to the oil sands and heavy oil, including capital projects, economics, policy, environment, and markets. Recent contributions to oil sands research include reports on the life-cycle emissions from crude oil, the impacts of low-carbon fuel standards, effects of US policy on oil sands, and future markets for Canadian oil sands. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**Kevin Birn**, Associate Director, is the principal researcher for the IHS CERA Canadian Oil Sands Energy Dialogue. His recent contributions to oil sands research include analysis of the marine transport of oil sands crude and the future markets for oil sands. Prior to joining IHS CERA Mr. Birn worked for the Government of Canada and was for a time senior oil sands economist at Natural Resources Canada, influential is setting early federal oil sands policy. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US Secretary of Energy. Mr. Birn holds an undergraduate degree in business and a graduate degree in economics from the University of Alberta.

**Jeff Meyer**, Associate Director, 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.

# Extracting Economic Value from the Canadian Oil Sands

## Upgrading and refining in Alberta (or not)?

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## About this report

**Purpose.** For the first years of Canadian oil sands development, all projects upgraded their heavy crude to light products before pipelining them to market. Today most new oil sands projects are opting to send the heavy crude directly to market—without upgrading or refining it locally. What are the economic drivers shaping the decision to process bitumen or not? What option uses capital most efficiently, and how does the decision to process bitumen locally (or not) affect Alberta and Canada more broadly—for instance impacting jobs, government revenues, and greenhouse gas (GHG) emissions.

**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.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** This report includes multistakeholder input from a focus group meeting held in Calgary, Alberta, on 7 June 2012 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 end of report for a list of participants and the IHS CERA team).

**Structure.** This report has four sections.

- Part 1: Introduction
- Part 2: The economics for upgrading and refining oil sands
- Part 3: Implications—Production, jobs, government revenues, and GHG emissions
- Part 4: Conclusion

# EXTRACTING ECONOMIC VALUE FROM THE CANADIAN OIL SANDS: UPGRADING AND REFINING IN ALBERTA (OR NOT)?

## KEY IMPLICATIONS

In the earlier years of Canadian oil sands development, all projects upgraded their heavy crude to light products before shipping them to market. Today, most new oil sands projects are opting to send the heavy crude directly to market—without upgrading or refining in Alberta. This has spurred a debate about the role of value-added upgrading and refining in the Alberta oil industry. Specifically, the debate is about what role, if any, policy should play in shaping investment decisions about upgrading and refining.

- **Alberta greenfield upgrading economics are challenged by an outlook for a narrow price difference between light and heavy crudes and high construction costs.** Both factors discourage investment in upgrading equipment.

- **Owing to challenging economics, we expect a future with less greenfield upgrading investment in Alberta. Less upgrader construction has benefits, since it reduces the strain on an already tight labor market.** In a case where the region's limited pool of construction workers is deployed on bitumen-producing projects instead of upgraders or refineries, this drives production higher, resulting in more jobs and economic benefits to Alberta and Canada.

- **Instead of building new upgraders or refineries, modifying existing refining capacity to process oil sands is the most economic way to add processing capacity.** When comparing a greenfield project to modifying an existing refinery, modification is more economic. However, refinery conversion projects still face challenging market conditions in North America. With ample supplies of light crude in some regions, refiners have little motivation to undertake costly investments aimed at converting refineries to consume heavy crude.

- **For a greenfield refinery project focused on oil sands processing, the strongest investment return is in Asia, where oil demand is growing. Although the potential is not as strong as in Asia, under the right conditions the economics of new refinery projects in Alberta and British Columbia could work.** Asia's advantage is primarily the result of lower project costs (building a comparable project in China is at least 30% cheaper than in North America). For Alberta and British Columbia—assuming that a new refinery project consumes bitumen, manages to keep capital costs to a minimum, maximizes diesel production, and does not oversupply its market—the economics could work.

—March 2013


55 Cambridge Parkway, Cambridge, Massachusetts 02142

# EXTRACTING ECONOMIC VALUE FROM THE CANADIAN OIL SANDS: UPGRADING AND REFINING IN ALBERTA (OR NOT)?

## PART 1: INTRODUCTION

To upgrade or not? This is a perennial question facing producers of Canadian oil sands. Bitumen—the raw material produced from oil sands—is an extra-heavy crude oil that needs significant processing to turn into valuable refined products such as diesel and gasoline. Oil sands producers face two options when it comes to the upgrading question. One option is not to upgrade and instead to blend the bitumen with condensate so that it can be shipped via pipeline to refineries with heavy conversion capacity. These are refineries capable of processing extra-heavy crude oil—such as bitumen blended with condensate—into light refined products. The second option is to upgrade the bitumen into a synthetic light crude oil (SCO). SCO can be processed by refineries that lack conversion capacity, which makes it marketable to a broader refining market compared with bitumen blend.

Prior to the onset of the global recession in 2008, the outlook for value-added upgrading and refining in the Canadian oil sands was bullish. Five upgraders were under construction, while six other upgrading projects plus two refining projects were in the earlier stages of development.* A key motivation for upgrading bitumen at that time was that the resulting SCO fetched a much higher price than bitumen blend. Altogether, the projects proposed before the recession represented well over $100 billion in direct capital investment and about 3 million barrels per day (mbd) of upgrading and refining capacity.

Five years later, this outlook has been turned on its head. Only three of the five upgraders under construction in 2008 were completed, and the remaining projects were canceled or put on hold, leaving behind a landscape of partially erected towers. Today, while some projects are advancing, many were canceled.** Most future oil sands supply will be heavy crude that will be sent directly to market—without upgrading or refining locally. What happened to value-added upgrading and refining in Alberta, and what are the implications of oil sands processing for Alberta and Canada?

This report has four parts:

- Part 1: Introduction
- Part 2: The economics for upgrading and refining oil sands

*Refining and upgrading projects and status in 2008: CNRL Horizon phase 1 (construction) plus future phases (approved and announced); OPTI/Nexen Long Lake Phase 1 (construction) plus future phases (approved and application); Suncor Voyageur Phase 1 (construction) plus future phase (approved); Syncrude Mildred Lake debottleneck and expansion (announced); Athabasca Oil Sands Project (AOSP) Scotford 1 Expansion (construction); BA Energy/Value Creation phase 1 (construction) plus future phases (approved); North West Upgrader/refinery (approved); Petro-Canada Fort Hills (approved); Shell Scotford 2 (application); Statoil upgrader (application); Total E&P Northern Lights (application); Peace River Oil BlueSky Refining (announced); Husky Energy- Lloydminster upgrader expansion (announced).
**Projects under construction in 2008 that were completed include CNRL Horizon, OPTI/Nexen, and Albian Oil Sands Scotford 1 Expansion. Projects under construction in 2008 that were canceled or put on hold include Suncor's Voyageur (on hold with a decision expected soon) and BA Energy/Value Creation (canceled). Projects currently advancing include North West Redwater Partnership refinery and Kitimat Clean Refinery.

- Part 3: Implications—Production, jobs, government revenues, and greenhouse gas (GHG) emissions
- Part 4: Conclusion

Throughout this report, we refer to various crude oil terms. See the box "Primer: Crude oil terms" for definitions.

**Primer: Crude oil terms**

**CANADIAN OIL SANDS**

In its natural state, raw bitumen is solid at room temperature and cannot be transported in pipelines. For transport, bitumen must be either diluted with light oil into a bitumen blend or converted into a light crude oil—called synthetic crude oil (SCO).

- **Synthetic crude oil.** SCO is produced from bitumen via refinery conversion units called upgraders that turn heavy hydrocarbons into lighter, more valuable components from which gasoline and diesel are manufactured. SCO resembles light, sweet crude oil, with API gravity typically greater than 30°.
- **Bitumen blend and dilbit.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons. A refinery may need modifications to process large amounts of bitumen blends because they result in more heavy oil products than most crude oils. Bitumen blends typically have a gravity of 22°API (similar to other heavy crude oils such as Mexican Maya). The most common bitumen blend involves diluting bitumen with a natural gas condensate to make a substance called dilbit. A typical blend is about 72% bitumen and 28% condensate.

# PART 2: THE ECONOMICS FOR UPGRADING AND REFINING OIL SANDS

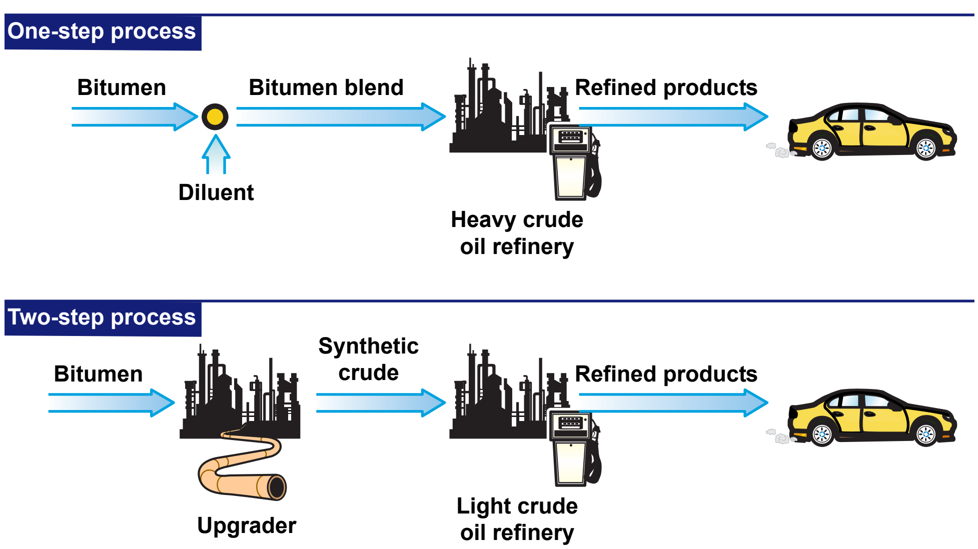
In 2012 Canadian oil sands production was about 1.8 mbd. By 2020 output is expected to reach 3.2 mbd. Today most of the growth is anticipated to be heavy crude supply—shipped by pipeline to be refined outside of Alberta. This section provides upgrading and refining basics and an explanation of why the prospects for value-added upgrading and refining bitumen have dimmed since 2008. Finally, it compares the economics for processing bitumen in Alberta with those of other locations.

## ECONOMIC BASICS: UPGRADING AND REFINING OIL SANDS BITUMEN

When first extracted, the bitumen from the oil sands is the consistency of peanut butter. Like other crudes, bitumen must be converted to gasoline or diesel or some other product before it can be consumed. The transformation can take place in a two-step process (upgrading to a light, sweet crude called SCO in one location and refining into transportation fuels in another) or in a single step (refining the bitumen directly into transportation fuels). Prior to the global recession, the two-step process was the dominant strategy deployed in the Canadian oil sands (see Figure 1). Although not the only factor, technical limitations were one reason for the historical dominance of the two-step process.*

**Figure 1**

**Bitumen upgrading and refining: One-step and two-step processes**




Source: IHS CERA.
21211-1

*In the early years of oil sands development (when commercial production was limited to surface mining operations), extraction methods required bitumen to be upgraded. However, today, new mining extraction techniques have been developed that enable producers to transport blended bitumen, without upgrading. Production by in-situ extraction, a growing source of oil sands supply, also does not require upgrading prior to shipment to market.

Whether a one- or two-step process is deployed, facilities for converting bitumen into lighter products are capital intensive. New greenfield refineries or upgraders cost many billions of dollars. Once built, the facilities make money on the price difference between the heavy crudes they consume and the light products they produce. The wider the price gap, the more money the facilities make and the faster they can pay back the large upfront capital investment. Conversely, if the spread between heavy crudes and light products becomes too small, profit dwindles, and the payback of the initial capital investment is put at risk.

## CHANGING TIMES FOR UPGRADING AND REFINING IN ALBERTA

Since the 2009 recession, challenging economics have changed the outlook for upgrading and refining in Alberta. The main causes are project costs and the outlook for the price difference between heavy and light crudes.

### Rising capital costs

Cost is a barrier for new upgrading or refining projects in Alberta; when projects were first proposed (in the earlier 2000s), investors expected lower price tags. From 2000 to 2008 (as measured by the IHS CERA Capital Costs Index) costs for building upgraders or refineries in Alberta increased by 70%.* The rate of change was borne out on actual projects built this decade, which had final price tags that were 50% to 100% higher than original estimates. Although costs softened during the recession, they have since recovered and are now higher than pre-recession levels. The situation is not unique to Alberta. Project costs around the globe registered similar escalation owing to increased demand for commodities, equipment, and specialized personnel. However, with absolute costs in Alberta already higher than most other regions, escalation had a more severe impact on project economics in Alberta.**

### Narrow light-heavy crude price differentials

The long-term outlook is for a narrow price differential between light and heavy crudes, and this discourages investment in upgrading equipment.

- **Global light-heavy price differentials.** The recession created a sharp drop in oil demand, and this collapsed light-heavy price differentials. Since the recession, the global price difference has remained narrow. One reason is that heavy oil refining capacity has outstripped available heavy feedstock—causing increased competition for these crudes, higher prices, and a shrinking light-heavy price differential. More recently, another cause of narrow differentials is the rapid growth of light, sweet crude supply in North America.*** With light oil oversupplying some North American regions, light

*As measured in Canadian dollars. Source: IHS CERA North American Crude Oil Markets Service, which tracks and provides outlook for capital costs in oil sands projects.

**Capital costs for Alberta oil sands have historically been higher than those for other regions, owing mostly to higher labor costs, lower labor productivity (stemming from extreme weather conditions), and challenges constructing in a remote landlocked location.

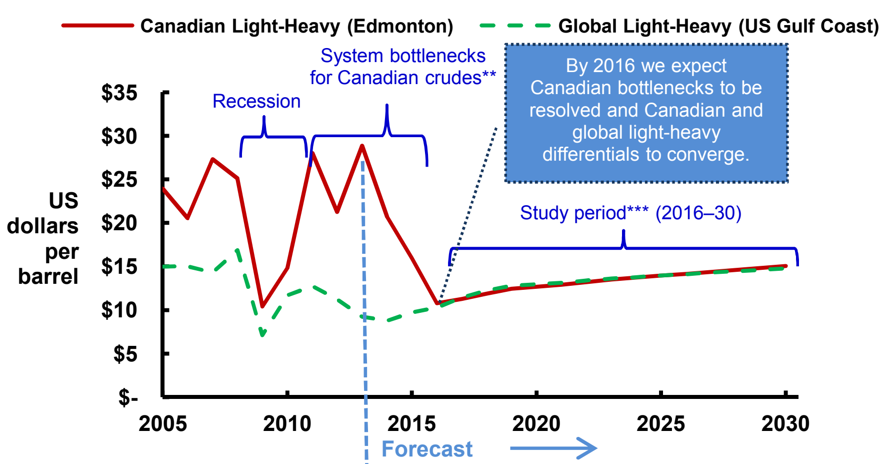
***Since 2011 North American light oil supply has been growing rapidly. The same horizontal hydraulic fracturing technology that unlocked vast reserves of shale gas has been applied to tight oil formations with startling success. Application of this technique is resulting in swift production growth.

crude prices are weak, and this is another factor keeping the price difference between light and heavy crudes narrow.

- **Canadian light-heavy price differentials.** Along with global prices, Canadian light-heavy differentials collapsed during the recession. However, Canadian prices took a different path postrecession. Global light-heavy price differentials remained narrow, while western Canadian differentials widened. The primary cause for the diverging price paths is the rapid growth in North American oil supply. In the past few years both oil sands and tight oil have flooded inland refining markets, with limited outlets to other markets. The flood of oil has resulted in crude price discounts and wide light-heavy price differentials for western Canadian crudes. Although oil supplies are still growing, by 2016 we expect new pipelines will connect rising Canadian supply to new markets. These connections will alleviate the crude oversupply, and Canadian light-heavy price differentials should converge with global ones (see Figure 2).

Critical to our outlook is the assumption that Canadian crudes will have greater access to new markets. Key pipeline projects in our outlook include Flanagan South/Seaway twinning (2014) and Keystone XL (2015–16), both projects connect western Canada to the US Gulf Coast (USGC)—a region with considerable capacity for consuming heavy crude. If either project is delayed, we expect other pipeline projects could be advanced in their place within

**Figure 2**
**Global and Canadian light-heavy price differentials***




Source: Platts, IHS CERA.
Disclaimer: Historial oil price data are extracted or derived by IHS CERA from Platts. All rights reserved. All liability for errors and omissions is hereby excluded by Platts and its sources. No representations or warranties are made by Platts or its sources concerning the data or any conclusions to be drawn from it.
*Canadian light-heavy price differential is the difference between SCO and Cold Lake Blend (a dilbit blend) in Edmonton in constant 2011 dollars. Global light-heavy price differential is the difference between Light Louisana Sweet and Mexican Maya on the USGC in constant 2011 dollars.
**Since 2011 growing supply, pipeline bottlenecks, and refinery disruptions have contributed to price discounts and in temporarily widening the light-heavy differential for oil sands producers. As additional pipeline capacity is brought online over the next few years, these discounts should subside and the differential to narrow by 2016, after which differentials are expected to slowly widen but remain narrower than in the recent past.
***Study range was based on our assessment of the earliest date that a project could be completed and online, given a sanctioning decision today.

the 2014 to 2017 time frame.* In the same way, the alternative projects would ease the wide Canadian light-heavy oil price differentials. If sufficient transport capacity is not built, then prices for Canadian crudes would remain discounted, resulting in wider light-heavy price differentials than would otherwise be the case. However, this situation is not necessarily positive for investment in Alberta. Since the absolute value of all crudes would be depressed (compared with global prices), it may well encourage investment elsewhere.

## UPGRADING AND REFINING ECONOMICS: ALBERTA COMPARED WITH ALTERNATIVE REGIONS

### Scope and purpose

*This analysis is generic and not indicative of any project currently being advanced.*

The purpose of our analysis is to create a generic comparison across the range of potential investments for upgrading and refining of oil sands bitumen to help explain the comparative economics of Alberta with alternative regions as well as why plans for upgrading and refining in Alberta have changed.

While a number of oil sands refining and upgrading projects are advancing, the results of our analysis are not intended to reflect the economics of any actual project. The details of specific projects are proprietary and will vary from our generic examples. Further, integrated oils sands operators may evaluate investment decisions as incremental to an existing asset or as an integrated investment (both upstream and downstream).

The scope of our analysis also does not consider the economics for partial upgrading.** Nor does the scope consider petrochemical investments that could be associated with an upgrader or refinery and the corresponding impact of this investment on project economics.

The following is a summary and status report of the oil sands upgrading and refining projects currently being advanced, and how they differ from the generic assumptions used in our analysis:

- **Voyager upgrader.** The greenfield upgrader is a 200,000 barrels per day (bd) facility to be built in Fort McMurray by Suncor and partner Total E&P. The project was under construction (prior to the recession) and was put on hold during the downturn but restarted in 2011. In November 2012 Suncor announced it was reevaluating the economics of the project. Subsequently, in February 2013, Suncor announced a C$1.5 billion write-down on its investment. A final decision on the project is expected in March 2013. The Voyager project differs from our generic model in that it is built in

*Other projects that could provide additional takeaway capacity include the Enbridge Line 9 full reversal (2014), Enbridge Mainline expansion (2015), TransCanada Eastern Mainline oil pipeline project (2017), and the Kinder Morgan Trans Mountain expansion (2017).

**Partial upgrading is not analogous to the upgrading discussed in this report, and technologies and specific products do vary. In general, the goal of partial upgrading is to upgrade the bitumen just enough to transport. While the product is typically higher quality than a typical bitumen blend, its characteristics are closer to a bitumen blend than the light SCO described in this report. Partial upgrading capital costs and product values are different from those described here, and consequently the results of our analysis do not reflect the economics for partial upgrading.

Fort McMurray, it has the potential to be integrated with upstream operations, and—since some expense has already been incurred—the capital costs should be lower.

- **North West Redwater Partnership Refinery.** In November 2012, North West Upgrading and partner Canadian Natural Resources sanctioned the first phase of construction of a greenfield refinery located outside of Edmonton. The first phase is 50,000 bd, and the facility will convert bitumen into refined products. The cost estimate for phase 1 is C$5.7 billion. Differences between the project and our generic model include size, technology (the facility uses gasification), and refined products yields.

- **Kitimat Clean Refinery.** In August 2012, Kitimat Clean announced that it would submit an Environmental Assessment Application to build an oil sands refinery in Kitimat, British Columbia. The plant would convert bitumen into 390,000 bd of refined products destined for Asia export markets.* Compared with our generic model, the capital cost is lower (cost estimate from the early stages of planning is C$13 billion for 390,000 bd of refined products). One reason for the expectation of lower cost is the plan to deploy very large modules fabricated in Asia for the construction. Other differences from our generic mode include yields of refined products, size, and location (ours does not prescribe to a particular location along the west coast).

## Project types and markets included

Since the upgrading or refining of bitumen can be performed in a variety of geographical locations (in Alberta, in the market the fuel is consumed, or somewhere along the way), our economic evaluation considered a range of project types and market locations (see Table 1).

**Table 1**

**Project types and markets included in IHS CERA analysis**

| Project Types | Markets |
|---|---|
| Greenfield upgrader | British Columbia (West Coast) |
| | Alberta (Edmonton) |
| Refinery conversion | Alberta (Edmonton) |
| | Quebec (Montreal) |
| | US Midwest (Chicago) |
| | US Gulf Coast (Coast) |
| | Asia (South China) |
| Greenfield refinery | British Columbia (West Coast) |
| | Asia (South China) |
| | Alberta (Edmonton) |

Source: IHS CERA.

*The diluents needed to transport the bitumen would be recycled back to Alberta by a pipeline.

*Market locations*

Although oil sands markets are geographically limited today, we anticipate that markets will expand.* Therefore, we have compared the economics in Alberta to those of existing and future markets:

- Existing markets: Alberta, the US Midwest
- Existing market, with large potential for future growth: the US Gulf Coast
- Future markets: eastern Canada and Asia (including export-orientated facilities along Canada's west coast)

For a more detailed explanation of future markets for oil sands, please see the IHS CERA Special Report *Future Markets for Oil Sands.*

*Project types*

We include three project types in our economic evaluation.

- **Greenfield upgrader.** Greenfield oil sands upgraders could be built in the Edmonton area (a region of almost 1.2 million people) of Alberta, close to where oil sands are extracted while providing access to export pipelines and local refineries.** Potential also exists to upgrade or refine bitumen "along the way" to the end consumer. For example, bitumen could be converted to SCO on Canada's West Coast before being exported to refineries in Asia or elsewhere. Fort McMurray was not included because only integrated upgraders (upgrader built in conjunction with a mine or in-situ project) have been built or proposed there.
- **Refinery conversion.** Modifying an existing refinery to convert capacity to process heavier crudes, like bitumen, is much cheaper than building a new one. Existing refineries in eastern Canada, US Midwest, US Gulf Coast, and Asia are all candidates for conversion projects. And although there are limited refineries to convert in Alberta, we have included this case in our analysis.
- **Greenfield refinery.** North America's demand for refined products is flat to declining, providing fewer opportunities for greenfield refineries. Even so, because demand for some refined products—specifically diesel—is growing, we have included an Alberta refinery in our results. In contrast to North America, developing countries—including China—are increasing their demand for all refined products. Although we anticipate that Asian refineries will supply most of the region's refined products, some volumes could be imported. Consequently, our analysis includes both an Asian greenfield refinery and a greenfield refinery on Canada's west coast targeting exports to Asia.

*Most oil sands crude oil is consumed in western Canada and the US Midwest. Although limited quantities of oil sands reach every refining region in North America (US West Coast, US Gulf Coast, US Rockies, US East Coast, and central and eastern Canada), pipeline infrastructure is currently a limiting factor for greater movements of oil sands to other markets.
**Source: Statistics Canada (2012), 2011 Census.

## Economic inputs

Although many factors have an impact on upgrading or refining finances, a few key variables dominate the economic return: the upfront capital costs, the price difference between light and heavy crudes (called the light-heavy price differential in our analysis), and the operating costs. To compare the economics among the project types and markets in our analysis, we identified probable values for each key variable (see Table 2 for a summary of inputs):

### *Capital costs*

These are all the expenses for constructing a facility, including the cost of equipment, machinery, steel, instrumentation, engineering, design, and construction labor. Since the scope of projects can vary considerably, we assumed a project cost range—high and low. Differences in project cost arise mostly from three factors:

- **Project scope.** The project scope can vary considerably among projects—even projects of the same type. In the case of refinery conversion projects, some refineries on the US Gulf Coast require little to no capital investment to increase their consumption of bitumen blends since they are already able to process heavy crudes.* Conversely, existing refineries in most other regions are configured to consume lighter crudes (light, sweet and light, sour). These less complex refineries require more extensive modifications before they can process meaningful quantities of bitumen. Even among greenfield refinery projects the scope can vary. For example, projects that produce more diesel (instead of gasoline, or other heavy products) require more costly equipment. For our analysis we assumed conversion projects resulted in traditional refinery product yields (about twice as much gasoline as diesel). For greenfield refineries we ran two assumptions. One case assumed traditional refinery product yields (two times more gasoline than diesel); the other assumed the refinery was configured to maximize diesel production, resulting in equal amounts of gasoline and diesel. Since diesel is a higher-value product, refineries that maximize diesel production generate higher returns.

- **Construction techniques.** Owing to differing construction methods, inland locations are more expensive to build. With ocean access, larger components or modules of the facility can be built off site. Once complete, the modules can be transported to site and assembled like building blocks. This technique materially reduces the labor requirements and—consequently—the cost. Access to the ocean is critical, because modules can be the size of a football field and need to be transported by ship. Although inland locations can use this method, since the modules must be transported by truck, this materially reduces the module size and corresponding cost savings.

- **Labor costs.** Construction labor is a large factor in why costs vary among regions. In North America direct labor typically makes up 30% of a project's total cost, and labor costs in Alberta are higher than those of other regions. One cause is the limited

*The US Gulf Coast region is home to 30% of the world's coking capacity already, and the region currently processes approximately 2.4 mbd of heavy crude—similar to the bitumen blends from the Canadian oil sands. Since many refiners are already well suited to process heavy crudes, it is conceivable that no investment (zero capital cost) may be require to consume bitumen blends. For our analysis we ran both our high and low cases with the same capital cost of $14,000 per flowing barrel (see Table 2).

## Table 2

### Key asssumptions for economic calculations

| Project Type | Location | Capital cost (US$ per 100,000 bd of capacity) | Operating cost (US$ per barrel) | Light-heavy differential[1] (average from 2016 to 2030, US$ per barrel) | Light crude input | Heavy crude input | Refined product yields (volume ratio of crude feed: gasoline: diesel)[2] |
|---|---|---|---|---|---|---|---|
| Greenfield refineries | Alberta (Edmonton) | $7.2–8.6 billion | $8.00–10.00 | $13.90–25.35[3] | Edmonton Par (in Edmonton) | Dilbit to bitumen (in Edmonton) | 2:1:1 to 3:2:1 |
| | West Coast | $5–6 billion | $7.00–9.00 | $14.22–24.51[3] | Arabian Light (on West Coast)[4] | Dilbit to bitumen (on West Coast) | 2:1:1 to 3:2:1 |
| | Asia (South China) | $2.8–3.5 billion | $4.50–6.50 | $12.16–14.66[3] | Arabian Light (in South China) | Dilbit (in South China) | 2:1:1 to 3:2:1 |
| Refinery conversions | Alberta (Edmonton) | $2.8–4 billion | $6.00–8.00 | $13.90 | Edmonton Par (in Edmonton) | Dilbit (in Edmonton) | 3:2:1 |
| | Quebec (Montreal) | $1.9–2.8 billion | $5.00–7.00 | $13.90 | Edmonton Par (in Montreal)[5] | Dilbit (in Montreal) | 3:2:1 |
| | US Midwest | $1.7–2.6 billion | $5.00–7.00 | $16.19 | WTI (Chicago) | Dilbit (in Chicago) | 3:2:1 |
| | US Gulf Coast | $0–1.4 billion[6] | $4.50–6.50 | $13.77–16.27 | LLS (St. James) | Dilbit (on US Gulf Coast) | 3:2:1 |
| | Asia (South China) | $1.2–2 billion | $4.00–6.00 | $12.16–14.66 | Arabian Light (in South China) | Dilbit (in South China) | 3:2:1 |
| Upgraders | Alberta (Edmonton) | $6–7 billion | $8.00–10.00 | $29.03 | SCO (in Edmonton) | Bitumen (in Edmonton) | n/a |
| | West Coast | $4.2–4.9 billion | $7.00–9.00 | $28.01 | SCO (on West Coast) | Bitumen (on West Coast) | n/a |

Source: Various sources, IHS CERA, 2013.

1. Light-heavy differential based on average price from 2016 to 2030 of the most prevalent light crude oil in each market and of dilbit or bitumen (depending on the project) delivered to each market. The price range was chosen to start in 2016 as it was deemed the earliest that a facility could be operational given a sanctioning decision today. Alberta-based oil sands crude prices were adjusted to reflect expected pipeline and tanker tolls—assuming the lowest-cost transportation options. Toll assumptions from Edmonton to each market are $4 to the West Coast; $6 to $8.50 to Asia; $4.50 to the US Midwest (Chicago area); $8 to $10.50 to the USGC; and $6 to Montreal. The tolls to both the USGC and Asia are less certain; therefore, a high and low transportation assumption resulted in a range for the light-heavy differential.
2. Refined product yield assumptions varied for greenfield refineries. The low case assumes that the refineries targets more gasoline, while the high case targets more diesel. For conversions, the refined product yields were assumed to target gasoline. With the exception of West Coast Refinery (where we assumed the products would be sold to the Asian market), we assumed that refined products would target the local market.
3. The wide differential is based on consuming bitumen; the narrow differential is based on consuming dilbit.
4. Arabian Light was chosen as representative of light sweet crude oil on the West Coast to reflect global crude access and orientation of facility as an export facility targeting Asia.
5. For Montreal, an inland crude (Edmonton Par) was chosen to reflect anticipated access to inland crudes which would come with pipeline access to inland markets.
6. Approximately 2.4 mbd of capacity on the USGC is already suited to consuming heavy oil sands crude oil, and no capital investment may be required.

regional pool of construction workers (demand from oil sands projects often exceeds local supply, requiring workers to be recruited from across Canada and the globe). Another is Alberta's landlocked location, keeping on-site labor requirements relatively high (see construction techniques). Climate is also a concern; cold weather decreases worker productivity.

*Light-heavy price differential*

Depending on the project type, the crudes used for the light-heavy price differential vary.

- **Greenfield refineries and refinery conversions.** When considering a heavy crude oil refinery investment, whether it's a greenfield facility or a conversion project, refiners compare the profit for consuming light crude to the profit from gearing up to take heavy crude. Heavy crudes are more expensive to process (it takes more energy and requires expensive equipment). In the end, the price discount for heavy crude must sufficiently cover the cost of the additional equipment and energy. For refinery conversion cases the light-heavy price differential is based on the difference in the price for the light crude and bitumen blend (for this report we assumed this to be dilbit).* For North American greenfield refinery cases, we assumed two potential scenarios—one where bitumen blend (dilbit) was converted to refined products and another where bitumen only was converted to refined products (assuming that the diluents used to transport the bitumen would be recycled back to Alberta for a fee).** In the later case the price difference between the light crude in the region and bitumen were compared.

- **Greenfield upgrader.** Since the input to an upgrader is bitumen and the output is SCO, our light-heavy price differential is based on the price difference between SCO and bitumen. Even when we considered the economics for an upgrader outside of Alberta, we used SCO and bitumen (again, assuming that the diluents were recycled back to Alberta for a fee).

Built into our Table 2 outlooks for light-heavy price differential is the assumption that new pipelines are constructed and western Canadian crudes have sufficient access to heavy crude markets from 2016 to 2030. Consequently, light-heavy price differentials reflect global market pricing and (compared with today) are relatively narrow.

*Operating costs*

As the name suggests, these are the day-to-day costs for the parts, maintenance, materials, labor, and energy required to run the facility. As with capital costs, the higher the operating costs, the more challenging the economics.

*The light crude oil chosen for each market was based on the expectation of the most prevalent light crude oil in the region where the facility is located when it is operating. For markets where the light crude oil or bitumen blend are not currently marketed, our best estimate of future transport costs was used.
**The cost associated with diluent return was included as part of the bitumen price.

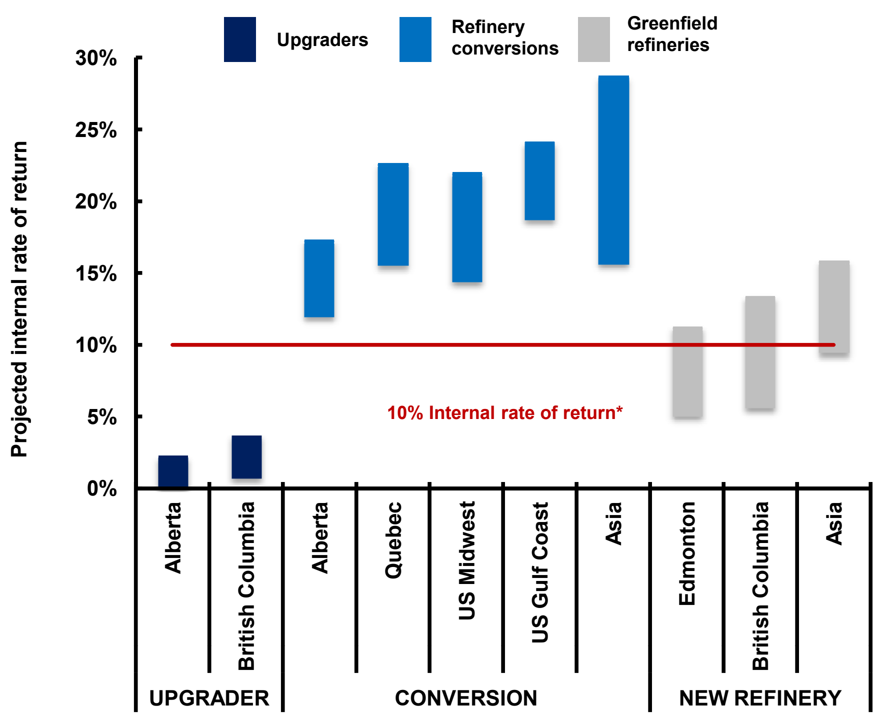
## The results

To compare the economics for processing bitumen in Alberta to that of other locations, we compared the internal rate of return (IRR) across all project types and markets (see Figure 3).* In reality, the IRR that is acceptable to secure an investment depends on the amount of debt versus equity funding for a project. The threshold IRR is unique for every company and project. Although we have highlighted a 10% IRR rate as an indicative threshold in Figure 3, this is not necessarily the cutoff for all projects. Actual thresholds could be higher or lower than this indicative value.

### *Refinery conversions*

As a group, refinery conversions provide the highest potential returns for processing heavy oil sands because the capital investment is significantly lower than that for a greenfield project. For the US Gulf Coast, we assumed a capital cost for converting to process heavy crude. However, numerous refineries in the Gulf region are already fitted to consume heavy oil and do not require conversions. And while North American conversion economics look strong, tight oil is a hurdle for these projects. Growing availability of light quality tight oil provides refiners little incentive for undertaking costly projects geared at increasing consumption of heavy crudes.

**Figure 3**
**Internal rate of return for oil sands upgrading and refining projects**




Source: IHS CERA.

*IRR is a way to measure the economics across all investments in a comparable manner and is a typical metric for comparing the economics among alternative projects. The IRR calculates the rate of return so that the net present value (NPV) of all future capital expenditures and revenues is zero.

*Greenfield refinery*

The strongest greenfield refinery investment returns are in Asia, where oil demand is growing. The difference between North America and Asia is primarily the result of Asia's lower project costs (see the box "Why are construction costs in China lower?"). Considering that Asia needs to build new refineries regardless (to keep pace with growing demand for refined products), the economics for heavy oil conversions are likely more reflective of the actual investment decision to process heavy oil. Consequently, if oil sands could access Asia in meaningful quantities, investment in greenfield refineries processing dilbit could be economic.

Although downside risk exists, given the right conditions, the economics of greenfield heavy oil refineries in Alberta and British Columbia could work. The ranges of potential returns in our results are driven mostly by the difference of project types considered. The weakest returns represent a refinery consuming dilbit and producing traditional product yields (more gasoline than diesel). The highest return reflects a refinery consuming bitumen and producing equal volumes of diesel and gasoline. While the actual greenfield refinery projects being advanced in Alberta (i.e., North West Redwater Partnership) and British Columbia (i.e., Clean Kitimat) are not direct comparisons with these generic examples, they are the most similar to the high IRR results.

There are downside risks to the Alberta and British Columbia greenfield refinery cases. For the Alberta refinery we assumed that the refined products were sold in the local market and did not oversupply it. If too much refinery capacity is built, refined products could flood the market and weaken product prices, challenging new refinery economics. For the British Columbia greenfield refinery case, we assume the refined products are transported to Asia and receive competitive prices. If transportation costs are higher than we assumed or if buyers require discounts, project economics would weaken.*

*Upgrading*

Although the economics for greenfield upgrading are challenging, returns for upgrading on the West Coast are a bit stronger than in Alberta. Key factors are lower capital costs and higher prices for light crude on the west coast compared with Alberta.**

So, how do the economics for upgrading in Alberta compare with pre-recession economics? When we rerun our Alberta upgrading economics, considering 30% lower capital costs and a light-heavy spread that reflects the thinking prior to the recession, the IRR of an Alberta upgrader ranges between 10% and 13%—considerably higher than our current outlook and above our indicative economic threshold for new investments.

Proponents of upgrading in Alberta have suggested that the government should boost the economics by creating incentives to upgrade. But what would it take to improve upgrading

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*Marine shipping costs can vary for a number of reasons: density of product, vessel size, distance, and global demand for tankers. In this report refined product transport costs from the west cost to Asia averaged from US$1.20 to US$2.00 per barrel depending on the product (2016 to 2030 average). This assumed using Aframax vessels transiting one way (no return) to South China.

**The outlook for west coast oil price is comparatively higher owing to the oversupply of light crudes in inland North America, which (even considering new pipeline connections) is expected to depress Alberta prices compared with costal ones—potentially in the range of US$2 to US$3 per barrel.

economics? Although there are a number of potential incentives to be considered; the cost of capital and the price of bitumen are two key levers:

- **Cost of capital.** The government could provide loan guarantees to third parties or launch its own upgrading enterprise. Both would reduce the cost of capital and, consequently, the IRR required for an investment to proceed. However, by doing this, the government takes on financial risk.
- **Price of bitumen.** The Alberta government has the option to receive royalties in the form of bitumen barrels instead of cash. The government could sell the royalty barrels at a discounted price to an upgrader. This would widen the light-heavy price difference and strengthen upgrading economics. However, this is a costly proposition. For the Alberta upgrader to boost the IRR to 8%, the bitumen price must be discounted by between US$10 and US$15 dollars per barrel. For a 100,000 bd facility, this subsidy would cost in the range of a half billion dollars a year.

### Why are construction costs in China lower?

The primary advantage over North America of building a refinery in China is low capital costs. Cost of labor is the key reason for the gap. Labor cost for a North American refinery project typically constitutes about 30% of the project's total cost; for China, it makes up about 10%. China's low labor rates factor into additional discounts for labor-intense manufactured goods—such as process equipment and fabricated steel products.

Projects built in China by joint ventures (JVs) with Western companies tend to cost more than projects built solely by Chinese companies. Typically, the cost of a Chinese-led project is lower because the Chinese companies generally pay lower wages, rely almost exclusively on Chinese engineering and construction contractors, and offer more scope and independence to these firms. JVs focus more on meeting Western quality standards and use more expensive international engineering resources, leading to higher overall costs. In our analysis we assumed costs that are reflective of a project built by a Chinese firm.

## PART 3: IMPLICATIONS—PRODUCTION, JOBS, GOVERNMENT REVENUES, AND GREENHOUSE GAS EMISSIONS

The conventional wisdom is that by pipelining bitumen, Alberta is exporting the jobs and economic benefits from upgrading or refining. This section challenges that thinking. Construction of bitumen processing facilities in Alberta places additional strain on a tight job market, increasing already high costs for oil sands development and further challenging investment. Alternatively, in a case where the region's limited pool of construction workers are deployed on bitumen-producing projects (instead of processing facilities), this drives production higher, creating more jobs and benefits to Alberta and Canada than construction of upgrading or refining facilities. It also reduces the GHG intensity of oil sands production.

### THE ALBERTA LABOR LIMIT

Alberta has a relatively small skilled trade workforce for constructing industrial projects—in our estimate about 17,000 workers are available for construction projects (welders, pipefitters, electricians, and other skilled trades) in Alberta. These workers support oil sands activity plus other industrial projects in the province, such as electrical generation, pipeline construction, infrastructure, and maintenance.

Often Alberta labor demand exceeds supply. Staffing industrial turnaround work (large maintenance projects that are periodically executed over a one- to three-month period in the spring and fall) is a perennial problem. To staff turnarounds, multiple projects demand thousands of skilled trade workers at the same time. During the turnaround seasons, workers from the rest of Canada are regularly called on. There were longer-term labor shortages in 2007 and 2008 when the demand for construction labor exhausted both Alberta and Canadian supply. Foreign workers were recruited to fill the gap. Now, once again, the Alberta labor market is constrained. Foreign workers are already at work on oil sands and other projects in the province, and their numbers are projected to ramp up over the next few years.

During the 2007 and 2008 labor shortage, projects faced expensive implications. Wage rates were one factor, increasing by 5.9% annually.* In addition total labor costs were boosted by overtime pay (over a 40-hour week, wages are paid at time-and-a-half and double rates), signing bonuses, employee recruitment costs, and living allowances. Worker productivity also took a hit: as the labor shortage grew, the average skill level of the workforce declined. But perhaps the most costly implication of the shortage was the expensive start-up and operational issues that numerous projects faced.

Since 2008, IHS CERA has been tracking and projecting industrial construction labor demand in the province as well as estimating available supply from Alberta and the rest of Canada.** Considering the IHS CERA outlook for supply and demand of Alberta construction workers, to avoid the need for foreign workers and the costly implications of a labor shortage, the province should keep total construction labor demand at around 25,000 workers. At this level, workers from other parts of Canada are still required to support projects, although

*Alberta building trade rates from third quarter 2006 to second quarter 2009.
**Labor data are available within our North American Crude Oil Market Service, www.ihs.com/products/cera/energy-forecasting/canadian-oil-sands.aspx.

no more than what has historically been recruited. Since the demand from other Alberta industrial projects averages near 8,000 workers, this means that oil sands demand would need to stay near 17,000 workers.

Critical to our assumption that labor remains a long-term constraint to growth are the expectations that oil sands growth remains strong and that government policy for accessing foreign labor does not change significantly from today (i.e., existing barriers for accessing and keeping foreign labor in the province continue).*

## Comparing two future scenarios for oil sands growth

In a scenario under which oil sands growth continues to be strong and construction labor continues to be the most critical constraint for growth, the province creates more jobs and economic benefits by not upgrading bitumen. To illustrate this, we compared the outcomes of two future scenarios to 2020: one where all new supply is from bitumen—referred to as bitumen only; and another where the amount of bitumen upgraded in the province stays about static with today—referred to as 60% upgrading. In both future scenarios we assume that Alberta is limited to 17,000 workers for new oil sands construction.** Even though this comparison is theoretical, it enables a quantification of the affects of upgrading (or not) on production growth, jobs, government revenue, and GHG emissions.

Although refining or other spin-off investments (such as petrochemical projects) were not included in the analysis, the jobs and economic benefits are not dissimilar to those from upgraders. Consequently, under an assumption that part or all of the upgrading capacity was substituted with refining or petrochemical capacity, the direction of the results would be similar.

### *Production*

Upgraders improve the quality of oil sands crude oil, but they do not add production. In a bitumen-only scenario, since all construction workers are deployed in bitumen-yielding mining or in situ projects, this results in almost 1 mbd more production by 2020 than the 60% upgrading scenario.

- **Bitumen-only scenario.** 2020 oil sands production (SCO and bitumen): 3.4 mbd
- **60% upgrading scenario.** 2020 oil sands production (SCO and bitumen): 2.5 mbd

### *Direct long-term jobs*

Long-term jobs from oil sands facilities include roles in project operation, supervision, administration, maintenance, and engineering, as well as periodic maintenance work. For

*In June 2012 the Canadian government changed the process for accessing foreign labor by introducing a accelerated labor market opinion process. The new process shortened the timeline, but it still takes a company 6 to 12 months to bring a new foreign worker to Canada. Other barriers include limits to the cumulative time that workers can stay in Canada and difficulty in immigrating.

**Other key assumptions include New production is assumed to be 80% of productive capacity additions. Growth is 45% from mining and 55% from in-situ projects. Interest rate for NPV calculations is 10% and the tax rate 29%. Values for crude for this analysis are consistent with those reported in part 2.

mines and in-situ projects, there are additional jobs for sustaining production levels (such as extending mine trains or drilling additional wells for in situ). For projects of comparable size, in-situ projects and mines provide more long-term jobs than upgraders. Consequently, when construction workers are deployed to build upgraders (resulting in fewer mining or in-situ projects being built), the number of long-term jobs in the province is actually lower.

- **Bitumen-only scenario.** New long-term direct jobs from now to 2020: 12,500
- **60% upgrading scenario.** New long-term direct jobs from now to 2020: 8,500

*Government royalties*

A royalty is the price Alberta charges a producer for the resource it extracts—bitumen in this case. Consequently, upgrading bitumen does not generate additional royalties for the province. Since the bitumen-only scenario results in almost 1 mbd more production, it also provides more royalties.

- **Bitumen-only scenario.** NPV of royalties for new facilities brought on between now and 2020 over 40 years: C$29 billion (annual average of C$5.5 billion per year)*
- **60% upgrading scenario.** NPV of royalties for new facilities brought on between now and 2020 over 40 years: C$15 billion (annual average of C$2.7 billion per year)*

*Income taxes*

As shown in part 2, Alberta upgraders struggle to generate positive cash flow and consequently pay minimal income tax. Since in situ and mining projects generate positive returns, the bitumen-only scenario (with higher production and cash-flows) results in more income tax revenue.

- **Bitumen-only scenario.** NPV of taxes for new facilities brought on between now and 2020 over 40 years: C$18 billion*
- **60% upgrading scenario**. NPV of taxes for new facilities brought on between now and 2020 over 40 years: C$7 billion*

*GHG emissions*

Along with production growth, aggregate emissions from oil sands are projected to grow. The GHG emissions for extracting a barrel of bitumen vary between 29 and 89 kilograms of carbon dioxide equivalent ($kgCO_2e$) per barrel; upgrading adds another 51 $kgCO_2e$ per barrel.** Considering the emissions produced in Alberta only, the bitumen-only scenario reduces the GHG intensity (because it avoids the extra GHG emissions from upgrading). However, when aggregate emissions from the oil sands are considered, the bitumen-only

*All NPV calculations assume 10% interest.
**The lower range is for mining bitumen, and the higher range is for producing bitumen from the cyclic steam stimulation method. Source: IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*

**Table 3**

**2020 GHG emissions compared: Bitumen-only and 60% upgrading scenarios[1]**

| | Alberta GHG emissions (extraction and upgrading) | | All GHG emissions (extracting through to refining) | |
|---|---|---|---|---|
| | Bitumen-only | 60% upgrading | Bitumen-only | 60% upgrading |
| 2020 aggregate GHG emissions from oil sands sector ($mtCO_2e$ per year) | 90 | 82 | 174 | 140 |
| 2020 average GHG intensity of production ($kgCO_2e$ per barrel) | 72 | 89 | 139 | 153 |

Source: November 2012, IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*

1. This analysis assumes no significant improvement in GHG intensity from 2012 to 2020 and does not factor in the impact of carbon capture and storage. The bitumen-only case considers the GHG emission for transporting diluents to the refinery and back to Alberta.

scenario (with higher overall production) results in higher total GHG emissions—8 megatons of $CO_2$e per year higher than the 60% upgrading scenario (see Table 3).

Expanding the boundary beyond Alberta (including GHG emissions from crude transportation and refining outside of the province) changes the magnitude but not the direction of the findings. Considering all emissions from oil sands extraction to refining (including upgrading and crude transport), the GHG intensity of the bitumen-only scenario is still lower than the 60% upgrading scenario.* The bitumen-only scenario still has higher aggregate emissions (stemming from the higher overall production).

Although the aggregate GHG emissions from oil sands in the two scenarios are significant, it is important to keep the total emissions in perspective. By 2020 the aggregate emissions from oil sands are less than 0.5% of global emissions** Further, in the absence of oil sands development, the majority of the emissions in Table 3 would still be generated. Without growth in oil sands, world oil demand would be unchanged. Consequently, oil sands supply would be substituted by other crude oils, which also generate GHG emissions.***

*On an intensity basis, although refining bitumen is more GHG-intensive than refining SCO, the combined emissions from the two-step process (upgrading bitumen and then refining) is still higher (resulting in 97 kg$CO_2$e per barrel, compared with 62 kg$CO_2$e per barrel for refining bitumen directly). Source: IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*
**Using IHS Global Scenario projections, 2020 GHG emission range from 32,000 to 37,000 mt$CO_2$e per year.
***When GHG emissions are viewed on a well-to-wheels basis—considering all emissions from producing oil through to combusting the fuel in a vehicle engine—oil sands are 4% to 18% higher than the average crude and within the same range as some other sources of oil that could replace oil sands supply. Source: IHS CERA Special Report *Oil Sands Dialogue: Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update.*

## PART 4: CONCLUSIONS

Prior to the onset of the global recession, the industry was set to upgrade and refine bitumen in the province. Oil sands companies were gearing up to spend more than US$100 billion on oil sands processing facilities in Alberta. Five years later, many projects have been canceled or delayed.*

The cancellations reflect the reality that, in many cases, value-added upgrading and refining in Alberta does not equate with adding profit. However, there are exceptions. Although the return is not as high as in Asia, given the right conditions the economics of new refinery projects in either British Colombia or Alberta could work (assuming that the refinery can consume bitumen, maximize diesel production, control capital costs to a minimum, and maintain a strong price for its products by not oversupplying the market). A key risk with any new refinery investment in North America is the flat to declining demand for refined products in the continent. Consequently, any sizable new refining facility must export its product overseas, likely to Asia, where it would need to compete with refiners there.

Another factor challenging North American upgrading and refinery conversion investments is the emergence of tight oil. Tight oil provides growing supplies of light crude, similar to upgraded oil sands (SCO). With growing supplies of light crude, the continental price difference between light and heavy crudes is expected to remain narrow. Tight oil is also reducing incentives for investing in heavy oil conversion projects, since refiners have plenty of light crude to process.

At this juncture, in many cases investors fail to get a reasonable return on the billions they must commit for a bitumen processing facility. However, this may not be all bad for Alberta. Considering the region's constrained labor market, less investment in processing facilities will enable faster growth in oil production, which also provides jobs and revenue to the province. Further, by deploying resources to build bitumen production now, the province is not closing the door to bitumen processing in the future. If the future unfolds differently than we assume and the economics for value-added investments strengthen, the option will always remain to upgrade and refine then.

*Refining and upgrading projects that are considered canceled or delayed include OPTI/Nexen future phases, Syncrude Mildred Lake debottleneck and expansion, BA Energy/Value Creation, Albian Sands Scotford 2, Statoil Upgrader, Total E&P Northern Lights, Peace River Oil BlueSky Refining, Husky Energy, and the Lloydminster upgrader expansion.

## REPORT PARTICIPANTS AND REVIEWERS

On 7 June 2012, IHS CERA hosted a focus group meeting in Calgary, Alberta, providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to upgrading and refining in Alberta. 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, for which IHS CERA is exclusively responsible.

Alberta Department of Energy

Alberta's Industrial Heartland Association

Alberta Innovates, Energy and Environmental Solutions

Alberta School of Business (University of Alberta)

American Petroleum Institute (API)

Canadian Association of Petroleum Producers (CAPP)

Canadian Building Trades (Building and Construction Trades Department, AFL-CIO, Canadian Office)

Canadian Oil Sands Limited

Cenovus Energy Inc.

Devon Energy Corporation

Conoco Philips Company

Chevron Canada Resources

Canadian Natural Resources Ltd.

IBM Canada

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

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## IHS CERA TEAM

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We also recognize the contribution of Carmen Velasquez, IHS CERA Associate Director, to this report.

# Future Markets for Canadian Oil Sands

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## About this report

**Purpose.** This IHS CERA report examines future markets for oil sands, the potential for oil sands in each market, and the key challenges in reaching them.

**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 at: www.ihs.com/oilsandsdialogue

**Methodology.** This report includes multistakeholder input from a focus group meeting held in Ottawa, Ontario, on 17 April 2012 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 end of report for list of participants and IHS CERA team).

**Structure.** This report has five sections:

- Part 1—Introduction
- Part 2—Why do the oil sands need new markets?
- Part 3—Future markets for oil sands
- Part 4—Factors effecting future markets for oil sands
- Part 5—Conclusion

# FUTURE MARKETS FOR CANADIAN OIL SANDS

## SUMMARY OF KEY INSIGHTS

**The “Great Revival” of North American crude oil production includes two pillars: tight oil and oil sands.** Together they are reshaping North American markets, providing economic benefits, and increasing continental energy security. By the end of this decade, combined production from tight oil and the oil sands could reach 8 million barrels per day (mbd)—becoming the largest source of supply in North America. Leveraging these supplies for economic and energy security benefits depends on the ability to construct transportation infrastructure to connect growing supply with demand.

**Tight oil boosts US oil security but does not offer oil independence.** Although growing supplies from US tight oil are substantial, the United States will still require oil imports for the foreseeable future, including from Canada and the oil sands.

**The rapid growth in North American supply is flooding inland refining markets, leaving oil sands subject to price markdowns.** This situation provides Canadian producers a financial incentive to expand market access in the United States, Canada, and beyond. It also highlights the risk of overreliance on limited markets and the need for options.

**The most significant future market for oil sands will come from expanding volumes to the United States.** Refineries in the US Gulf Coast and California both process oil sands today, but considerable room for expansion exists. The US Gulf Coast is one of the world’s most significant refining centers, and its considerable heavy oil processing capacity presents the largest opportunity for oil sands. California refiners can also process a sizable volume of heavy crude oil.

**Asian oil demand is expanding, providing opportunities for oil sands. However, timing is important.** If investors believe oil sands supply will not be available, then new Asian refineries may be ill suited for processing oil sands. Refining capacity in China alone is projected to nearly double by 2030. Some of these still-to-be-built refineries could be tailored toward oil sands crude oils.

**Although the need to expand and reach new markets for oil sands is pressing, pipeline projects associated with oil sands have come under increased scrutiny—contributing to delays and uncertainty.** Project economics are not alone in shaping future markets for oil sands. Although not every factor will influence future markets for oil sands, some of the most prominent ones include regulatory processes, local concerns, greenhouse gas emissions (GHG) and climate change, and Aboriginal rights in Canada.

—January 2013


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# FUTURE MARKETS FOR CANADIAN OIL SANDS

## PART 1—INTRODUCTION

How much room is there in the North American oil market for the anticipated growth from the Canadian oil sands? Five years ago this would have been an odd question to ask, given that US oil imports looked to maintain their decades-long growth. However, questions about US policy toward the oil sands combined with growth in North American tight oil supply have led to new questions about the future role for oil sands in US oil supply.

The oil sands currently meet over one-third of Canadian crude oil demand. Beyond Canada, the oil sands rely on a single export market—the United States.[1] At least until recently, this seemed a fine arrangement—one of the world's largest supplies of crude oil next to the world's largest consumer. However, as it turned out, the oil sands are not alone in the Great Revival of North American crude oil production. The same horizontal hydraulic fracturing technology that unlocked vast reserves of shale gas is now being applied to tight oil formations with startling effect. Over the past two years, supply from North American tight oil has increased by 1.5 mbd, and the growth is still accelerating. This year tight oil production overtook oil sands, and by 2020 it will be the single largest source of supply in North America. Tight oil is reshaping opportunities for oil sands in the United States and prompting Canadian industry and governments to seek new sources of demand in the United States, offshore, and elsewhere in Canada.

Pipelines are expected to remain the dominant method for oil sands to reach markets. However, timing for new pipelines is uncertain. Even when projects meet economic thresholds and have long-term financial commitments, other factors are slowing development. Keystone XL was denied owing to environmental concerns, the Northern Gateway project has been slowed, and even seemingly more straightforward projects like the partial reversal of Line 9 in southern Ontario have faced delays.

This IHS CERA report examines future markets for oil sands, the potential for oil sands in each market, and the key challenges in reaching them. The report has five parts:

- Part 1—Introduction
- Part 2—Why do the oil sands need new markets?
- Part 3—Future markets for oil sands
- Part 4—Factors affecting future markets for oil sands
- Part 5—Conclusion

Throughout this report we refer to various crude oil terms. See the box "Primer: Crude oil terms" for definitions.

1. Very small quantities of oil sands are currently exported off the west coast of Canada. These amount to less than half a percent of total oil sands exports.

## Primer: Crude oil terms

### Canadian oil sands

The immensity of the oil sands is their signature feature. Current estimates place the amount of oil that can be economically recovered from the oil sands at 168 billion barrels—the third-largest reserve in the world. The oil sands are grains of sand covered with water, oil, and clay. The "oil" in the oil sands is bitumen, a heavy oil of high viscosity.

In its natural state, raw bitumen is solid at room temperature and cannot be transported in pipelines. For transport, bitumen must be either diluted with light oil into a bitumen blend or converted into a light crude oil—called synthetic crude oil.

- **Synthetic crude oil (SCO).** SCO is produced from bitumen via refinery conversion units that turn heavy hydrocarbons into lighter, more valuable components 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°. However, since SCO produces a smaller range of products compared with conventional crude oils, without modifications a typical refinery can only use SCO for a fraction of its total feedstock.
- **Bitumen blends.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons. A refinery may need modifications to process large amounts of bitumen blends because these produce more heavy oil products than most crude oils. Bitumen blends typically have an API gravity of 22° (similar to other heavy crude oils like Mexican Maya). Typical bitumen blends include
  - **Dilbit.** The most common bitumen blend is dilbit—short for diluted bitumen. Bitumen is most often diluted with a natural gas condensate to make dilbit. A typical blend is about 72% bitumen and 28% condensate.
  - **Synbit.** When SCO is used as a diluent with bitumen this is call synbit. Synbit is typically half bitumen and half SCO.

### Tight oil

IHS CERA estimates that North American tight oil resources may contain over 90 billion barrels of economically recoverable crude and condensate (liquids). Tight oil is produced from a variety of rocks with low permeability and porosity—including shales, tight sands, and tight carbonates. Tight oil reservoirs that were once deemed uneconomic are now being produced profitably through the use of horizontal drilling and multistage completion techniques.

### Light, medium, and heavy crudes

In this report, all crudes with an API gravity of 31.1° or higher are considered light, and all crudes with an API gravity of 27° or less are considered heavy. Medium crudes are in between. Low sulfur crudes, or "sweet" crudes, contain less than 0.42% sulfur. Crudes with sulfur above this are considered sour. Crudes that are both low in sulfur and light are light, sweet crudes.

## PART 2—WHY DO THE OIL SANDS NEED NEW MARKETS?

This section explains that even though Canadian producers are driven to expand their markets, the United States will remain the primary outlet.

### THE SIZE OF NORTH AMERICA'S GREAT REVIVAL IN OIL SUPPLY

The scale of North America's Great Revival—from tight oil and oil sands—is significant; from now to the end of this decade (2020) combined production could grow by nearly 4.1 mbd.[1] Tight oil, a light sweet crude oil, is expected to lead this growth, growing at twice the pace of oil sands. Oil sands production is projected to grow from 1.7 mbd now to 3.2 mbd in 2020, while tight oil production (both crude and condensate) will grow from about 2.2 mbd now to about 4.8 mbd by 2020. Although this is good news for North American energy security, tight oil has implications for the oil sands, which are currently landlocked in the continent (see Figure 1).

**Figure 1**

**North American regions**


Source: IHS CERA.
20908-1

1. Diluent used to produce dilbit is not included in this value.

## THE FINANCIAL INCENTIVE FOR NEW MARKETS

Although tight oil supply is growing in other regions, so far the US Midwest has been the most affected.[1] Since 2011, light crude has oversupplied the US Midwest, resulting in regional oil price discounts. The price of crude in the US Midwest, as measured by West Texas Intermediate (WTI), has averaged $17 below comparable crude oils on the US Gulf Coast. Over the next few years, assuming that all currently planned pipelines are built, excess crude supply should escape the inland region, boosting prices for WTI and other inland crudes and realigning them to be more comparable with US Gulf Coast prices.[2]

Beyond short-term price discounts for inland crudes, there are other long-term implications from the Great Revival.

- **Shrinking market for US light crude imports.** Assuming US policy continues to prohibit the export of domestic crude oil offshore, tight oil will push out the majority of light crude oil imports in some regions.[3]
- **Lower crude prices for North American crudes.** Strong supply growth for light crude combined with limited outlets will lead to lower oil prices for both inland and US Gulf Coast crudes—potentially in the range of $3 or more per barrel (less than historical pricing relationships with globally traded crudes).

This situation provides Canadian producers and transportation providers a financial incentive to reach new market markets—ones that reflect global crude prices instead of discounted ones. It also highlights the risk of a lack of market diversity and the need for options.

## TIGHT OIL BOOSTS OIL SECURITY BUT DOES NOT OFFER OIL INDEPENDENCE

Although growth in tight oil supply is substantial, the United States will still require oil imports—including imports from Canada and the oil sands. On a net basis, the United States currently imports about 8 mbd of oil and refined products from foreign sources.[4] More than a quarter of this amount comes from Canada. Assuming flat oil demand from now to 2020, US domestic supply would need to grow by 8 mbd to eliminate foreign imports.[5] Meanwhile,

1. Not all states have been affected equally in the US Midwest. North Dakota, South Dakota, Nebraska, Kansas, and Oklahoma have been particularly affected.
2. Several pipeline projects contribute to our view that the gap will narrow between WTI and the Gulf Coast prices. These include the Seaway pipeline expansion and twinning (increasing from current 150,000 barrels per day [bd] to 400,000 bd in 2013 and 800,000 bd in 2014) and the Gulf Coast Pipeline Project (700,000 bd in 2013). Other projects that are important for western Canadian producers as well as producers in North Dakota and Montana include the Flanagan South expansion (160,000 bd in 2014), Keystone XL (700,000 bd in 2015), and greater rail capacity.
3. The United States prohibits the export of domestic crude oil. Exceptions exist for exports to Canada, from Alaska, for amounts not exceeding 25,000 bd of heavy crude oil from California, and exchanges with the US Strategic Petroleum Reserve.
4. Source: US Energy Information Administration (EIA). Average for the first eight months of 2012.
5. IHS planning scenario assumes no significant change in US oil demand between now and 2020. We do have an alternative scenario in which US oil demand drops by 1.3 mbd; however, this would require a higher oil price than in our current outlook.

tight oil production growth is occurring alongside declining conventional production, meaning that net US hydrocarbon liquids growth (between now and 2020) falls short at about 3 mbd.[1]

## PART 3—FUTURE MARKETS FOR OIL SANDS

To support expected production growth in the oil sands, new sources of demand in the United States, off the West Coast of Canada, and elsewhere are needed. This section identifies possible growth markets and the potential for oil sands in each.

### POTENTIAL GROWTH MARKETS

About one-third of oil sands production was consumed within Canada in 2011.[2] Beyond Canada, 80% of oil sands exports are consumed in the US Midwest, although some oil sands products are shipped to each of the US oil markets.[3]

Rail is already moving oil sands and is expected to play a greater role in the future. However, since pipelines are more efficient at moving large quantities of oil, we expect them to remain the dominant mode of oil sands transport. Looking at proposed pipelines, future markets for oil sands could include expanding volumes to the US Gulf Coast, eastern markets in the United States and Canada, and off the West Coast of Canada with California and Asia being the most likely markets (see Table 1).

These are not all the possible markets, just ones where pipeline access is currently contemplated. Additional pipeline projects, beyond current announcements, will be needed to support expected production growth. With total Western Canadian supply projected to more than double over the next two decades, from 3.2 mbd now to 6.5 mbd by 2030, pipeline capacity must grow by the same margin.[4]

What follows is a review of the prospects for oil sands (both bitumen blends and SCO) in each potential future market. Table 2 provides a summary of the key characteristics of each market.

### EXPANDING ACCESS TO THE US GULF COAST—A CRITICAL FUTURE MARKET

The US Gulf Coast is one of the world's most significant refining centers, with about 8.6 mbd of refining capacity. In 2011 over 70,000 bd of oil sands product made its way to the US Gulf Coast (via the Pegasus pipeline and rail). Oil sands volumes to this region are

1. Hydrocarbons include biofuels, natural gas liquids, crude, and condensate.
2. Source: National Energy Board.
3. According to the National Energy Board, 780,000 bd of oil sands exports went to the US Midwest in 2011. Other export markets included the US West Coast (largely Washington) (80,000 bd), US Rockies (61,000 bd), US Gulf Coast (70,000 bd), and to a much lesser extent the US East Coast (9,200 bd) and offshore markets (10,600 bd). Note these estimate do not include oil sands products blended and marketed as Western Canadian Select.
4. Outlook for supply growth includes oil sands and diluents, heavy and light conventional crude, and Canadian tight oil.

**Table 1**

**Major pipeline projects connecting oil sands to future markets**

| Destination | Pipeline project (proponent) | Route | Distance (km) | Capacity (bd) | Status | Proposed in-service date |
|---|---|---|---|---|---|---|
| US Gulf Coast | Flanagan South (Enbridge) | Flanagan, Illinois to Cushing, Oklahoma | 960 | 585,000 | Announced | 2014 |
| | Keystone XL (TransCanada Pipelines) | Hardisty, Alberta to Port Arthur, Texas | 2,750[1] | 700,000 | Regulatory review | 2015 |
| | Seaway reversal—Phase 1 (Enbridge/Enterprise Products) | Cushing, Oklahoma to Freeport, Texas | 800 | 150,000 | Online | 2012 |
| | Seaway—Phase 2 (Enbridge/Enterprise Products | | | 250,000 | Construction | 2013 |
| | Seaway—Phase 3 (Enbridge/Enterprise Products | | | 450,000 | Application | 2014 |
| East Coast | Canadian (natural gas) Mainline Conversion (TransCanada Pipelines) | Alberta to Montréal and Québec City, Québec | 3,500 | 300,000–800,000 | Conceptual | n/a |
| | Full Line 9 Re-reversal (Line 9b) (Enbridge) | Sarnia, Ontario to Montréal, Québec[2] | 640 | 300,000 | Regulatory review | 2014 |
| | Portland to Montreal Pipeline Reversal (Montreal Pipe Line) | Montréal, Québec to South Portland, Maine | 380 | 140,000 | Conceptual | n/a |
| West Coast | Northern Gateway Pipelines (Enbridge) | Bruderheim, Alberta to Kitimat, British Columbia | 1,180 | 525,000[3] | Regulatory review | 2018 |
| | Trans Mountain Expansion (Kinder Morgan) | Edmonton, Alberta to Westridge Marine Terminal in Burnaby, British Columbia | 1,150 | 450,000 | Announced | 2017 |

Source: Various sources and IHS CERA.
1. Keystone XL consists of two parts. A 1,897-km (1,179-mi) leg from Hardisty, Alberta to Steel City, Nebraska. And a 780-km (485-mi) leg from Cushings, Oklahoma to Nederland, Texas combined with a 76-km (47-mi) lateral to the Houston, Texas area (called the Gulf Coast Pipeline Project).
2. On 27 July 2012 the National Energy Board of Canada approved the partial reversal of 192-km section of Line 9 from Sarnia, Ontario to Westover, Ontario. The full reversal, filed on 30 November 2012, includes an expansion in capacity from Sarnia, Ontario to Westover, Ontario and reversing the line from Westover, Ontario to Montréal Québec.
3. Northern Gateway Pipelines also includes a parallel import pipeline with capacity to deliver 192,000 bd of condensate into Alberta for blending with bitumen.
Note: Characteristics of major pipelines for oil sands crude.

**Table 2**

**Potential future markets for oil sands**

| Market | Transport cost (US$/barrel)[1] | Market potential for SCO | Market potential for bitumen blends | Risks |
|---|---|---|---|---|
| US Gulf Coast | 8–10.5 | Limited—Despite large light capacity, opportunities are constrained by tight oil competition | Large—1.5 mbd. Further opportunities do exist, but could be limited by offshore competition | Tight oil competition |
| Eastern Canada (Québec and Atlantic Canada) | 5–7 | Medium ~250,000 bd | Limited with current refinery configurations | Pipeline approval required<br>Tight oil competition<br>Limited heavy capacity |
| US East Coast | 7–8 | Logistically challenged and expected to be limited by competition from tight oil | Limited with current refinery configurations | Pipeline approval required<br>Tight oil competition<br>Limited heavy capacity |
| US West Coast (California) | 5.50–6.50 | Market for pure SCO is limited; potential if blended with bitumen (see bitumen blends) | Large—700,000 bd. Opportunities could be tempered by offshore competition | Pipeline approval required<br>California climate change policy |
| Asia | 6.00–8.50 | Large—SCO could substitute for light crude oil imports | Limited now, but refining capacity is expanding; high potential for greater heavy refining capacity | Pipeline approval required |

Source: IHS CERA, Purvin & Gertz, an IHS company, 2012.
1. Transportation cost based on 2012 assessment. Actual transportation costs will vary over time and contract terms (long term or spot). Markets requiring tanker movements, such as to the US West Coast or Asia will vary by shipping demand and vessel size.
Note: Market characteristics of potential future market for oil sands.

expected to increase considerably with more than 2 mbd of new pipeline capacity planned to connect western Canada to the Gulf Coast in the next three years.

The region's refineries can consume about 2.4 mbd of heavy crudes, like bitumen blends. Today the majority of the heavy supply comes from Mexico (0.7 mbd) and Venezuela (0.8 mbd), with smaller contributions from Columbia (0.3 mbd) and Brazil (0.2 mbd).[1]

Although the region's appetite for heavy crude is substantial, further growth is not expected. Surplus light crude in the region (from tight oil production) will discourage refiners from investing in retooling their refineries to consume more heavy supply. Refinery conversions have historically been a major source of new demand for Canadian bitumen in the United States.[2] With static demand for heavy crude oil, opportunities for bitumen blends will primarily come from replacing imports from other suppliers. Mexican heavy supply is expected to decline, and there is uncertainty around future supply from Venezuela. If oil sands could displace most of the Mexican and Venezuelan imports, the opportunity for bitumen blends would be about 1.5 mbd. From a US Gulf Coast refiner perspective, Canadian heavy supply offers an alternative to other less certain crude suppliers.

The market for light sweet crude in the US Gulf Coast is over 2 mbd, large enough to absorb all oil sands SCO growth to 2030. However, SCO will face competition from growing supplies of US tight oil in this market.

Overall the US Gulf Coast is a huge crude oil market—nearly equivalent to all of China today. Consequently, the US Gulf Coast will be a critical part of the future for oil sands, particularly for bitumen blends.

## EASTERN CANADA (QUÉBEC & ATLANTIC CANADA)—A SMALLER MARKET WITH INDIRECT BENEFITS

Refinery capacity in eastern Canada is about 900,000 bd, with about half of this capacity aimed at exporting refined products, primarily to the United States.[3] Not all of the region's refining capacity is utilized, and crude oil consumption was around 760,000 bd in 2011.[4] Refining capacity is relatively small, dispersed, and geared toward light crude oil. Lacking any meaningful heavy crude oil capacity, expensive refinery conversion projects would be required to increase opportunities for bitumen blends.

Opportunities exist for SCO to displace offshore imports of light crude. However, since conventional refineries are restricted in how much SCO they can consume, the opportunity is limited.[5] We estimate that under existing configurations the ultimate potential for SCO in

1. Source: EIA, First eight months of 2012.
2. For example, over the next few years refinery conversions in the US Midwest at Marathon Detroit and BP Whiting will increase US heavy oil refining capacity by 340,000 bd. Both projects will be geared toward heavy Canadian bitumen blends. However, these projects were born of a time prior to the boom in tight oil production.
3. Irving Oil's refinery in Saint John, New Brunswick (300,000 bd), and North Atlantic Refining's refinery in Come By Chance, Newfoundland (130,000 bd), are principally export refineries.
4. Source: National Energy Board.
5. SCO yields a greater quantity of vacuum gas oil compared with light, sweet crude (about 38% versus about 30%); consequently the maximum amount of SCO a refinery can consume is lower than the maximum light oil volume.

the region is in the range of 250,000 bd. Given that competition from tight oil is anticipated, actual SCO consumption could be lower.

Even if oil sands consumption is limited in eastern Canada, there would still be indirect benefits from increased pipeline access.

- **Increased North American energy security.** In 2011 the region imported over 600,000 bd of foreign crude. Import dependence is expected to continue with domestic East Coast production declining. New pipelines linking inland production to eastern Canadian markets would allow domestic crudes, like SCO or tight oil, to displace offshore imports, strengthening North American energy security.

- **Provide relief valve for inland crudes.** Even if SCO is not consumed in large quantities in eastern regions, pipeline access would provide indirect benefits. Greater access could help reduce inland light crude oversupply, increasing opportunities for SCO inland.

## US EAST COAST—AN UNLIKELY MARKET FOR OIL SANDS

In 2011 the US East Coast imported over 1 mbd, notably 640,000 bd of light, sweet crude and 150,000 bd of heavy crude.[1] As transportation logistics develop, we expect that North American tight oil will displace most of the region's imports of light, sweet crude oil. New transportation corridors are already emerging. Although pipeline connections could be developed, the majority of new supply is expected to reach the region by rail, barge, and tanker. Rail transfers of inland crude to the region are ramping up, and Jones Act vessels are already shipping light crude from the US Gulf Coast to the US East Coast.[2]

For oil sands, the US East Coast market for heavy bitumen blends is limited. It is also an unlikely market for SCO, since production is more distant and has more difficulty reaching this market than US tight oil supplies. However, as a region with substantial capacity to consume light crude, it could function as an important relief valve to remove some tight oil that otherwise would be competing with SCO in other regions.

## US WEST COAST—LARGE, YET UNCERTAIN

US West Coast refining capacity is 2.6 mbd, and the region imports 1.1 mbd of crude oil.[3] The US West Coast is already a market for Canadian oil, importing about 170,000 bd of Canadian crude in 2011—half from oil sands.[4] While some Canadian crude is refined in California, the vast majority is consumed in the state of Washington. Canada provides a quarter of the 600,000 bd refined in Washington. Still, without refinery modifications, refiners cannot increase oil sands consumption much further.

1. Two thirds of the US East Coast imports of heavy crude are estimated to be from Canada.
2. The Jones Act restricts the movement of goods between US ports to vessels constructed in the United States, principally maintained in the United States, and predominately crewed by American citizens. This increases the cost of transporting crude by ship from one US region to another.
3. In this report the US West Coast does not include Alaska or Hawaii.
4. In 2011 oil sands imports to the US West Coast were 50,000 bd SCO and 30,000 bd bitumen (source: National Energy Board). Access to the US West Coast is currently via the Trans Mountain Pipeline through Vancouver and on to Washington state. Crude bound for California is moved by tankers from the Port of Vancouver.

California, however, is largely untapped and a potential future market for oil sands. California's 15 refineries have about 2 mbd of capacity. California is not a good market for light, sweet crude oils, such as SCO. Ninety percent of refining capacity, or 1.8 mbd, is geared toward other crudes, mostly heavy and medium crudes, with some light, sour capacity—bitumen blends could target this refining capacity. Considering the potential to replace imports from existing offshore suppliers, combined with expected declines in domestic production (both California heavy and Alaskan crude), the ultimate market potential for bitumen blends in California could exceed 700,000 bd.[1] Existing offshore suppliers can be expected to compete with oil sands for part of this market potential, however.

Despite the large opportunity for oil sands in California, the market potential is uncertain because of three factors:

- **West Coast pipeline and marine access must be expanded.** New pipelines and marine terminals beyond the current connections are required for market expansion. Two projects are advancing, but they face opposition and still require regulatory approval (see Table 1).

- **California policy could disadvantage oil sands.** California's Low Carbon Fuel Standard (LCFS) was revised on 26 November 2012. The LCFS aims to reduce GHG emissions from the well-to-tank life cycle of a fuel, including all GHG emissions related to the production, processing, and transportation. The goal is to have a fuel slate that is less carbon intensive, meaning fewer GHG emissions per unit of energy consumed. To meet the standard, refineries are expected to blend greater shares lower-carbon fuels, like biofuels or purchase credits generated by lower carbon-intensive fuels (like electricity). The consumption of more carbon intensive crude oil—like the oil sands—requires more offsets, potentially disadvantaging oil sands in this market. The California LCFS will estimate crude intensities using a standard model. The data used in the California model is not equal across all crude sources, as many crude suppliers provide little to no data for characterizing the GHG emissions from their oil production forcing California to develop default values. Since Canada provides more data than most other crude suppliers, this is another factor that could penalize Canada.

- **Potential for tight oil in California.** California is currently isolated from growing North American tight oil supplies. If tight oil emerges in the state, this could displace about 200,000 bd of market potential for bitumen blends.[2] Tight oil could come to California by pipeline—potential exists for conversion of some underutilized natural gas pipelines to move inland supply to the state—or from in-state production. California's Monterey Shale has promise.

1. Opportunities for oil sands are shared by two types of bitumen blends. Heavier dilbit blends could target the heavy crude oil import market and lighter synbit blends could go after the medium to light, sour import market.
2. Although tight oil is typically light, sweet crude and not ideal for California refiners, if tight oil was sufficiently cheaper than other crudes, we estimate that refiners could increase their consumption to this level.

## ASIAN MARKETS—MORE ABOUT POTENTIAL THAN CURRENT PROSPECTS

The greatest opportunity for oil sands in Asia is likely China—dominating the region with large growth expectations. Korea and Japan also hold potential. Other notable markets such as India are likely less attractive sources of demand, as they are farther afield and closer to large Middle East crude suppliers.

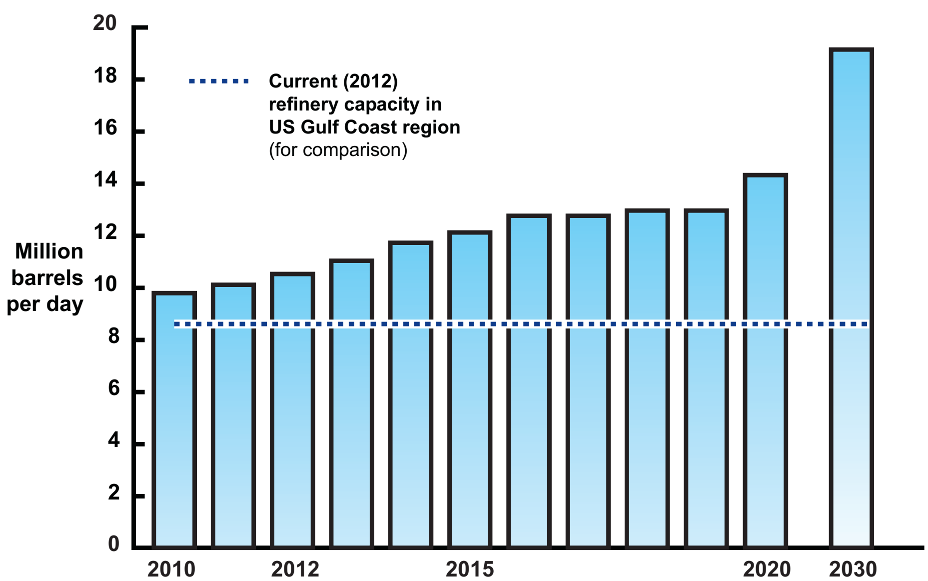
China's existing refining fleet has a capacity of about 10 mbd. Current refinery capacity is geared to light oil, so opportunities for SCO are greater than for heavy bitumen blends. In 2011 China imported nearly 1.4 mbd of light, sweet crude (similar to SCO), 2.6 mbd of light sour, and under 300,000 bd of heavy crude.[1]

However, just looking at Chinese refining capacity today is misleading, as the opportunity is more about potential than current prospects. With refinery capacity expected to nearly double between now and 2030, opportunities for crude suppliers will grow (see Figure 2).

China clearly has an interest in Canadian crude oil, investing over $10 billion in the oil sands over the past five years. Most recently China National Offshore Oil Corporation (CNOOC) offered to acquire Nexen Inc. for US$15.1 billion.[2] If it became clear that significant volumes of oil sands crude oil would become available for export to Asia, Chinese refining capacity

**Figure 2**

**Outlook for Chinese refining capacity**




Source: Purvin & Gertz, an IHS company.
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1. Crude definitions vary slightly from those established in our primer. Light, sweet crude includes crudes with sulfur content below 1% and above API 29°. Light, sour are all other light crudes. Heavy crudes here are those with API below 28°. We estimate total Chinese imports of all crudes in 2011 at 4.8 mbd.
2. On 7 December 2012 the Canadian government approved the acquisition.

could be purpose built to process it. China already has such plans with other sources of supply—the planned 400,000 bd heavy oil refinery near Jieyang is a partnership between China National Petroleum Corp. and Petróleos de Venezuela SA. Like Venezuela, Canada could provide an alternative source of supply and contribute to diversity in Chinese crude oil imports.

However, time is a factor since China is making investment decisions for the future today. Over the next five years (2012 to 2016 inclusive) China plans to add over 2.7 mbd of refining capacity. Assuming oil sands could reach this market in the next 10 to 15 years, before the bulk of the refining build-out is complete, there is greater potential to build refineries geared toward processing oil sands crudes.

Other Asian markets also hold potential. Japan is the third-largest consumer of crude oil in the world behind the United States and China. South Korea also is a large consumer. Lacking domestic production, Japan and South Korean markets depend on imports, primarily light crudes, similar to SCO. In 2011 Japan and South Korea imported 3.5 mbd and 2.5 mbd of crude oil, respectively.[1] Both markets are also geographically closer to Canada than China. Moreover, South Korea's large and growing storage capacity could make it an important energy hub for Asia and thereby an important redistribution point for oil sands.[2]

Growing oil demand and a high level of import reliance make Asia a promising market for any supplier. For the oil sands, transportation costs would be comparable with other markets and allow it to escape North American price discounts. However, access to Asian markets first requires greater pipeline and marine export capacity on the West Coast of Canada. Even though projects are proposed, they are not yet approved by the regulator.

## PART 4—FACTORS AFFECTING FUTURE MARKETS FOR OIL SANDS

Project economics are not alone in shaping future markets for oil sands. A number of other factors will also help or hinder oil sands ability to access markets. While delays plague energy projects throughout North America, they are particularly prevalent for oil sands–related transportation projects. This is in part because a well-organized opposition to oil sands development has emerged.

Although not every possible factor will influence future markets for oil sands, what follows are the most prominent possibilities: regulatory reviews, local concerns, Aboriginal rights in Canada, GHG emissions and climate change, employment and economic incentives, and North American energy security.

1. In addition to crude, Japan imported 390,000 bd of refined product, and South Korea exported about 350,000 bd.
2. Korean National Oil Corporation (KNOC) has been building storage capacity since 1980, and the Korean government views petroleum stocks as a means to ensure energy security. At present KNOC has over 127.5 million barrels of crude oil storage. Source: KNOC.

## REGULATORY REVIEWS

Greater interest in resource projects has contributed to lengthier reviews, committing projects to uncertain timelines and increased costs. For example, in Canada the review of the Northern Gateway, a project aiming to transport oil sands to the West Coast, was delayed by more than 4,400 requests to make an oral statement to the Joint Review Panel.[1]

In an effort to increase project certainty, the Canadian government changed its review process in 2012. Federal reviews must now be complete within 24 months, and the eligibility criteria to provide oral statements to the regulatory board (or panel) have been tightened.[2] It remains to be seen whether these changes will ultimately deliver greater timeline certainty. Shorter regulatory timelines could increase the chance of legal challenges to final decisions and ultimately slow projects.

## LOCAL CONCERNS

Stakeholders along key transportation corridors are understandably more concerned about local impacts than the broader project implications. For regions that provide critical access corridors for oil sands, such as Nebraska in the case of Keystone XL or British Columbia for access to the West Coast, concerns from local residents have contributed to delays. For Keystone XL, concerns in Nebraska ultimately contributed to delaying the project construction.[3] In Canada residents in British Columbia who face the prospect of increased tanker activity from West Coast pipeline access contributed to slowing the regulatory review for the Gateway project.

Nebraska and British Columbia are not isolated cases. Other instances are being recorded elsewhere.[4] With a well-organized opposition to oil sands development expanding efforts beyond actual oil sands development to the associated transportation infrastructure, public interest is likely to increase. As experience has shown, this can contribute to delays.

1. As of July 2012 the Joint Review Panel had received 4,462 requests to make an oral statement and 1,941 letters of comment. Source: Canada National Energy Board, "F- Letters of Comment" and "G – Requests to Make an Oral Statement," accessed 31 July 2012. On 7 December 2011, the Joint Review Panel announced that its review of the Gateway project would be delayed until late 2013, a year later than previously expected.
2. To address the review panel in person, an individual or organization must now be directly affected by the project or be a subject matter expert. Previously, anyone with an interest in the outcome was permitted to apply to make an oral presentation to the review board. Written statements are still accepted from all parties.
3. Keystone XL is a 700,000 bd pipeline proposal to deliver crude oil from Canada and tight oil from the Bakken region of North Dakota and Montana to the US Gulf Coast. The project met considerable opposition over the GHG emissions of oil sands crudes as well as the original route over the Sandhills and Ogagalla aquifer region of Nebraska. The original presidential permit was denied in 2012 owing to insufficient time to adequately review the project. The project developer, TransCanada Pipelines Ltd., has since resubmitted a permit application and has rerouted the project to address Nebraska's concerns. A decision is expected in 2013.
4. For example, consider the case of the partial reversal of a 192-kilometer section of Line 9 (Line 9a) between Sarnia, Ontario, and Westover, Ontario. A regulatory review of this type of project would not have normally required the full hearing ordered by the National Energy Board.

## ABORIGINAL RIGHTS

More than 1 million people (or 3.7% of the Canadian population in 2006) identify themselves as Aboriginal in Canada, including First Nations, Metis, and Inuit.[1] For energy projects such as pipelines and oil sands development, Aboriginal peoples have shared concerns about the potential environmental impacts on their traditional activities as well as economic benefits for their communities. Although they do not hold a veto over project approvals, Aboriginal people do have distinct rights that are protected by the Canadian Constitution Act, 1982.[2] For this reason, their attitudes toward a project can affect project timelines in Canada. Seeking greater certainty from Aboriginal groups is often a goal of project developers, and entering into private agreements where Aboriginal peoples can share in the economic benefit can help achieve this objective. This approach is becoming more frequent to reduce uncertainty in developing projects in Canada.

## GHG EMISSIONS AND CLIMATE CHANGE

GHG emissions pose two potential challenges for future oil sands markets. First, policies such as Low Carbon Fuel Standards (LCFS) could put higher GHG–intensity fuels, such as oil sands, at a disadvantage in some end markets. Second, absolute GHG emissions growth from the oil sands is a source of uncertainty for meeting Canada's climate change objectives. Should Canada be perceived as not doing enough to address its climate change commitments, greater efforts could be made to limit the import of oil sands products in other countries.

## EMPLOYMENT AND ECONOMIC INCENTIVES

North America benefits more from dollars spent domestically (in terms of economic development, job creation, and wealth) than from dollars exported to other countries through the purchase of offshore crude oil. The job creation benefits of shale gas production are widely recognized. IHS estimates that US unconventional oil and gas development has already supported more than to 1.7 million jobs, and this is projected to grow to 3 million jobs by 2020 (see the IHS report, *America's New Energy Future: The Unconventional Oil and Gas Revolution and the US Economy*, October 2012). Accelerating pipeline construction can help to increase domestic production, boosting jobs and economic benefits for North America.

## NORTH AMERICAN ENERGY SECURITY

The Great Revival of North American crude oil production has put Canada and the United States on a course toward greater energy security. However, to maximize the energy security benefits, more pipeline connectivity is needed between North America's crude production and refining centers. Benefits of new pipelines include stronger economics for domestic production and reduced dependence on offshore imports. Pipelines also provide hardwired connections between producing and refining regions, reducing dependence on oil transported by distant tankers and thus increasing North American energy security.

1. Source: Statistics Canada (2006), "2006 Census."
2. Section 35 of the Constitution Act, 1982 provides constitutional protection for Aboriginal and treaty rights.

The benefits from increasing the reach of domestic production have been recognized for some time. For instance, in the 1970s the government of Canada supported the construction of Line 9 to increase the reach of western Canadian crudes into Québec (see the box "Brief history of Line 9").

## PART 5—CONCLUSION

The Great Revival of North American crude oil production has two pillars: oil sands and tight oil. Both supply sources have important roles to play in future North American energy supplies—tight oil will provide much needed light, sweet crude oil, and oil sands will provide greater volumes of heavier bitumen blends. Together oil sands and tight oil have put North America on a new course toward increased energy security.

The United States will remain the primary market for oil sands (and the US Gulf Coast a critical market for future oil sands growth), but the development of other markets is also a pressing concern. Considering the scale of growth, expected price discounts for crude oil in North America, and uncertainty around the timing of future pipelines, Canada needs options.

Outside of the US Gulf Coast, the greatest opportunity for oil sands is the Canadian West Coast. This would open up markets in California and Asia, including China. Although California has significant potential to consume greater quantities of oil sands crudes today, Asia is more about future potential. Chinese refinery demand is set to nearly double from now to 2030, and new refineries could be built for oil sands crudes. However, time may be a factor since the majority of the Chinese refinery build-out will be completed in the next 10 to 15 years. Although we expect North American crudes to reach eastern regions of Canada and the United States in greater volumes, these regions may be better suited for tight oil than oil sands.

Despite compelling economic reasons for expanding oil sands markets, a number of other factors will influence market access. While some factors could expedite projects, others

### Brief history of Line 9

The 1973 oil embargo by the Organization of Arab Petroleum Exporting Countries had a dramatic impact on oil consumers and the world economy. Crude oil prices more than tripled within the year, and economic stability eroded. In Canada eastern regions reliant on imported oil suffered, while western oil-producing regions boomed. Canada moved to strengthen its energy security by reducing its dependence on foreign oil. Up to this point Canadian crude could only be piped from Alberta as far east as Sarnia, Ontario. In 1975 the Canadian government guaranteed revenues for a 20-year period to support a pipeline from Sarnia, Ontario, to Montreal, Quebec. In 1977 the line was in operation.

The line was not economic, and over the next 20-year agreement the Canadian government made deficiency payments. Following the end of the agreement in 1996, the pipeline was reversed since it was not economic without government support. With the surge in oil sands and tight oil production, the present owner of Line 9 has announced its intention to re-reverse the full line by mid-2014. Re-reversed flows could back out over 300,000 bd of offshore imports—cutting Canada's east coast imports of offshore crude in half.

could create delays. At least for the moment, it seems the trend may be more toward delay then acceleration, resulting in uncertain timing for new oil sands pipelines.

The size of North America's Great Revival and the resulting economic and energy security benefits to both Canada and the United States are substantial. The ultimate size of the benefits depends on the ability to develop pipeline corridors to markets—connecting growing supply with demand. What connections are made, when, and how, will shape the future development of both oil sands and tight oil.

## REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Ottawa, Ontario (17 April 2012), providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to future markets for oil sands. 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

Energy and Environmental Solutions, Alberta Innovates

American Petroleum Institute (API)

BP Canada

Canadian Association of Petroleum Producers (CAPP)

Canadian Oil Sands Limited

Cenovus Energy Inc.

Devon Energy Corporation

Enbridge Inc.

Conoco Philips Company

Chevron Canada Resources

Canadian Natural Resources Ltd.

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Statoil Canada Ltd.

Suncor Energy Inc.

Thomas Isaac, McCarthy Tétrault

Total E&P Canada Ltd.

TransCanada Corporation

## IHS CERA TEAM

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**STEVE FEKETE**, Purvin & Gertz an IHS Company, Managing Director, has been involved in a variety of refining and crude oil market studies including asset valuations and synergy analysis, refinery project feasibility and optimization studies, as well as market analysis and development of pricing projections for new production crude oils. Since joining Purvin & Gertz in 1997, Mr. Fekete initially gained broad refinery process engineering experience before moving into a short-term planning and economics position. In the economics and planning department in Houston, he was responsible for developing and presenting weekly and monthly economics packages which included crude selection and gasoline blending strategies. He was also responsible for providing capital feasibility and profitability analysis for a wide variety of proposed refinery projects; coordination of interplant agreements; and making recommendations to maximize refinery profit. Later in the firm's Calgary office he participated in and managed a wide variety of assignments involving Canadian and global crude oil and refining markets, technical reviews, and due diligence assistance. Prior to joining Purvin & Gertz in 1997, Mr. Fekete worked for several independent refining companies in the US Gulf Coast region. Mr. Fekete is a registered professional engineer (APEGGA) and holds a BSc from The University of Texas at Austin and an MBA from the University of Houston.

**KEVIN BIRN**, IHS CERA Associate Director, Global Oil, provides strategic analysis for the IHS CERA *Oil Sands Energy Dialogue.* His expertise includes oil sands development, Canadian pipeline infrastructure, energy modeling, and Canadian energy policy. Prior to joining IHS CERA Mr. Birn held various positions with the government of Canada as a Senior Economist at the Department of Natural Resources Canada. During this time he worked on an array of energy issues, including natural gas and crude oil supply and demand, pipeline infrastructure, energy modeling, and Aboriginal consultation. The majority of his work focused on the Canadian oil sands policy. Mr. Birn was the lead author of the Natural Resources Canada's 2010 oil sands paper, *A Discussion Paper on Oil Sands: Opportunities and Challenges.* Mr. Birn was also a member of the team that developed the North American unconventional oil outlooks and recommendations for the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources*. This included the Canadian oil sands, US oil sands, tight oil, oil shale, and Canadian heavy oil. Before his time with the government Mr. Birn briefly taught business economics at the University of Alberta School of Business and helped establish a software company of which he remains a partner. Mr. Birn holds a Bachelors of Commerce and a Master of Arts in Economics from the University of Alberta.

We also recognize the contribution of Carmen Velasquez, IHS CERA Associate Director, to this report.

# The GHG intensity of Canadian oil sands production: A new analysis

7 July 2020

**Kevin Birn**
Vice President

**Cathy Crawford**
Director

Crude Oil Markets | **Strategic Report**

# Contents

# The GHG intensity of Canadian oil sands production: A new analysis

**Kevin Birn,** Vice President

**Cathy Crawford,** Director

In 2018, IHS Markit made public a comprehensive analysis of the upstream greenhouse gas (GHG) intensity of the Canadian oil sands. The study included an analysis of past GHG emissions from 2009 to 2017 and an outlook about how emissions could evolve to 2030. Using the latest data available, as well some modeling improvements, this report updates and extends the analysis of upstream oil sands GHG emission intensity to 2018. It identifies the latest trends and discusses the sources of change to date.

## Key insights

- The overall weighted average of the upstream GHG intensity of Canadian oil sands continued to decline in 2018—falling 2% from 72 kilograms of carbon dioxide equivalent per barrel ($kgCO_2e/bbl$) in 2017 to 70 $kgCO_2e/bbl$ in 2018. This is about 20% lower than a decade earlier in 2009.

- The primary driver of the overall GHG emission intensity reduction in 2018 was not evenly distributed across the sector, with average intensity of mining emissions declining 10% year on year, while thermal operations increased 2% year on year. The scale of the reduction in emissions intensities in mining operations outweighed the rise in thermal operations.

- The ramp-up of a new oil sands mining operation with a GHG emissions intensity below the mining average, coupled with reductions in four out of the five legacy mining operations, contributed to a 10%, or 8 $kgCO_2e/bbl$, drop in the upstream GHG emissions intensity of oil sands mining to 75 $kgCO_2e/bbl$ in 2018 compared with 2017.

- The average GHG emissions intensity of steam-assisted gravity drainage (SAGD) production—the dominant source of thermal extraction—increased by 1 kgCO2e/bbl, or about 2%, to 65 $kgCO_2e/bbl$ in 2018. Meanwhile, the average intensity of cyclic steam stimulation (CSS) rose 9%, reaching 110 $kgCO_2e/bbl$ compared with 2017.

- The variability in the Canadian oil sands emissions intensity in 2018 was the largest estimated by IHS Markit, spanning roughly 160 $kgCO_2e/bbl$—from 40 $kgCO_2e/bbl$ to 201 $kgCO_2e/bbl$. This result means the most GHG-intensive operation was more than fourfold greater than the least intensive operation and implies the weighted average may do a poor job of representing any one operation.

—7 July 2020

## About this report

In 2018, IHS Markit made public a comprehensive review of past and future oil sands emission intensity in a report titled *Greenhouse gas intensity of oil sands production: Today and in the future*. The historical component of that study spanned 2008–17 for mining operations and 2009–17 for thermal operations. This report extends the historical assessment to 2018 and documents the sources of emissions intensity changes in recent years.

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

This report and past Canadian Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. Historical performance was derived using publicly available regulatory data and two purpose-built bottom-up GHG emission models for oil sands thermal operations and oil sands mining operations, respectively. A description and explanation of IHS Markit historical estimation models and methodology can be found in Appendix B from the 2018 IHS Markit study titled *Greenhouse gas intensity of oil sands production: Today and in the futur*e. IHS Markit has full editorial control over this report and is responsible for its content.

**Structure.** This report has five sections and two appendixes.

- Introduction
- The IHS Markit method
- GHG intensity of oil sands past: 2008–18
- Comparability and consistency
- Concluding remarks
- Appendix A
- Appendix B

## Introduction

The Canadian oil sands is one of the most scrutinized sources of crude oil supply in the world. The industry as it exists today was born during a time of high prices and scarce oil supply. Over the past decade, from 2009 to 2018, supply more than doubled from 1.6 MMb/d to nearly 3.5 MMb/d.[1] Greenhouse gas (GHG) emissions from production also rose, albeit at a slower rate, increasing 34 million metric tons of carbon dioxide equivalent ($MMtCO_2e$), or 62%, from 2009 to 2018.[2] Rising oil sands output, and GHG emissions along with it, has occurred amid a backdrop of growing global warming concerns and rising ambitions in Canada to reduce emissions. The Government of Canada is advancing a suite of policies aimed at tackling Canadian emissions reduction targets and recently announced its intention to develop a plan to achieve net-zero emissions by 2050.[3] A better understanding of Canadian oil sands GHG emissions and the factors influencing their evolution has only become more important.

IHS Markit has performed extensive analysis into the GHG emissions associated with production from the Canadian oil sands: absolute emissions, per unit of output or intensity, and how that compares with other sources of supply. In 2018, IHS Markit made public a comprehensive analysis of the historical upstream GHG emissions intensity of the Canadian oil sands and an outlook of future emissions based on existing trends to 2030. Using the latest available data, this report provides a fresh assessment of the upstream GHG emissions and emissions intensity of the Canadian oil sands to 2018 and documents the major sources of change.

This report is focused on the upstream emissions associated with oil sands production and can be considered the "Canadian-centric" share of emissions because most oil sands product is exported to be refined and combusted abroad. However, with most (70–80%) emissions occurring at combustion, a more holistic look at emissions over the entire life of a hydrocarbon is also important, and an update of the full life-cycle emissions is included toward the end of the report.

The report includes five sections and two appendixes. Appendix A provides detail data tables on study results. A discussion of sources of discrepancies between the prior IHS Markit analysis and this report is included in Appendix B.

Throughout this report, numerous oil sands terms are referenced. For more information, please refer to the box "Oil sands GHG primer."

## The IHS Markit method

In 2018, IHS Markit made public a comprehensive review of the upstream GHG intensity of Canadian oil sands extraction from 2009 to 2017. It involved the creation of two new bespoke oil sands emissions models—one for mining and one for thermal operations—which together provided incredible granularity into the drivers of oil sands emissions and sources of change. The study also included a detailed review of how future emissions could evolve based on existing technology and efficiency opportunities to 2030. The report was titled *Greenhouse gas intensity of oil sands production: Today and in the future* and forms the foundation for this study. Throughout this report, the 2018 report is referenced as IHS Markit (2018). Since that report was published, additional historical information has become available to enable the historical analysis to be extended to include 2018.

1. Owing to blending requirements, supply is greater than production. Over the same period, production rose from 1.4 MMb/d to 2.9 MMb/d.

2. "2020 National Inventory Report: Greenhouse Gas Sources and Sinks in Canada 1990–2018," Environment and Climate Change Canada (ECCC), 15 April 2020, https://unfccc.int/ghg-inventories-annex-i-parties/2020, retrieved 16 April 2020.

3. "Government of Canada releases emissions projections, showing progress towards climate target," Government of Canada, 20 December 2019, https://www.canada.ca/en/environment-climate-change/news/2019/12/government-of-canada-releases-emissions-projections-showing-progress-towards-climate-target.html, retrieved 30 March 2020.

## Oil sands GHG primer

The oil sands are perhaps the most scrutinized source of crude oil in the world. This attention is due, at least in part, to the sheer scale of the resource potential and concerns about environmental impacts. Recent estimates place the amount of remaining economically recoverable reserves in the oil sands at 164 billion bbl, 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 crude oil with high viscosity. Accessing, separating, and marketing bitumen from the oil sands require energy, resulting in GHG emissions. The intensity of upstream production emissions depends on the reservoir characteristics, the extraction method, and each facility's unique configuration (performance and energy sources). Two forms of extraction dominate: mining and in situ.

**Mining.** About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process, the overburden (vegetation, soil, clay, and gravel) is removed and used in associated infrastructure, such as roads and embankments, or stockpiled for later use in reclamation. The layer of oil sands ore is excavated using large shovels that scoop the material, which is then transported by truck to a processing facility. The ore is crushed or sized and then mixed with warm water and agitated, which causes the bitumen to separate. The energy used to power the vehicles involved in the mining process comes from fossil fuels, as does the heat used in the separation plant. In 2018, about two-fifths of supply came from mining, but, by 2030, as other forms of production are expected to outpace mining growth, mining's share of output will fall to about one-third. There are two forms of mining extraction:

- **Integrated mines or mined synthetic crude oil (SCO).** Legacy mining operations invested in and constructed heavy oil processing units upstream in the oil sands, which are often found integrated downstream into complex heavy oil refineries. Known as upgraders, these specialized processing units convert bitumen into a lighter SCO. As a result, upgraders add to upstream "mined SCO" emissions, which otherwise would occur downstream.

- **Unintegrated mines or mined dilbit (PFT).** In more recent years, two new mining operations have been completed that do not feature an integrated upgrader. Through a process known as paraffinic froth treatment (PFT), some of the heaviest components found in bitumen are precipitated out. The recovered bitumen is then diluted with lighter hydrocarbons (typically a natural gas condensate) and shipped to market as a bitumen blend or specifically a diluted bitumen (dilbit). This process avoids the energy associated with upgrading, reducing upstream GHG production emissions. However, the marketed dilbit is thereby more GHG intensive to refine, increasing downstream refining emissions. Still, on a net or full life-cycle basis, mined dilbit (PFT) is lower than mined SCO (this result can been seen in the life-cycle comparison discussed in the section titled "Comparability and consistency"). The PFT process has also been found to produce a modestly higher-quality bitumen and results in a dilbit product with a ratio of approximately four-fifths bitumen to one-fifth condensate.

**In situ.** About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. These deposits are the largest-growing source of oil sands production. In 2018, more than three-fifths of oil sands supply came from in situ operations, and, by 2030, it is expected to exceed two-thirds. Both primary and thermal extraction methods are deployed in situ. The primary extraction method is much more akin to conventional oil production and in 2018 accounted for about 5% of supply. However, as growth of other supply sources continues to outpace primary extraction, the primary extraction share of output is expected to decline to about 3% by 2030. Thermal production accounts for more than half of oil sands supply today (and nearly 90% of in situ supply). Thermal methods inject steam into the reservoir to lower the viscosity of the bitumen and allow it to flow to the

*_ST98: 2018: Alberta's Energy Reserves & Supply/Demand Outlook: Executive Summary_, Alberta Energy Regulator (AER), p. 7, https://www.aer.ca/documents/sts/ST98/ST98-2018_Executive_Summary.pdf, retrieved 15 April 2020.

### Oil sands GHG primer (continued)

surface. Natural gas is used to generate the steam, which results in GHG emissions. Bitumen produced from in situ operations is also too viscous to permit transport by pipeline and must be diluted with lighter hydrocarbons, making a bitumen blend. The most common blend is dilbit with a ratio of about 70% bitumen to 30% condensate. There are two dominant forms of thermal in situ extraction.

- **Steam-assisted gravity drainage (SAGD)** is the fastest-growing method, accounting for more than two-fifths of total oil sands supply in 2018 (nearly 75% of in situ supply), and is expected to dominate growth, accounting for about 55% of oil sands supply by 2030.

- **Cyclic steam stimulation (CSS)** was the first thermal process used to commercially recover oil sands in situ. CSS currently makes up 8% of oil sands supply. Growth in other sources of supply is expected to outpace CSS, and CSS share of total supply is expected to fall to 7% by 2030.

This section summarizes the method IHS Markit used to evaluate oil sands GHG emissions.

## Estimating historical oil sands emission intensities

This study is focused on the upstream GHG emissions of oil sands extraction and initial processing and documents the sources of emission intensity changes over time. Unless otherwise expressly stated, this report makes use of the same methodology, boundary conditions, and models deployed in IHS Markit (2018). For a detailed description of the IHS Markit method, please see IHS Markit (2018).

Our analysis included a detailed review of the two primary sources of oil sands extraction: oil sands mining and in situ thermal extraction (principally SAGD). Other forms of production—primary, experimental, and enhanced oil recovery (EOR) techniques used in the oil sands region—were included in the total oil sands industry average shown in this report using estimates from prior IHS Markit reports and other analysis but are not modeled in this study.

Differences in data and production processes necessitate distinct modeling approaches for mining and in situ operations. Data limitations affect the period for which historical estimates were possible: 2008–18 for mining operations and 2009–18 for in situ operations. Although this study period overlaps with IHS Markit (2018), the entire period was reestimated for this report. In addition to new facility and production data for the 2018 calendar year, new cogeneration performance data from Alberta Environment and Parks for 2015–17 were incorporated in our analysis and impacted thermal oil sands estimates over the entire study period.

## Boundary conditions are critical

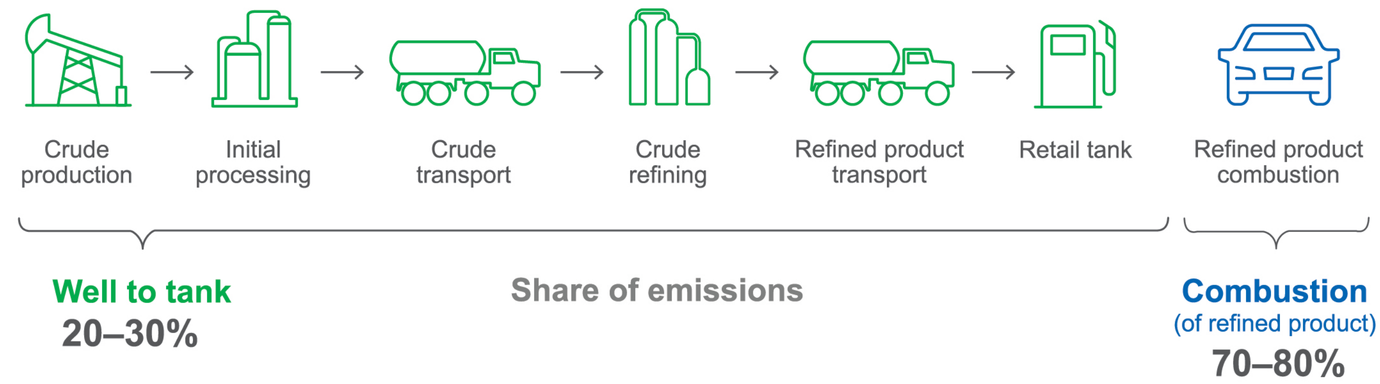
Understanding the emissions or system boundaries is critical when reviewing GHG estimates of crude oil and other hydrocarbons. Emission boundaries set the parameters for which emissions are being counted or included in the estimate and can, for obvious reasons, affect the results.

Interest in the GHG emissions intensity of oil and gas extends from upstream production all the way to its end use or combustion (see Figure 1). This is known as life-cycle analysis.

This study is focused on the upstream GHG emissions associated with crude production and initial processing as depicted in Figure 1. However, the scope of emissions considered by IHS Markit is broader and includes emissions associated with upstream production of fuel, such as natural gas or diluent used in the production and creation of diluted bitumen, as well as the import and export of electricity that can arise from facility use and cogeneration.

Figure 1

## Life-cycle GHG emissions of petroleum fuels




Source: IHS Markit

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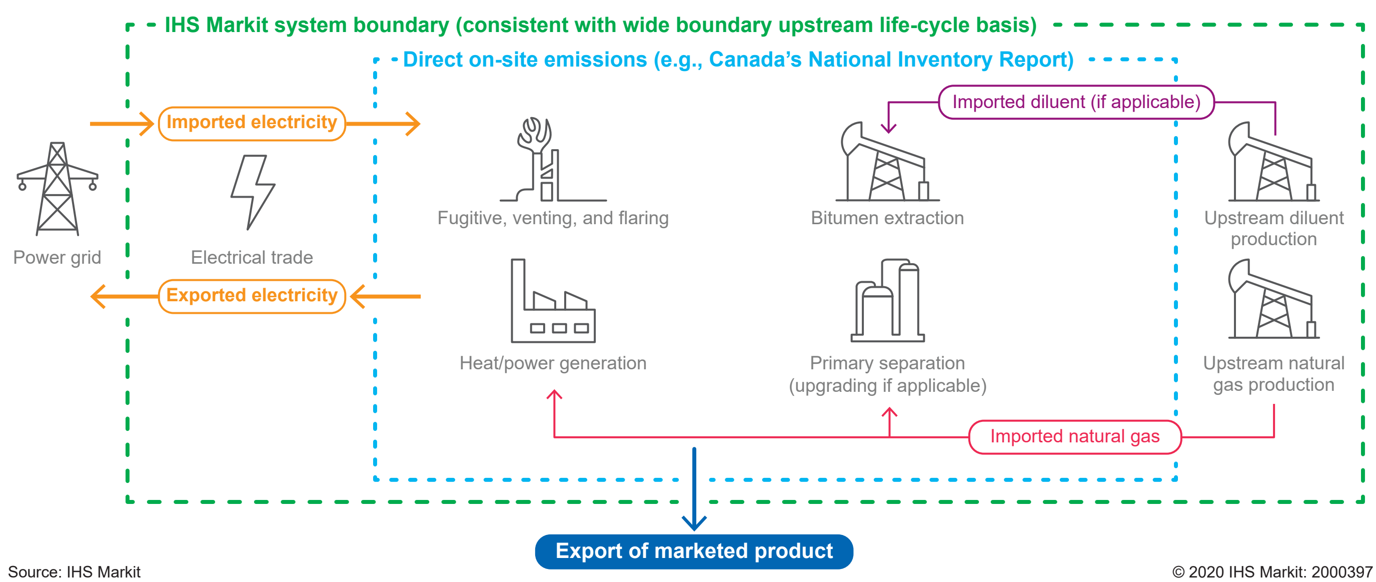
These system boundaries are consistent with prior IHS Markit research, which allows for apple-to-apple comparisons and integration with our existing work. In a few instances, different emissions boundaries are considered in this report, which are clearly marked.

See Figure 2 for a visual description of boundary conditions used in this report.

Figure 2

## System boundaries




Source: IHS Markit

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It should be noted that these emission boundaries differ from emissions captured by Canada's National Inventory Report (NIR), which focuses and reports solely on Scope 1 or direct emissions.[4] A comparison of IHS Markit results with absolute emissions as reported in Canada's NIR is made in the fourth section of this report: "Comparability and consistency."

Results are presented as the weighted average of the marketed product by extractive technology to best represent the GHG intensity of production that is sold and processed by downstream refineries. Where possible, estimates of minimum and maximum intensity are provided as well. Results include mined SCO, mined dilbit (PFT), total mining, SAGD dilbit, and CSS dilbit.

## GHG intensity of oil sands past: 2008–18

The Canadian oil sands continued its decade-long emission intensity reduction trend in 2018. This trend is shown in Figure 3. The weighted average upstream GHG intensity of the Canadian oil sands came in just under 70 kilograms of carbon dioxide equivalent per barrel (kg$CO_2$e/bbl)—down 2% from 2017 levels. Since 2009, the weighted average emission intensity has fallen 20%, or about 17 kg$CO_2$e/bbl.[5]

There is considerable variability in the GHG intensity of upstream extraction in the oil sands. The most intensive operation is over four times more GHG intensive than the least. IHS Markit has found a similar degree of variation in other plays globally, and caution is advised when interpreting the weighted average values as they may not represent any individual operation.[6]

The lower bound of the GHG intensity range in 2018 was set by a SAGD dilbit operation at 40 kg$CO_2$e/bbl. This level was nearly tied with that of a mined dilbit (PFT) facility. Meanwhile, the upper bound of the GHG intensity range rose to 201 kg$CO_2$e/bbl from a CSS operation, which is best classified as an outlier, representing less than 1% of total CSS output (or about one-fifth of a percent of total thermal production). The range of emission intensity associated with CSS operations is not depicted in Figure 3 simply because the figure becomes difficult to interpret (too many overlapping areas). CSS emissions are included in the weighted average presented in Figure 3.

The primary drivers for the continued decline in the average GHG intensity of the Canadian oil sands were the result of increasing production from lower GHG-intensive mined dilbit (PFT) and ongoing efficiency improvements of mined SCO, with three out of the four legacy operations experiencing GHG emission intensity reductions in 2018. These drivers as well as historical emissions by each major oil sands subsegment are documented in the following section. These subsegments include mining (mined SCO and mined dilbit [PFT]) and in situ (SAGD dilbit and CSS dilbit). Oil sands mining and thermal in situ (SAGD and CSS) accounted for more than 90% of all oil sands supply in 2018.

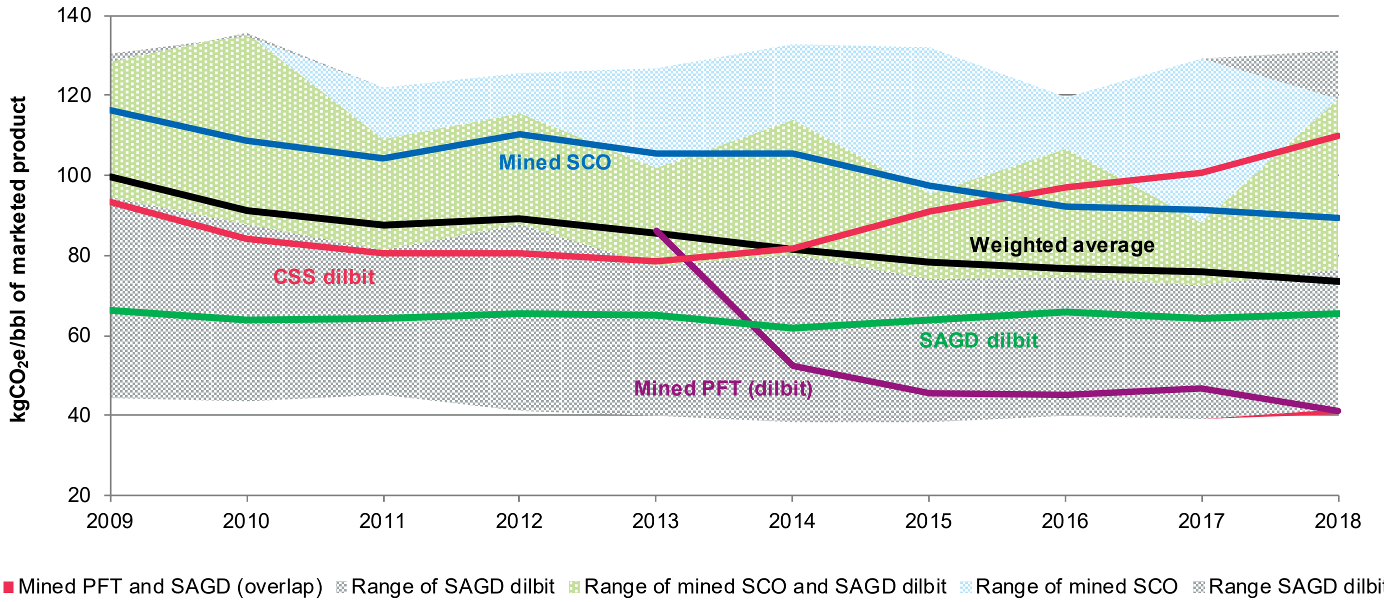
4. "Canada's official greenhouse gas inventory," Government of Canada, https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/inventory.html, retrieved 30 March 2020.

5. Estimate of total oil sands average includes oil sands CSS, SAGD, mined SCO, mined dilbit (PFT), primary, experimental, and EOR. GHG intensity estimates of primary, experimental, and EOR were held static and sourced from the IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*.

6. See the IHS Markit *Understanding the GHG intensity of Crude Oil: The challenge of averages*.

Figure 3

**Range and average of GHG intensity of oil sands extraction by year and by technology on a marketed product basis, 2009–18**




Note: Estimate of total oil sands average includes oil sands CSS, SAGD, mined SCO, mined dilbit, primary, experimental, and EOR. Estimates for primary, expermential, and EOR are a very small share of oil sands production, and constant values were used.
Source: IHS Markit



## GHG intensity of oil sands mining in 2018

Oil sands mining made up more than two-fifths of oil sands supply in 2018. Production is composed of two forms of surface mining operations. One is mined SCO, which is a mine that incorporates heavy oil conversion capacity known as an upgrader, which enables the production and marketing of light SCO. The second is mined dilbit (PFT), which is a mine capable of marketing bitumen without an upgrading unit. The mined dilbit (PFT) process lowers the upstream energy and thus GHG emissions of production but also requires blending the raw bitumen with diluent to enable its transportation to market by pipeline. Mined SCO accounted for nearly 30% of oil sands supply in 2018 and mined dilbit (PFT) just over 13%.

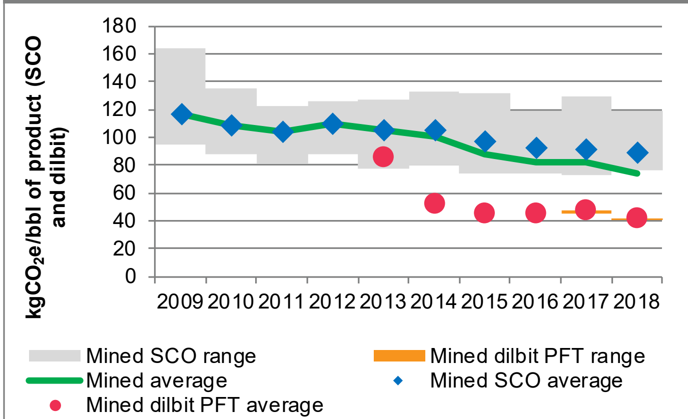
IHS Markit found that the weighted average GHG intensity of oil sands mining continued its decade-long trend of year-on-year reductions in 2018. As shown in Figures 4 and 5, the average intensity of oil sands mining fell by 10%, or 8 kg$CO_2$e/bbl, to 75 kg$CO_2$e/bbl from 2017 to 2018. This was the second-greatest year-on-year drop in the estimated history of oil sands mining emissions. The largest was a 12% reduction during 2014–15.

The variability or range of mining emissions spanned over 78 kg$CO_2$e/bbl, with the least GHG-intensive mining operation being a mined dilbit (PFT) facility at about 41 kg$CO_2$e/bbl and the most GHG-intensive operation at 119 kg$CO_2$e/bbl from mined SCO—a nearly threefold range from top to bottom.

The major driver for the intensity reduction between 2017 and 2018 was the ramp-up of the latest oil sands mining operation, the Fort Hills Partnership. As a mined dilbit (PFT) facility, it has a much lower upstream GHG emission intensity than the average (on an upstream basis, the GHG intensity of mined dilbit [PFT] is roughly half that of mined SCO; on a full life-cycle basis, the difference is smaller as dilbit is more GHG intense to refine). As shown in Figure 5, the ramp-up of this new operation accounted for nearly three-quarters of the 8 kg$CO_2$e/bbl reduction. As production ramped up over 2018, it pulled down the average GHG intensity of mining.

Figure 4

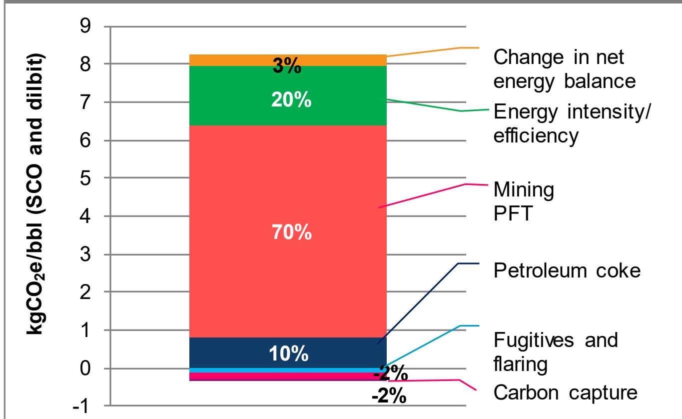
**Historical GHG emission intensity of mined oil sands by marketed product (SCO and dilbit)**




Source: IHS Markit © 2020 IHS Markit

Figure 5

**Source of oil sands mining GHG intensity improvement (2017–18, 8 $kgCO_2e$/bbl of product)**

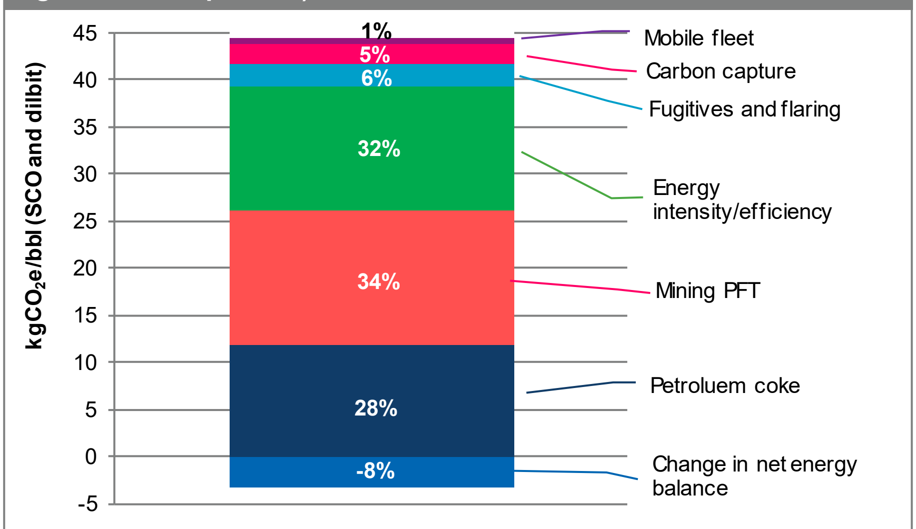



Source: IHS Markit © 2020 IHS Markit

The next largest contributor came from energy efficiency improvements, followed by further reductions in the use of petroleum coke.[7] Much of the energy efficiency gain can be attributed to improvements at one larger operation that has historically had above-average GHG intensity compared with its peer group. In 2018, this one operation experienced a nearly 10 $kgCO_2e$/bbl drop in upstream intensity. With large volumes coming from few facilities, the performance of one operation can materially affect the average.

Figure 6

**Source of oil sands mining GHG intensity improvement (2009–18, 42 $kgCO_2e$/bbl of product)**




Source: IHS Markit © 2020 IHS Markit

Reductions over the past decade now total 42 $kgCO_2e$/bbl, or 36%, from 2009 to 2018.[8] Figure 6 presents a breakdown of the major drivers of emission reductions over the past decade.

### Mined SCO

Although both mined SCO and mined dilbit (PFT) are both first and foremost surface mining operations, they are distinct and should be looked at separately.

In 2018, the average intensity of mined SCO continued its decade-long trend in reductions, falling 2 $kgCO_2e$/bbl, to 89 $kgCO_2e$/bbl. This result represents a 3% reduction from 2017. Over the past decade, the emissions intensity of SCO fell nearly a quarter, or 27 $kgCO_2e$/bbl. The primary driver of the emission intensity reductions was attributable to improvements

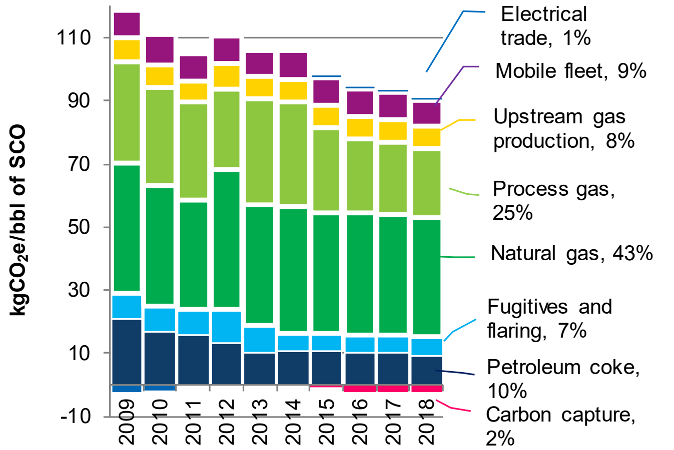
7. It is also important to note that a petroleum coke emission intensity reduction can result from actual reductions in the use of petroleum coke or an increase in output produced without the use of petroleum coke (i.e., increases in production while petroleum coke consumption is held constant).

8. For the first data point IHS Markit has in 2008, emission reduction is less pronounced, falling about 39 $kgCO_2e$/bbl owing to slightly lower emissions in 2008 versus 2009. See Appendix A for data tables for more information.

in energy efficiency or fuel use per unit of output, which includes petroleum coke, and mobile mining fleet efficiency. These changes are depicted in Figures 7 and 8.

Figure 7

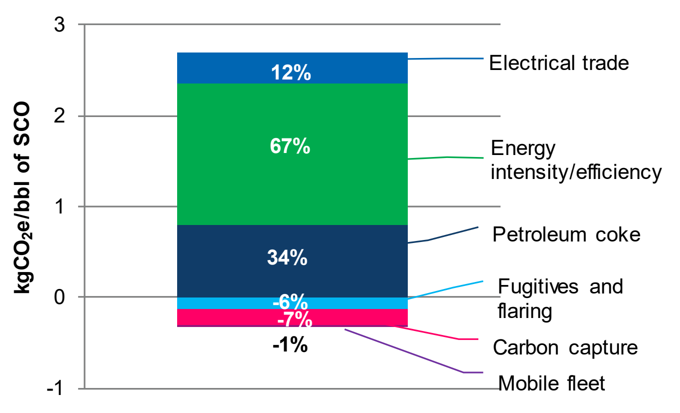
**Composition of mined SCO intensity, 2009–18**




Source: IHS Markit © 2020 IHS Markit

Figure 8

**Source of oil sands mining GHG intensity improvement (2017–18, 2 kgCO$_2$e/bbl of product)**




Source: IHS Markit © 2020 IHS Markit

## Mined dilbit (PFT)

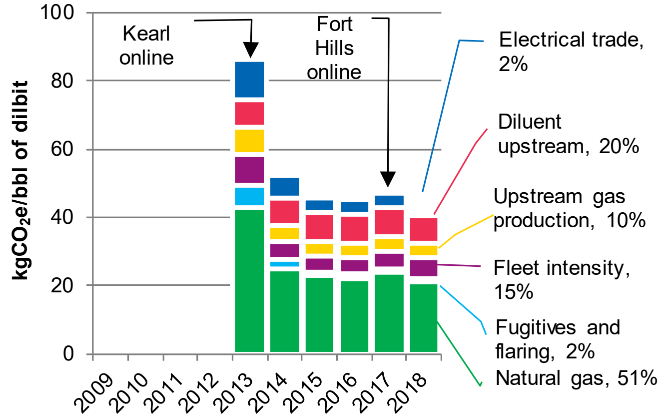
Mined dilbit (PFT) is the newest form of oil sands mining extraction. Presently, there are only two mines operating that market dilbit.[9] They are Imperial's Kearl facility, which came online in 2013, and the Fort Hills Partnership, which achieved first oil late in 2017 and ramped up over 2018.

In 2018, the average intensity of mined dilbit (PFT) fell by nearly 6 kgCO$_2$e/bbl, or 12%, to average 41 kgCO$_2$e/bbl. This result is visible in Figure 9 and was surprising given the majority of the ramp-up of Fort Hills occurred over 2018. Typically, during the ramp-up of new oil-producing operations emission intensity tends to be higher than normal as production generally would lag the ramp-up of energy use. However, in 2018 the impact of the ramp-up of the Fort Hills project did not appear to hurt average mined dilbit (PFT) intensity. This result was in part due to the initial stages of the ramp-up, which began in late 2017, splitting part of the ramp-up over two calendar years (partially visible in Figure 9). The other part of the story behind the muted impact of the ramp-up on the emission intensity was due to what appears to have been a relatively efficient ramp-up where power consumption came up with output and the facility was able to export surplus power to the grid, which under IHS Markit boundary conditions offset part of the emissions intensity rise. In Figure 10, some characteristics that would be expected of a large facility ramping up operations are more visible, such as the impact of the rise in fleet movement with production lagging output, the impact of the ramp-up of cogeneration increasing exports to the electrical grid, and the improvement in energy use as production increases. This latter point was assisted by improvements at Kearl, where emission intensity declined as output rose.

9. Technically, the first mining operation to make use of PFT was Albian Sands, which made use of PFT to stabilize the bitumen for transport to its upgrader located in Edmonton, Alberta. However, this facility only markets SCO.

Figure 9

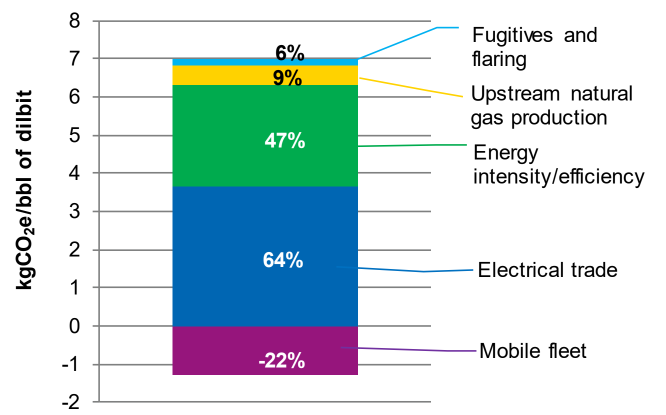
**Composition of mined dilbit (PFT) intensity, 2009–18**




Source: IHS Markit © 2020 IHS Markit

Figure 10

**Source of oil sands mined dilbit PFT GHG intensity improvement (2017–18, 6 $kgCO_2e/bbl$ of product)**




Source: IHS Markit © 2020 IHS Markit

## GHG intensity of oil sands thermal extraction in 2018

Thermal oil sands extraction accounted for more than half of total oil sands supply in 2018. Primary, experimental, and EOR in the oil sands region (which is not necessarily oil sands reservoirs) made up about 7% of oil sands supply. SAGD is the dominant form of production and the fastest-growing source of oil sands supply over the past decade. SAGD involves the continuous horizontal injection of steam into oil sands reservoirs and recovery of bitumen and water. Over the past decade (2009–18), SAGD was responsible for nearly three-fifths of oil sands supply growth and in 2018 accounted for more than two-fifths of total supply.

CSS, also known as huff and puff, makes use of vertical wells for temporal periods of steam injection and recovery back up the same well (hence huff and puff). Over the past decade, CSS production levels have not materially changed and in 2018 accounted for about 8% of oil sands supply. CSS is not anticipated to grow in the IHS Markit outlook. Although CSS is included in our study, our analysis is focused on SAGD given it is the single-largest form of source of supply and is expected to dominate growth. Although SAGD and CSS are both thermal forms of extraction, the choice between them relates primarily to reservoir characteristics, and thus we treat them separately. This situation differs from mining where there is fundamentally no differences in the underlying resource that influence the choice of extractive approach.

### SAGD dilbit

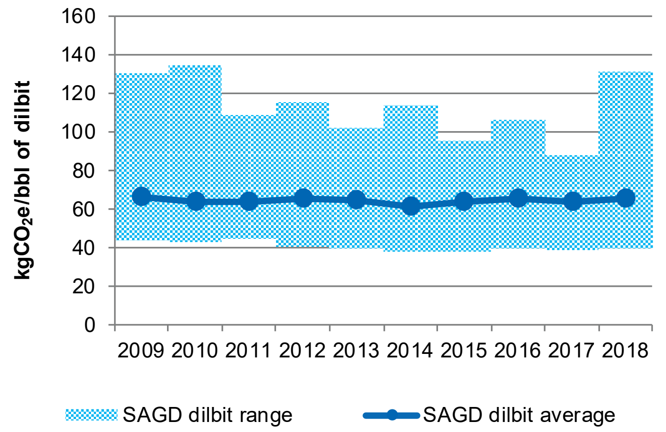
Consistent with the prior IHS Markit report, the GHG intensity of SAGD was relatively unchanged. As shown in Figure 11, the average intensity of SAGD dilbit increased by 1 $kgCO_2e/bbl$, from 64 $kgCO_2e/bbl$ in 2017 to 65 $kgCO_2e/bbl$ in 2018. Meanwhile, the range of GHG intensity in 2018 expanded owing to relatively low-volume, higher GHG-intensive operations. In 2018, the least GHG-intensive SAGD operation was 40 $kgCO_2e/bbl$, with the most GHG-intensive operation being 131 $kgCO_2e/bbl$—a span of 91 $kgCO_2e/bbl$. These outliers contributed to the modest increase in the annual average emission intensity and marks the first time in nearly a decade that the upstream GHG intensity of a SAGD dilbit operation exceeded that of mined SCO.

Interestingly, although there was a greater range or variability in the span of emissions, the variance or dispersion of facilities from the mean continued to decline in 2018. This relationship is visible in Figure 12, which shows the distribution of all SAGD operations' steam-to-oil ratio (SOR) by year.[10] It is also visible that

10. SOR is the volume of steam required to produce one barrel of bitumen and is highly correlated with GHG emissions.

Figure 11

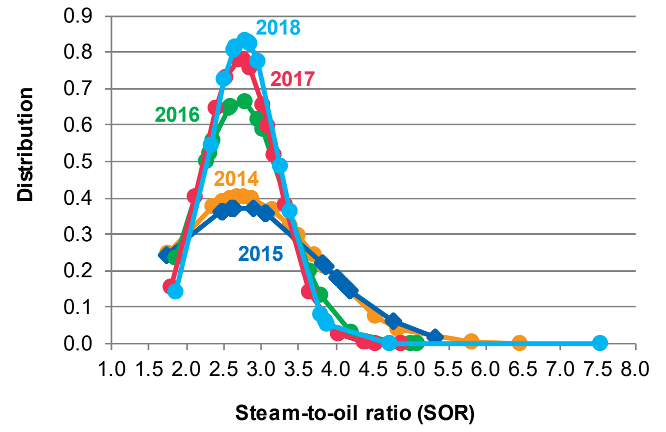
**Historical GHG intensity of SAGD dilbit, 2009–18**




Source: IHS Markit © 2020 IHS Markit

Figure 12

**Distribution of SAGD SOR by year**




Source: AER, IHS Markit © 2020 IHS Markit

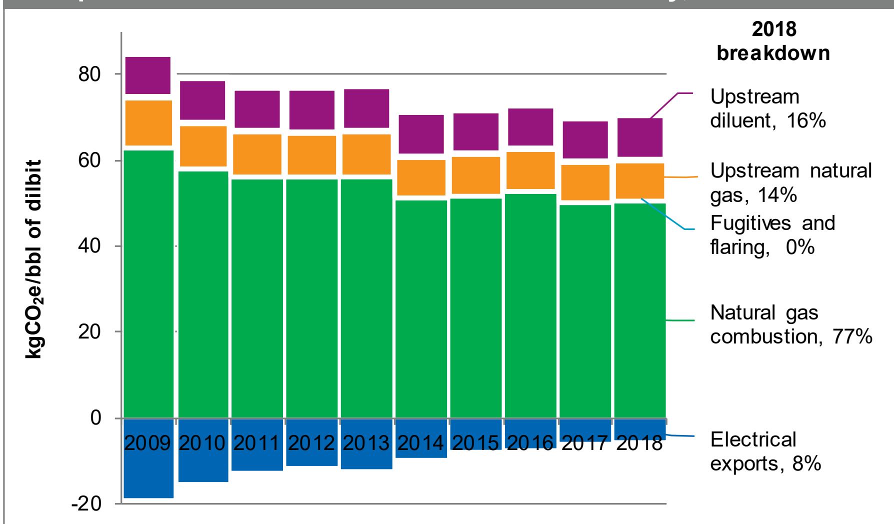
the number of higher SOR outliers declined each year, while in 2018 there was one very pronounced extreme outlier setting that upper bound of SAGD intensity.[11]

The drivers of the long-standing stagnation of the average GHG intensity of SAGD dilbit are in part attributable to the choice of emissions boundaries deployed by IHS Markit and the industry's historical relationship with cogeneration.

IHS Markit analysis includes energy that is bought and sold from the electrical grid. Over time, as SAGD production has grown, facilities increased their own use of the electrical power from their cogeneration units. On a net basis, the greater use of on-site electrical power generation has led to declining electrical exports and associated intensity credits (as per IHS Markit emissions boundaries used in this report). Over the same period, SAGD operations have become more efficient with declining steam or natural gas per barrel. These two factors are clearly visible in Figure 13, with natural gas combustion intensity and electrical export intensity declining consistently over the past decade. The net impact of these two factors largely offset each other, leaving overall emission intensity relatively flat under IHS Markit emission boundaries. If we were to change the emission boundary conditions to be consistent or comparable with Canada's NIR, which includes only Scope 1 or direct emissions (see

Figure 13

**Composition of historical SAGD dilbit GHG intensity, 2009–18**




Source: IHS Markit © 2020 IHS Markit

11. Facilities in ramp-up are typically removed from the distributions and IHS Markit estimate of range as they tend to have a high intensity and lower production volume; however, if operations persist after what would be considered normal ramp-up they would be included.

Figure 2), we find emission intensity would have declined by 19%, or 12 $kgCO_2e/bbl$, over this same period.[12] This point underscores the importance of understanding emission boundaries or which emissions are included in an estimate.

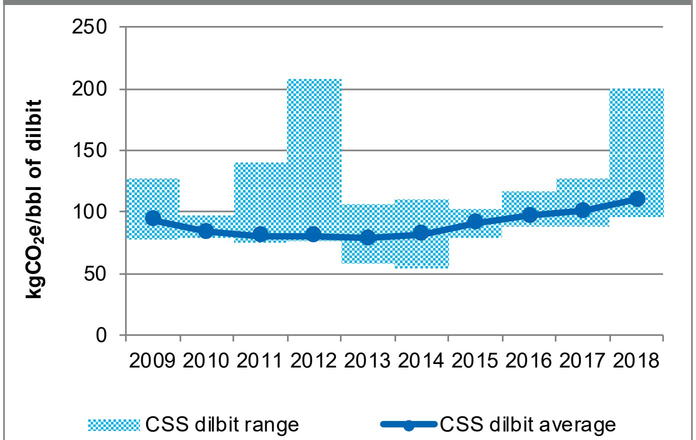
### CSS dilbit

CSS dilbit is the only form of oil sands extraction that has been on an upward emission intensity trend in recent years (see Figures 14 and 15). After the emissions intensity reached a low point in 2012, increasing volumes of steam, and thus natural gas, have been used per barrel of dilbit produced, leading to a rise in GHG emissions intensity. Over this same period, from 2012 to 2018, output also generally declined.

The average intensity of CSS dilbit increased 9%, or 9 $kgCO_2e/bbl$, from 2017 to 2018 to reach 110 $kgCO_2e/bbl$. CSS dilbit output is highly consolidated with only three existing operations, and more than 90% of output coming from the two largest ones. In recent years, the smaller of the three operations has had the greatest rise in GHG emission intensity, and despite being a highly consolidated sector the variability across CSS operations has increased considerably. This result is visible in Figures 14 and 15. In 2018, the range of CSS dilbit spanned from 96 $kgCO_2e/bbl$ to 201 $kgCO_2e/bbl$. The top end of the CSS range of 201 $kgCO_2e/bbl$ was also the upper bound across all oil sands operations.

Figure 14

Historical GHG intensity of CSS dilbit, 2009–18

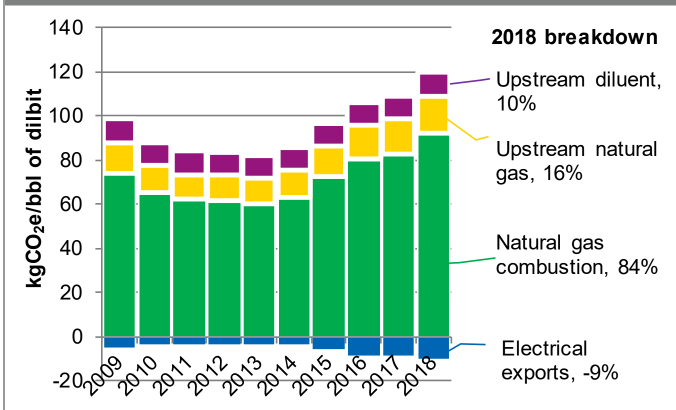



Source: IHS Markit



Figure 15

Composition of historical CSS dilbit GHG intensity, 2009–18




Source: IHS Markit



IHS Markit does not expect CSS dilbit to materially grow in the future, and the current rise in emission intensity has the potential to moderate in the near term. The recent upward trend in emissions intensity may be a result of the combination of the maturity in both producing wells and CSS operations. The most productive period of any well is early in its operation. As oil is recovered from a given reservoir, recovery rates tend to decline or require more work to maintain. This result puts upward pressure on GHG emission intensity. Eventually, these wells will be retired and replaced with new wells to maintain output or mitigate production declines. The rate of this replacement may have been impacted by the lower price environment in recent years, and with fewer operations and less volume than SAGD, operational changes may be more apparent. Longer term, it remains to be seen how the most recent price collapse of 2020 may impact upstream investment in CSS and future GHG emissions intensity.

12. Estimate is based on barrel of bitumen basis, on a per barrel of dilbit basis.

## Comparability and consistency—Playing with boundary conditions

There is uncertainty associated with estimating the GHG intensity of crude oil. Uncertainty can lead to reliability issues and differences in emissions boundaries (which emissions are included), which can lead to differences between estimates and studies. This section compares the current IHS Markit analysis with our prior work as well as with Canada's NIR, which makes use of different boundary conditions. Also included is the IHS Markit estimate of absolute oil sands emissions subject to the Alberta oil sands emissions limit (100 megatonne [MT] cap) and an update of the full life-cycle GHG emissions intensity of key oil sands production streams.

### IHS Markit estimates are consistent with prior work

IHS Markit has conducted several studies about the GHG intensity of Canadian oil sands. This report makes use of the same general assumptions as our prior IHS Markit (2018), including the same base models. Although some new information became available, notably the GHG emissions intensity of SAGD and CSS cogeneration, the latest IHS Markit report's finding ranged on average within 4% compared with that in our prior analysis. Table 1 provides a high-level comparison of the two studies' primary results.

Table 1

**IHS Markit (2020) and IHS Markit (2018) industry weighted average oil sands intensity compared***
($kgCO_2e$/bbl of product)

| Source | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| IHS Markit (2018) | 89 | 84 | 79 | 81 | 79 | 76 | 73 | 70 | 70 | *67*** |
| IHS Markit (2020) | 88 | 86 | 82 | 83 | 80 | 77 | 74 | 72 | 72 | 70 |
| **Total** | **-1%** | **1%** | **4%** | **3%** | **2%** | **2%** | **2%** | **4%** | **2%** | **4%** |

*Includes primary, experimental, and EOR operations not modeled in this analysis. **IHS Markit (2018) estimate for 2018 was a projection as opposed to an actualized estimate based on operating data.

Source: IHS Markit



The sources of discrepancies between the two studies are associated with changes to estimates of SAGD, CSS, and mined dilbit (PFT). Both thermal operations' (SAGD and CSS) emissions intensities were impacted by additional cogeneration performance data from Alberta Environment and Parks. This outcome resulted in a modest increase in our estimate of the GHG intensity of SAGD and CSS from 2015 to 2018. It also contributed to a small reduction in the GHG intensity of CSS dilbit for 2009 to 2011. Updates to mined dilbit (PFT) output and changes in our blend rate (dilute requirement per barrel of bitumen) assumption reduced our estimate of the historical GHG emission intensity compared with that in our prior analysis. A minor error was also found in our estimation of upstream GHG emission intensity for natural gas use for all mining projects. This did not have a material impact on the results.

The largest source of the difference shown in Table 1, however, was a result of a change in the modeling of CSS dilbit.[13] Alignment issues were discovered in the rate of year-on-year intensity change and year-on-year change in steam demand for CSS dilbit. The prior approach relied in part on the steam intensity relationship of SAGD adjusted to CSS steam demand. In this report, the CSS dilbit relationship to SAGD was severed and modeled separately.[14] The change resulted in an upward revision in the GHG intensity of CSS dilbit for 2010–17.

13. If CSS dilbit is removed from the weighted average comparison, shown in Table 1, the difference over the study period falls to 1%.

14. Because CSS dilbit was not part of the forecast emissions intensity in the prior IHS Markit analysis, the modeling approach relied on some simplifications compared with the approach taken in modeling SAGD. Changes in CSS steam demand were estimated based on estimated energy intensity of SAGD adjusted for CSS steam intensity. This approach to CSS in the prior report was believed to be equivalent, but rounding issues appear to have contributed to some misalignment.

The net impact of these changes resulted in a modestly lower GHG intensity estimate in 2009 and a modestly higher GHG intensity estimate in the latter years in the study period compared with that in our prior analysis. Appendix B provides a more detailed discussion of differences between the studies.

## IHS Markit estimates within 3% of the Canada's National Inventory Report

When it comes to GHG emissions, Canada's NIR prepared by the ECCC is regarded by many as the gold standard for Canadian emissions. The NIR provides annual absolute estimates of Scope 1 or direct emissions of key sectors, including upstream oil and gas and oil sands. These estimates differ from IHS Markit intensity estimates, which include a wider scope of emissions. Figure 2 at the beginning of this report provides a visual comparison of the differences in emissions boundary conditions between IHS Markit analysis and Canada's NIR.

IHS Markit, however, was able to make an apple-to-apple comparison of our estimates to the ECCC NIR. First, IHS Markit emission boundaries were adjusted to include only on-site direct emissions and then multiplied by annual production volumes to obtain absolute annual emission estimates. The NIR estimate was then adjusted by removing emissions associated with oil sands upgrading in Saskatchewan and the North West Redwater (NWR) refinery, which IHS Markit understands to be included as part of the ECCC NIR assessment of oil sands upgrading emissions. Both facilities are not included in the IHS Markit estimate. The NIR provides an estimate of Saskatchewan oil sands upgrading emissions, which we removed from total oil sands emissions reported in the NIR. Emissions associated with NWR for 2017 and 2018 were also removed from the NIR total using data from Canada's large facilities emitters database.[15]

After normalizing both the NIR emissions scope and IHS Markit emission boundaries, a comparison can be made, which is shown in Table 2. The results show that despite independent modeling approaches, IHS Markit estimates were on average over the past five years within 1% to those of the NIR. However, a more detailed comparison does reveal greater differences at individual production technology streams, particularly in 2016. It is our view that these discrepancies are within a reasonable error given the different modeling approaches. For more information, see Appendix B.

Table 2

**Comparison of IHS Markit absolute oil sands emissions to Canada's NIR (adjusted)***
($MMtCO_2e$)

| Source | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| **National Inventory Report (adjusted)*** | **68** | **72** | **71** | **77** | **80** |
| Mining and upgrading (adjusted)* | 39 | 39 | 36 | 39 | 39 |
| In situ | 29 | 33 | 35 | 38 | 41 |
| **IHS Markit (2020)** | **69** | **71** | **71** | **77** | **80** |
| Mining and upgrading | 37 | 35 | 31 | 35 | 36 |
| In situ | 32 | 36 | 40 | 42 | 43 |
| **Total** | **2%** | **0%** | **-1%** | **1%** | **-1%** |

*IHS Markit assessment did not include emissions associated with Husky Bi-Provincial Upgrader (BPU) located in Saskatchewan and the North West Redwater (NWR) Partnership Sturgeon refinery. The NIR (2020) assessment for oil sands mining and upgrading emissions shown here in Table 2 was adjusted by deducting the NIR (2020) assessment of Saskatchewan upgrading, which was assumed to be BPU, and by deducting reported emissions for the Sturgeon refinery from the ECCC large emitters database for 2017 and 2018.

Source: IHS Markit, ECCC NIR: Greenhouse Gas Sources and Sinks in Canada 1990–2018 (NIR 2020), ECCC: Greenhouse Gas Emissions from Large Facilities, 2019 and 2020



15. IHS Markit understands that Canada's NIR includes emissions from the Husky Energy Bi-Provincial Upgrader (BPU) in Saskatchewan as part of oil sands upgrader emissions, along with emissions from the NWR refinery. The BPU is not included in the IHS Markit analysis because it is not dedicated to upgrading oil sands bitumen as it also processes other non–oil sands–derived heavy crude oil. The NIR estimates of the Saskatchewan oil sands upgrader were removed from the NIR totals shown in Table 2 . This would be similar to using Alberta oil sands totals found in the NIR. In addition, NWR is also not part of the IHS Markit analysis as it is designed to market refined products. IHS Markit removed emissions associated with NWR using the ECCC Greenhouse Gas Emissions from Large Facilities database for 2017 and 2018. Please see "Greenhouse gas emissions from large facilities," Government of Canada, https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions/large-facilities.html, retrieved 1 June 2020.

## Understanding Alberta's 100 MT oil sands cap

A good example of the importance of understanding emissions boundaries in GHG estimation is in discussions involving the Oil Sands Emissions Limit Act announced in 2016. The act would limit absolute oil sands emissions in Alberta to 100 MT. This is also known colloquially as the "100 MT cap."

The 100 MT cap includes a distinct definition of which emissions are subject to or included as part of the emissions cap, differing from the definition in Canada's NIR. Under the 100 MT cap, emissions associated with electrical power generation and use; emissions arising from primary, experimental, and EOR crude oil production (occurring within the oil sands region); and emissions associated with upgraders that start up after 2015 are excluded.[16] As a result of these differences, emissions subject to the cap are lower than those found in the NIR.

In 2018, IHS Markit estimates this difference adds up to more than 13 $MMtCO_2e$—about 9 MT associated with electrical power generation and use; 2 MT associated with "new upgrading"; and nearly 3 MT associated with primary, experimental, and EOR extraction. A comparison of the IHS Markit estimate of direct oil sands emissions consistent with Canada's NIR and emissions subject to the 100 MT cap over the past five years is shown in Table 3.

## Putting IHS Markit analysis on a full life-cycle basis

The latest IHS Markit analysis focuses on upstream GHG emissions associated with oil sands extraction and primary processing (i.e., upgrading). However, an estimate of the full life-cycle GHG intensity—from extraction to combustion—was completed to allow for comparison with prior IHS Markit work.

Table 3

**Comparison of absolute direct oil sands emissions by year and emissions included in 100 MT**
($MMtCO_2e$)

| Source | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| Direct boundary | 69 | 71 | 71 | 77 | 80 |
| 100 MT cap | 56 | 57 | 58 | 63 | 66 |
| **Difference** | **13** | **14** | **13** | **14** | **13** |

Source: IHS Markit © 2020 IHS Markit

IHS Markit made use of its prior analysis for downstream processing, transportation, and combustion emissions to complete the estimate with the exception of mined dilbit (PFT).[17] IHS Markit undertook a new estimate for the downstream (or refining) GHG emission intensity associated with processing mined dilbit (PFT) because the prior estimate from 2014 assumed a crude assay similar to SAGD dilbit. Mined dilbit (PFT) has lower asphaltenes and a lower blending requirement (volume of diluent required to meet pipeline specification) and, as a result, a different downstream GHG emission intensity. This work revised the refining emission intensity for mined dilbit (PFT) from the prior assumption of 70 $kgCO_2e$/bbl of refined product to 55 $kgCO_2e$/bbl of refined product. The full life-cycle GHG emissions intensity of mined dilbit (PFT) was reassessed at 1.6% below the US average in 2018.[18] For more information on the downstream mined dilbit (PFT) GHG emissions estimation, see Appendix B.

Figure 16 depicts the average intensity of major production streams compared with our prior estimates and the average intensity of crude oil refined in the United States. Inclusive of the minimum and maximum of operations (shown with purple dots in Figure 16), IHS Markit found the average life-cycle intensity of the Canadian oil sands in 2018 to range from 1.6% below the US average to 19% above—the greatest variation to date. Note CSS is not included in Figure 16 as it represents a limited share of total production.

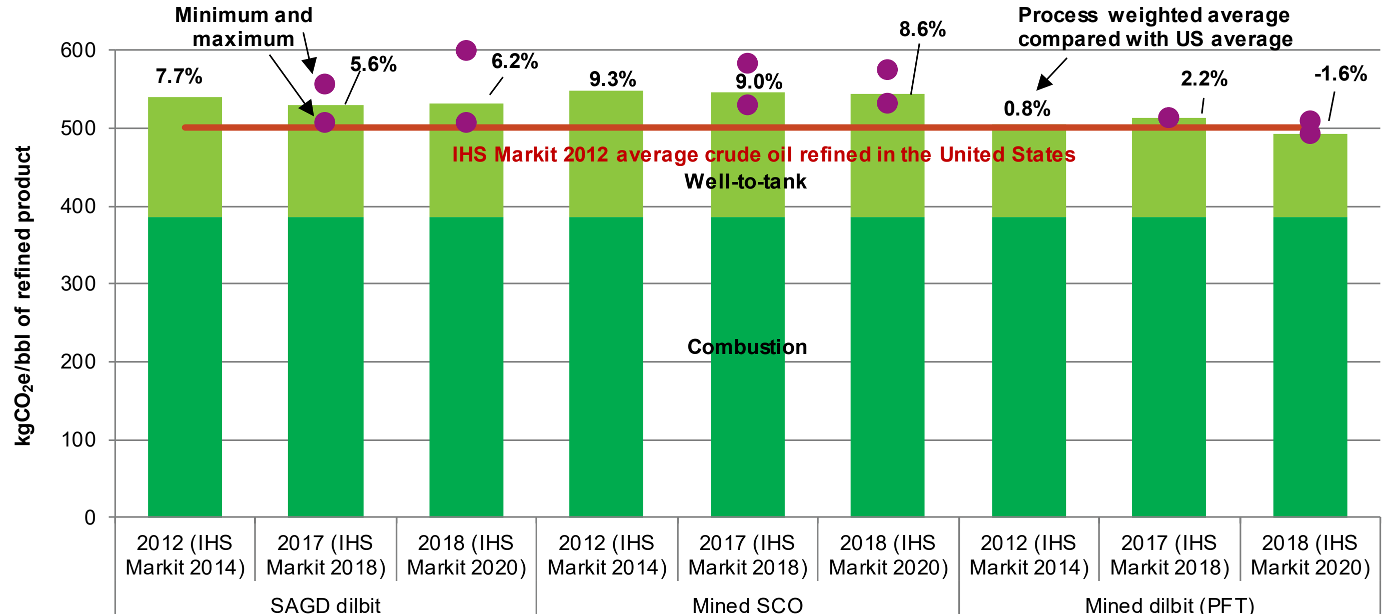
16. *Oil Sands Emissions Limit Act,* Province of Alberta, https://www.qp.alberta.ca/documents/Acts/O07p5.pdf, retrieved 17 April 2020.

17. Prior transportation through combustion estimates were derived from the IHS Markit Strategic Report (2014) *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*.

18. The US average is an estimate derived from the IHS Markit 2014 Strategic Report IHS *Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil,* which estimated the life-cycle GHG intensity of crude oil refined and processed in the United States in 2012. For more information, see www.ihsmarkit.com/oilsandsdialogue.

Figure 16

**Oil sands life-cycle GHG emissions cases compared**




Note: The full life-cycle GHG emission intensity estimate for 2012 (IHS Markit 2014) is sourced from the IHS Markit Strategic Report (2014) *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*. Upstream estimates for 2017 (IHS Markit 2018) are sourced from the IHS Markit Strategic Report (2018) *Greenhouse gas intensity of oil sands production: Today and in the future*. Upstream estimate for 2018 (IHS Markit 2020) is published in this report. Estimates of downstream SAGD dilbit and SCO emissions for all estimates are derived from (IHS Markit 2014).
Source: IHS Markit



It should be noted that IHS Markit has included a comparison of life-cycle GHG emission intensity from various studies over time, and caution should be advised in drawing conclusions about sources of change on that basis. Differences in the estimation methods used in this analysis and the previous IHS Markit assessment may contribute to differences in the results from study to study.

## Concluding remarks

At the time of the release of this report, the world and the global oil market were still amid the global pandemic of 2020 and the greatest economic shock the world has seen in more than a generation. In a time of increased uncertainty, a greater array of alternative futures can seem plausible. However, the importance of climate change and decarbonization appears set to remain a key policy priority. Indeed, many governments are discussing targeting economic recovery stimulus to accelerate energy transition. Still, the ubiquitous nature of oil and gas is likely to ensure it continues to make significant contributions to meeting global energy demand for the foreseeable future. Oil and gas, however, will not be immune to global pressures to decarbonize, and the importance of understanding GHG emissions from production to end use will rise.

The Canadian oil sands is one of the most studied resources in the world, and yet we continue to learn more about their GHG emissions and the drivers of emission intensity reductions. For example, in this report we found that the GHG emission intensity of the Canadian oil sands has continued to decline as new lower GHG emission intensity forms of production increased output and as legacy mining operations experienced intensity improvement. Meanwhile, an improved understanding of downstream emission intensity associated with newer forms of oil sands production reduced the IHS Markit estimate of the lower bound of the range of life-cycle GHG emissions to 1.6% beneath the US average (the lowest to date).[19]

19. The US average is the average life-cycle GHG intensity of crude oil refined or processed in the United States in 2012, as reported in the IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*.

Although 2018 set a new low in the average upstream GHG intensity of Canadian oil sands production, efforts to decarbonize upstream oil production are increasing. If upstream operations are increasingly going to be asked to compete on GHG emissions intensity, the Canadian oil sands industry may have to accelerate its efforts to maintain its place in global supply.

# Appendix A: Detail result tables

Table A-1

## Oil sands GHG emissions intensity summary results

| | | History | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Units | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Percent change, 2009–18 | Percent change, 2017–18 |
| CSS | kgCO₂e/bbl of dilbit | n/a | 94 | 84 | 81 | 80 | 78 | 82 | 91 | 97 | 101 | 110 | 18% | 9% |
| SAGD | kgCO₂e/bbl of dilbit | n/a | 66 | 64 | 64 | 65 | 65 | 62 | 64 | 66 | 64 | 65 | -1% | 2% |
| **In situ average** | **kgCO₂e/bbl of dilbit** | **n/a** | **79** | **73** | **71** | **71** | **69** | **67** | **71** | **72** | **71** | **73** | **-8%** | **2%** |
| Mined SCO | kgCO₂e/bbl of SCO | 112 | 116 | 109 | 104 | 110 | 106 | 105 | 98 | 92 | 91 | 89 | -24% | -3% |
| Mined dilbit | kgCO₂e/bbl of dilbit | - | - | - | - | - | 86 | 52 | 45 | 45 | 47 | 41 | n/a | -12% |
| **Mining average** | **kgCO₂e/bbl of product** | **112** | **116** | **109** | **104** | **110** | **105** | **100** | **88** | **82** | **82** | **75** | **-36%** | **-10%** |
| **Average (of shown)** | **kgCO₂e/bbl of product** | **n/a** | **100** | **91** | **88** | **89** | **86** | **82** | **78** | **77** | **76** | **74** | **-26%** | **-3%** |
| | **Share of supply** | **0%** | **84%** | **86%** | **86%** | **85%** | **85%** | **86%** | **88%** | **90%** | **92%** | **93%** | | |
| **Average (including primary and experimental)** | **kgCO₂e/bbl of product** | **n/a** | **88** | **86** | **82** | **83** | **80** | **77** | **74** | **72** | **72** | **70** | **-20%** | **-2%** |
| | **Share of supply** | **0%** | **84%** | **84%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | **100%** | | |

Source: IHS Markit



Table A-2

## Mined oil sands emissions intensity by process and component

| | | History | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Units | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Percent change, 2009–18 | Percent change, 2017–18 |
| **Mined SCO** | | | | | | | | | | | | | | |
| Natural gas | kgCO₂e/bbl of SCO | 41 | 41 | 38 | 35 | 45 | 38 | 40 | 38 | 38 | 38 | 38 | -8% | -1% |
| Process gas | kgCO₂e/bbl of SCO | 29 | 32 | 31 | 31 | 25 | 34 | 33 | 27 | 24 | 23 | 22 | -31% | -6% |
| Petroleum coke | kgCO₂e/bbl of SCO | 20 | 21 | 17 | 16 | 13 | 10 | 11 | 11 | 10 | 10 | 9 | -56% | -8% |
| Mobile mine fleet | kgCO₂e/bbl of SCO | 9 | 9 | 10 | 9 | 9 | 8 | 9 | 9 | 8 | 8 | 8 | -6% | 0% |
| Fugitive, venting, and flaring | kgCO₂e/bbl of SCO | 9 | 8 | 8 | 8 | 10 | 9 | 6 | 6 | 6 | 6 | 6 | -28% | 2% |
| Carbon capture | kgCO₂e/bbl of SCO | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1 | -3 | -2 | -2 | | -7% |
| **Direct emissions (within plant gate)** | **kgCO₂e/bbl of SCO** | **108** | **111** | **104** | **99** | **102** | **99** | **98** | **90** | **84** | **83** | **81** | **-27%** | **-2%** |
| Electrical balance (import/export) | kgCO₂e/bbl of SCO | -4 | -3 | -2 | -1 | 0 | -1 | 0 | 1 | 1 | 1 | 1 | -129% | -27% |
| Upstream natural gas production | kgCO₂e/bbl of SCO | 8 | 8 | 7 | 7 | 8 | 7 | 8 | 7 | 7 | 7 | 7 | -8% | -1% |
| Upstream diluent | kgCO₂e/bbl of SCO | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| **IHS Markit upstream life-cycle basis** | **kgCO₂e/bbl of SCO** | **112** | **116** | **109** | **104** | **110** | **106** | **105** | **98** | **92** | **91** | **89** | **-24%** | **-3%** |
| **Mined dilbit (PFT)** | | | | | | | | | | | | | | |
| Natural gas | kgCO₂e/bbl of dilbit | - | - | - | - | - | 43 | 25 | 23 | 22 | 24 | 21 | | -11% |
| Process gas | kgCO₂e/bbl of dilbit | - | - | - | - | - | - | - | - | - | - | - | | |
| Petroleum coke | kgCO₂e/bbl of dilbit | - | - | - | - | - | - | - | - | - | - | - | | |
| Mobile mine fleet | kgCO₂e/bbl of dilbit | - | - | - | - | - | 9 | 5 | 5 | 5 | 5 | 6 | | 26% |
| Fugitive, venting, and flaring | kgCO₂e/bbl of dilbit | - | - | - | - | - | 7 | 3 | 1 | 1 | 1 | 1 | | -14% |
| Carbon capture | kgCO₂e/bbl of dilbit | - | - | - | - | - | - | - | - | - | - | - | | |
| **Direct emissions (within plant gate)** | **kgCO₂e/bbl of dilbit** | **-** | **-** | **-** | **-** | **-** | **58** | **33** | **29** | **28** | **30** | **28** | | **-5%** |
| Electrical balance (import/export) | kgCO₂e/bbl of dilbit | - | - | - | - | - | 11 | 7 | 4 | 4 | 4 | 1 | | -85% |
| Upstream natural gas production | kgCO₂e/bbl of dilbit | - | - | - | - | - | 8 | 5 | 4 | 4 | 4 | 4 | | -11% |
| Upstream diluent | kgCO₂e/bbl of dilbit | - | - | - | - | - | 8 | 8 | 8 | 8 | 8 | 8 | | |
| **IHS Markit upstream life-cycle basis** | **kgCO₂e/bbl of dilbit** | **-** | **-** | **-** | **-** | **-** | **86** | **52** | **45** | **45** | **47** | **41** | | **-12%** |

Table A-2

## Mined oil sands emissions intensity by process and component (continued)

| | Units | History 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Percent change, 2009–18 | Percent change, 2017–18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Mined average** | **Units** | | | | | | | | | | | | | |
| Natural gas | kg$CO_2$e/bbl of product | 41 | 41 | 38 | 35 | 45 | 38 | 39 | 35 | 35 | 35 | 33 | -20% | -7% |
| Process gas | kg$CO_2$e/bbl of product | 29 | 32 | 31 | 31 | 25 | 32 | 30 | 22 | 19 | 19 | 15 | -52% | -18% |
| Petroleum coke | kg$CO_2$e/bbl of product | 20 | 21 | 17 | 16 | 13 | 10 | 10 | 9 | 8 | 8 | 6 | -69% | -20% |
| Mobile mine fleet | kg$CO_2$e/bbl of product | 9 | 9 | 10 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | -13% | 1% |
| Fugitive, venting, and flaring | kg$CO_2$e/bbl of product | 9 | 8 | 8 | 8 | 10 | 8 | 6 | 5 | 5 | 5 | 4 | -46% | -9% |
| Carbon capture | kg$CO_2$e/bbl of product | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -1 | -2 | -2 | -2 | | -19% |
| **Direct emissions (within plant gate)** | **kg$CO_2$e/bbl of product** | **108** | **111** | **104** | **99** | **102** | **98** | **92** | **78** | **73** | **73** | **65** | **-41%** | **-10%** |
| Electrical balance (import/export) | kg$CO_2$e/bbl of product | -4 | -3 | -2 | -1 | 0 | 0 | 0 | 1 | 2 | 2 | 1 | -127% | -57% |
| Upstream natural gas production | kg$CO_2$e/bbl of product | 8 | 8 | 7 | 7 | 8 | 7 | 7 | 7 | 7 | 7 | 6 | -20% | -7% |
| Upstream diluent | kg$CO_2$e/bbl of product | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 2 | 2 | 3 | | 53% |
| **IHS Markit upstream life-cycle basis** | **kg$CO_2$e/bbl of product** | **112** | **116** | **109** | **104** | **110** | **105** | **100** | **88** | **82** | **82** | **75** | **-36%** | **-10%** |

Source: IHS Markit 

Table A-3

## Oil sands SAGD dilbit historical GHG emission intensity, 2009–18

| Component | Units | History 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Percent change, 2009–18 | Percent change, 2017–18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural gas | kg$CO_2$e/bbl of dilbit | 63 | 58 | 56 | 56 | 56 | 51 | 51 | 52 | 50 | 51 | -19% | 1% |
| Flaring and fugitives | kg$CO_2$e/bbl of dilbit | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0% | 0% |
| **Direct emissions (within plant gate)** | **kg$CO_2$e/bbl of dilbit** | **63** | **58** | **56** | **56** | **56** | **51** | **52** | **53** | **50** | **51** | **-19%** | **1%** |
| Electrical import/export | kg$CO_2$e/bbl of dilbit | -19 | -15 | -13 | -11 | -12 | -9 | -8 | -7 | -6 | -5 | -72% | -7% |
| Upstream natural gas production | kg$CO_2$e/bbl of dilbit | 12 | 11 | 10 | 10 | 10 | 10 | 10 | 10 | 9 | 9 | -19% | 1% |
| Upstream diluent production | kg$CO_2$e/bbl of dilbit | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 0% | 0% |
| **IHS Markit upstream life-cycle basis** | **kg$CO_2$e/bbl of dilbit** | **66** | **64** | **64** | **65** | **65** | **62** | **64** | **66** | **64** | **65** | **-1%** | **2%** |

Source: IHS Markit 

Table A-4

## Oil sands CSS dilbit historical GHG emission intensity, 2009–18

| Component | Units | History 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Percent change, 2009–18 | Percent change, 2017–18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural gas | kg$CO_2$e/bbl of dilbit | 74 | 65 | 62 | 61 | 60 | 63 | 72 | 80 | 83 | 92 | 25% | 11% |
| Flaring and fugitives | kg$CO_2$e/bbl of dilbit | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0% | 0% |
| **Direct emissions (within plant gate)** | **kg$CO_2$e/bbl of dilbit** | **74** | **65** | **62** | **62** | **60** | **63** | **73** | **81** | **83** | **92** | **24%** | **11%** |
| Electrical import/export | kg$CO_2$e/bbl of dilbit | -5 | -4 | -4 | -3 | -4 | -4 | -6 | -9 | -9 | -10 | 105% | 18% |
| Upstream natural gas production | kg$CO_2$e/bbl of dilbit | 14 | 12 | 12 | 12 | 11 | 12 | 14 | 15 | 16 | 17 | 25% | 11% |
| Upstream diluent production | kg$CO_2$e/bbl of dilbit | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 0% | 0% |
| **IHS Markit upstream life-cycle basis** | **kg$CO_2$e/bbl of dilbit** | **94** | **84** | **81** | **80** | **78** | **82** | **91** | **97** | **101** | **110** | **18%** | **9%** |

Source: IHS Markit 

# Appendix B: Notes of comparison to prior analysis

This study refreshes and extends the historical oil sands GHG emission estimates first made in the IHS Markit report titled *Greenhouse gas emissions intensity of Canadian oil sands production: Past and in the future* released in 2018. The underlying models, method, and assumptions used for our prior study were deployed in this analysis. Despite the incorporation of some new data, changes to CSS dilbit modeling and a reestimation of the average intensity over the entire study period remained relatively consistent with that in the prior study. However, differences do exist and are more pronounced at the individual production stream level. Changes in our modeling approach impacted estimates for SAGD dilbit, CSS dilbit, and mined dilbit (PFT).

This appendix provides a detailed comparison between this study's results and IHS Markit (2018). For detailed information on our original methodology, please see IHS Markit (2018). Table B-1 provides a comparison between our current results and the IHS Markit (2018) results. What follows are several sections documenting major changes or updates in this most recent analysis compared with our prior 2018 report.

Table B-1

**Detailed comparison of IHS Markit (2020) and IHS Markit (2018) analysis**

| | | | History | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Category** | **Source** | **Units** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018**** | **Percent change, 2009–18** | **Percent change, 2017–18** |
| **Weighted average*** | IHS Markit (2018) | $kgCO_2e$/bbl of product | 89 | 84 | 79 | 81 | 79 | 76 | 73 | 70 | 70 | 67 | -24% | -4% |
| | IHS Markit (2020) | $kgCO_2e$/bbl of product | 88 | 86 | 82 | 83 | 80 | 77 | 74 | 72 | 72 | 70 | -20% | -2% |
| *Difference* | | | *-1%* | *1%* | *4%* | *3%* | *2%* | *2%* | *2%* | *4%* | *2%* | *4%* | | |
| **Mined SCO** | IHS Markit (2018) | $kgCO_2e$/bbl of SCO | 115 | 108 | 104 | 110 | 105 | 105 | 97 | 92 | 91 | 88 | -24% | -4% |
| | IHS Markit (2020) | $kgCO_2e$/bbl of SCO | 116 | 109 | 104 | 110 | 106 | 105 | 98 | 92 | 91 | 89 | -24% | -3% |
| *Difference* | | | *1%* | *1%* | *1%* | *0%* | *0%* | *0%* | *0%* | *0%* | *0%* | *1%* | | |
| **Mined dilbit (PFT)** | IHS Markit (2018) | $kgCO_2e$/bbl of dilbit | 0 | 0 | 0 | 0 | 98 | 57 | 48 | 47 | 46 | 45 | n/a | -1% |
| | IHS Markit (2020) | $kgCO_2e$/bbl of dilbit | 0 | 0 | 0 | 0 | 86 | 52 | 45 | 45 | 47 | 41 | n/a | -14% |
| *Difference* | | | *0%* | *0%* | *0%* | *0%* | *-12%* | *-7%* | *-6%* | *-4%* | *3%* | *-9%* | | |
| **SAGD dilbit** | IHS Markit (2018) | $kgCO_2e$/bbl of dilbit | 66 | 63 | 64 | 65 | 65 | 62 | 62 | 64 | 63 | 62 | -6% | -1% |
| | IHS Markit (2020) | $kgCO_2e$/bbl of dilbit | 66 | 64 | 64 | 65 | 65 | 62 | 64 | 66 | 64 | 65 | -1% | 2% |
| *Difference* | | | *1%* | *1%* | *1%* | *1%* | *1%* | *0%* | *3%* | *3%* | *2%* | *6%* | | |
| **CSS dilbit** | IHS Markit (2018) | $kgCO_2e$/bbl of dilbit | 96 | 77 | 69 | 68 | 71 | 73 | 76 | 89 | 90 | n/a | n/a | n/a |
| | IHS Markit (2020) | $kgCO_2e$/bbl of dilbit | 94 | 84 | 81 | 80 | 78 | 82 | 91 | 97 | 101 | 110 | 18% | 9% |
| *Difference* | | | *-3%* | *10%* | *17%* | *19%* | *11%* | *12%* | *20%* | *9%* | *12%* | *n/a* | | |

Note: Estimates shown for IHS Markit (2018) for 2018 calendar year were projections and not based on historical data. *Includes primary, experimental, and EOR operations not modeled in this analysis. GHG emission intensity estimate for these additional forms of oil sands extraction was extrapolated from existing IHS Markit research and remained unchanged from IHS Markit (2018). **Estimate for 2018 from IHS Markit (2018) was part of forecast emissions, and the basis of estimation was fundamentally different. No forecast of CSS dilbit was completed for IHS Markit (2018).

Source: IHS Markit



# Study period extension to include 2018

In the current study, IHS Markit was able to incorporate an additional year of operational data for oil sands facilities to extend the historical outlook to include 2018. Thermal in situ operational data were updated, consistent with prior report, based on the Alberta Energy Regulator (AER) report ST53: Alberta In Situ Oil

Sands Production Summary.[20] Mining data were sourced from the AER report ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement.[21]

## Expanded thermal cogeneration intensity data

The IHS Markit estimate of the GHG emissions associated with thermal in situ extraction—SAGD and CSS—is affected by the GHG emissions intensity of cogeneration. In our prior analysis, estimates of the GHG intensity of cogeneration were made using data obtained upon request from Alberta Environment and Parks. Alberta's Specified Gas Emitters Regulation (SGER) collected data on cogeneration emissions, which IHS Markit was able to access to estimate the GHG emissions intensity of cogeneration by year ($kgCO_2e/MWh$). In IHS Markit (2018), estimates of 2013 and 2014 were made based on Alberta's SGER database. The 2014 estimate (786 $kgCO_2e/MWh$) was used for both SAGD and CSS and extrapolated over the entire study period.

In this current analysis, IHS Markit was able to obtain three additional years of cogeneration data from Alberta Environment and Parks, increasing the data set to 2013–17. As a result of the expanded coverage, the constant GHG cogeneration intensity estimate was replaced with corresponding annual estimates for 2013–17. For 2009–12, the 2013 estimate was used, and for 2018, data from 2017 were used.

Although the GHG emission intensity of cogeneration fluctuated by year, it was on average from 2013 to 2017 higher than the 2014 value used throughout our prior study (averaging 836 $kgCO_2e/MWh$). The change in cogeneration intensity was the primary driver behind the differences in SAGD dilbit and contributed to some variation in CSS dilbit visible in Table B-1. In IHS Markit (2018), 2018 was a projection and not based on historical data; however, the 2018 projection was nonetheless impacted by the prior cogeneration intensity estimate. The primary factor behind the difference between the projected SAGD dilbit GHG estimate in 2018 was moderately higher SOR compared with that of 2017 than IHS Markit had modeled for 2018.

## Change to CSS dilbit estimation

IHS Markit updated its approach to modeling CSS dilbit to perfectly align with SAGD. In our prior analysis, because CSS dilbit is a comparatively smaller source of oil sands supply and not anticipated to grow materially in the IHS Markit outlook, the future emission intensity was not forecast in our prior 2018 report. As a result, estimated thermal energy demand relied on SAGD thermal energy intensity adjusted for CSS stream demand and output. Alignment issues between the rate of change in the CSS SOR and the IHS Markit intensity estimate for CSS dilbit resulted in the removal of the dependence on SAGD relationships. This change resulted in an upward revision to our estimate of CSS dilbit for 2010–17 to varying degrees. If CSS dilbit is removed from the weighted average comparison, shown in Table 1, the difference between study estimates falls to 1%.

### Mined dilbit (PFT) production

The IHS Markit (2018) estimate of mined dilbit (PFT) GHG emission intensity made use of bitumen delivereies as reported in ST39 converted to a dilbit basis as the denominator in the emissions intensity calculation. We decided in this analysis to make use of bitumen production to better reflect actual throughput or output of ongoing operations and better align with SCO production used to estimate GHG intensity from mined SCO facilities. This change reduced the GHG emission intensity during the ramp-up of the Imperial Kearl operation

20. "ST53: Alberta In Situ Oil Sands Production Summary," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53.html, retrieved 17 April 2020.

21. "ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39.html, retrieved 17 April 2020.

compared with IHS Markit (2018) and contributed to changes in the estimated intensity of mined dilbit (PFT) visible in Table B-1.

## Mined dilbit (PFT) blending

IHS Markit estimates of emission intensity are presented on a marketed product basis to represent the intensity of a barrel of product being sold and align with prior and ongoing life-cycle assessments. SAGD, CSS, and mined dilbit (PFT) market diluted bitumen barrels. Mined dilbit (PFT) has been found to precipitate out some of the heavier components found in mined bitumen, resulting in a slightly lower-density bitumen. As a result, it requires less diluent per barrel compared with SAGD dilbit or CSS dilbit. In our prior IHS Markit (2018), we assumed a blend rate of 20% diluent to 80% bitumen for mined dilbit (PFT). We now believe a blend rate closer to 22% diluent and 78% bitumen may be more accurate and have adjusted our blend rate in the model. This development also contributed to changes shown in Table B-1 for mined dilbit (PFT).

## Mined dilbit (PFT) downstream emissions

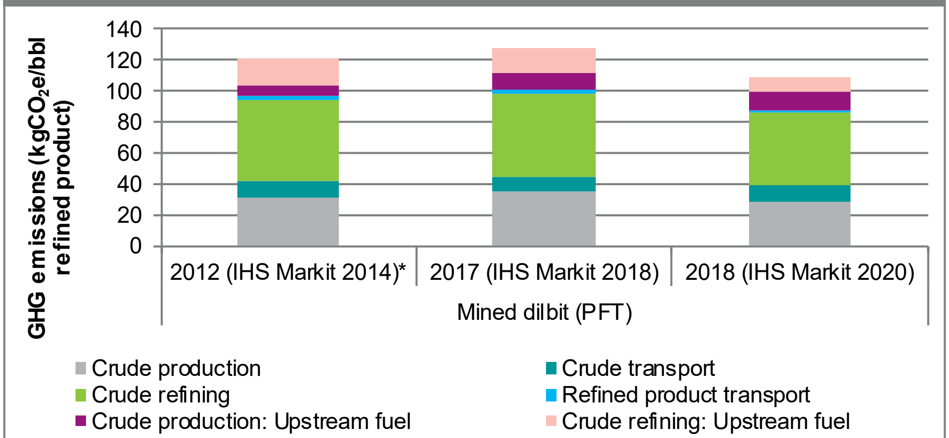
IHS Markit undertook a new estimate for the downstream GHG emissions associated with the refining of mined dilbit (PFT). IHS Markit made use of the open-source Petroleum Refinery Life Cycle Inventory Model (PRELIM) for this estimate.[22] PRELIM is a Microsoft Excel–based tool that estimates the energy use and GHG emissions, among a variety of other parameters, associated with processing crude oil in a range of refinery configurations. There is crude assay information preloaded in PRELIM (149 crude assays in Version 1.3 at the time of this publication). IHS Markit used the crude assay available in PRELIM for Imperial's Kearl oil sands mined dilbit (PFT) operation, which can be found in the public model. IHS Markit chose to model a deep conversion coking refinery including a fluid catalytic cracker (FCC). PRELIM was run assuming that the refinery was processing 100% Kearl dilbit. In reality, refineries typically process a blend of various crudes at any given time.

This work resulted in a revised estimate of the downstream refining emission intensity for mined dilbit (PFT) of 55 kg$CO_2$e/bbl of refined product, which is lower than the previous estimate of 70 kg$CO_2$e/bbl of refined product. The results, on an energy basis, were confirmed with an internal IHS Markit refining model. A comparison of the well-to-tank GHG emissions associated with mined dilbit (PFT) as estimated by IHS Markit in our 2014 and 2018 reports is shown in Figure B-1.

A direct comparison of the estimates in Figure B-1 is difficult because of differences in the estimation methods.

Figure B-1

**IHS Markit estimates of well-to-tank GHG emissions for mined dilbit (PFT)**




Note: *The completion of the full life-cycle assessment for 2012 (IHS Markit 2014) is from the IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*. Upstream estimates for 2017 (IHS Markit 2018) are from the IHS Markit Strategic Report *Greenhouse gas intensity of oil sands production: Today and in the future*. Upstream estimate for 2018 (IHS Markit 2020) is published in this report. Estimates of downstream SAGD dilbit and SCO emissions for all estimates are derived from IHS Markit 2014.
Source: IHS Markit



22. PRELIM can be downloaded from the Life Cycle Assessment of Oil Sands Technologies research group (University of Calgary). Version 1.3 of PRELIM was used for this analysis.

Previous assessments of downstream emissions intensities were drawn from IHS Markit (2014). The IHS Markit (2014) report sourced the downstream estimates for refining of dilbit from a Jacobs Consultancy report prepared for the Alberta Petroleum Marketing Commission in 2012 titled "EU pathway study: life cycle assessment of crude oils in a European context" (Jacobs 2012). Downstream GHG emissions values from Jacobs (2012) were used to calculate an average value for refining dilbit (including direct refining emissions as well as emissions associated with upstream fuels used in refining). Mined dilbit (PFT) was treated the same as SAGD dilbit. Table B-2 is a comparison of the methods used for estimating downstream emissions of mined dilbit (PFT) for this study with those used in previous IHS Markit assessments.

Table B-2

**GHG estimation method comparison with previous IHS Markit assessments**

| Stage of life | IHS Markit, 2020 | IHS Markit, 2018 and 2014 |
|---|---|---|
| **Crude production: Upstream fuel** | Accounts for natural gas and imported electricity, based on ST39 data. | Accounts for natural gas and imported electricity, based on Jacobs model for extraction energy. |
| **Crude transport** | Value: 8.2 kg$CO_2$e/bbl refined product.<br>Estimate generated based on transport distance of 4,000 km by pipeline.<br>Refer to Table 3 for other assumptions. | Value: 10 kg$CO_2$e/bbl refined product.<br>Meta-analysis based on Jacobs (2012), Charpentier (2011), and CARB-OPGEE (2012). The value was generated by taking an average of the range of values cited. Estimates ranged from 3.5 to 34. |
| **Refining** | Value: 47 kg$CO_2$e/bbl refined product (FCC).<br>Model: PRELIM (Version 1.3).<br>Refinery configuration: FCC coking.<br>Key crude properties: API: 22.<br>Refinery yield: 1 bbl dilbit: 0.9 bbl fuels. | Value: 54 kg$CO_2$e/bbl refined product.<br>Models: Various including PetroPlan.<br>Refinery configuration: FCC coking.<br>Key crude properties: API: 21.<br>Refinery yield: 1 bbl dilbit: 1 bbl fuels. |
| **Refining: Upstream fuel** | Value: 9 kg$CO_2$e/bbl refined product (FCC).<br>Model: PRELIM.<br>Accounts for natural gas and imported electricity. | Value: 17 kg$CO_2$e/bbl refined product.<br>Model(s): Various including PetroPlan.<br>Accounts for natural gas, imported electricity, and isobutane. |

Note: See the IHS Markit Strategic Reports *Greenhouse gas intensity of oil sands production: Today and in the future* and *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil.*
CARB-OPGEE (2012): To support California's Low Carbon Fuel Standard, the California Air Resources Board (CARB) released draft carbon intensities for various crude oils consumed in California (posted 17 September 2012). Estimates were made using the Oil Production Greenhouse gas Emissions Estimator (OPGEE).
Charpentier (2011): Charpentier et al., "Life Cycle Greenhouse Gas Emissions of Current Oil Sands Technologies: GHOST Model Development and Illustrative Application," published July 2011.

Source: IHS Markit



IHS Markit believes that the recent estimates are more representative of downstream GHG emissions intensity for mined dilbit (PFT) than those from our previous assessments.

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An IHS CERA Special Report

# Growth in the Canadian Oil Sands:

*Finding the New Balance*

CERA

IHS Cambridge Energy Research Associates | CERA.com

# Growth in the Canadian Oil Sands: Finding the New Balance

An IHS CERA Special Report

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For clients with access to **CERA.com,** the following features related to this report may be available online: downloadable data (excel file format), downloadable, full-color graphics, author biographies, and the Adobe PDF version of the complete report.

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## WORKSHOP PARTICIPANTS

CERA hosted a series of workshops and meetings providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to oil sands development.

Workshops were held in Calgary (November 21, 2008); Washington, DC (December 10, 2008); Fort McMurray (January 14, 2009); and Calgary (March 24, 2009). Participation in these workshops does not in any way reflect endorsement of the content of this report. CERA is exclusively responsible for the content of this report.

CERA would like to thank and recognize the following organizations who made a contribution to this report by participating in one or more of the workshops:

- Alberta Energy Research Institute (AERI)
- Alberta Energy Resources Conservation Board (ERCB)
- American Petroleum Institute (API)
- Argonne National Laboratory
- Athabasca Oil Sands Corp.
- BP Canada
- Canadian Association of Petroleum Producers (CAPP)
- Canadian Natural Resources Limited
- Canadian Oil Sands Trust
- CanmetENERGY
- ConocoPhillips
- EnCana
- Government of Alberta
- Government of Saskatchewan
- IBM Canada
- Idaho National Laboratory
- Ivanhoe Energy
- Laricina Energy
- Marathon
- MEG Energy
- MP Fort McMurray-Athabasca
- Natural Resources Canada (NRCOM)
- Nexen Inc.
- OSUM Oil Sands
- Pembina Institute
- Petrobank Energy and Resources Ltd.
- Regional Municipality of Wood Buffalo
- Resources for the Future
- Securing America's Future Energy (SAFE)
- Seven Generations Energy
- Shell Canada Ltd.
- Suncor Energy Inc.
- TD Bank
- Total E&P Canada
- TransCanada
- US Environmental Protection Agency (EPA)
- US Department of Energy
- Urban Development Institute - Wood Buffalo
- Wood Buffalo Métis Corporation (WBMC)

## Report Objectives

Few natural resource developments offer such a large magnitude of potential benefits as the Canadian oil sands, the second largest reserves of recoverable oil in the world after Saudi Arabia, but development also raises significant long-term questions. This is reflected in the wide spectrum of views regarding the pace and future of oil sands development. Some argue for continued expansion, others for a slower pace or even halt to development. There are many stakeholders affected by oil sands development: local, provincial, and national governments; neighboring communities; investors; and nongovernmental organizations (NGOs).

The purpose of this CERA report is to offer a balanced assessment of the benefits, risks, and issues associated with oil sands development. This entails three specific objectives.

- **Inform.** We explain the history of the oil sands and its place in the world oil market, and provide context for the oil sands debate across political, environmental, and technological dimensions.
- **Illuminate.** A number of critical, but controversial, issues will shape the future of the oil sands. Many of these issues defy simple, clear-cut explanations. We assess these issues by identifying what is known as well as areas of uncertainty.
- **Illustrate.** We present three scenarios that describe how the future of oil sands investment and attendant issues could evolve from 2009 to 2035. The scenarios are not an attempt to identify a singular path forward. The goal is to illustrate a range of implications based on different assumptions about how the future could unfold.

*Report Process*

This report draws on input received from a series of workshops in Calgary and Fort McMurray, Alberta; and Washington, DC, in 2008 and 2009. Representatives of government, oil companies, local communities, and NGOs attended the workshops. CERA conducted our own extensive research and analysis and made site visits to oil sands production facilities. CERA has full editorial control over this study and is solely responsible for the report's contents.

*Report Structure*

This report has six chapters, including the Executive Summary.

- **Executive Summary.** This is a brief summary of the report, including CERA's Key Insights.
- **Chapter I: The Oil Sands Story.** We explain the history of the oil sands, how they are produced, their role in the oil market, and how and why matters surrounding their future development affect critical issues facing the world today, particularly energy security, climate change policy, environmental protection, and international trade and cooperation.
- **Chapter II: The Political and Social Context of Oil Sands Development.** This chapter describes the political and social issues that have an impact on oil sands development, including the US-Canada relationship, provincial regulation of development, and First Nations rights.
- **Chapter III: Critical Issues for Oil Sands Development.** This chapter identifies and assesses critical areas of uncertainty or disagreement related to oil sands development. These issues include carbon emissions, water and land use, and the pace of technological advancement.

**Report Objectives (continued)**

- **Chapter IV: Scenarios to 2035.** The purpose and value of the scenario process is explained, and CERA's three oil sands scenarios to 2035 are presented. Each scenario is based on a unique set of assumptions regarding key factors that will shape oil sands development and stakeholder interests. There is no "right" scenario, but taken together the scenarios provide a framework for exploring the implications of various development paths.
- **Chapter V: Conclusion.** Given the range of stakeholder interests, there is not a singular path forward in the discussion about oil sands development. But a shared understanding of the issues, potential benefits, and challenges will help to move the debate forward in a constructive manner. This is the unifying goal of *Growth in the Canadian Oil Sands: Finding the New Balance.*

# EXECUTIVE SUMMARY

## EXECUTIVE SUMMARY

The world is searching for the right balance between increasing oil supply to meet aspirations for higher living standards and greater energy security, while at the same time protecting the environment, particularly in the face of concern about climate change. How this mix of interests evolves will be a defining feature of the early twenty-first century.

Development of the Canadian oil sands encapsulates the complexities the world faces on energy, environmental, and security issues. The oil sands are an immense resource—second only to Saudi Arabia in recoverable oil reserves. They are the sixth largest source of new supply additions in the world since 2000—ahead of Iran, Kuwait, and China. Further development offers Canada the potential to become one of the largest oil producers in the world and to continue to expand its position as the number one foreign supplier of oil to the United States. Furthermore, the oil sands are part of the dense network of economic, political, and energy relations between the United States and Canada. The oil sands themselves are a key element in the vital trade link between the countries: Canada is the largest trading partner of the United States. The two-way trade between the countries reached $597 billion in 2008, and Canada ranks by far as the largest market for American exports of goods and services.

The future of oil sands development is of great importance to Canada's overall economy. Major US interests are at stake, and there will be a significant global impact as well. The world's demand for energy will rise over the next several decades. CERA projects that total world energy demand in 2035 could as much as double from where it is today. Alternative forms of energy, such as biofuels, wind, and solar power, will play a growing role in satisfying higher demand, but so will fossil fuels, including oil. Indeed, all forms of energy—as well as greater efficiency—will be needed to deliver and support higher living standards around the world.

Will there be sufficient future investment in innovation, energy production, and efficiency to meet the energy needs of consumers around the world? If one or more of these factors falls short, energy could constrain economic growth instead of serving as an engine of development and rising living standards. There are no easy answers to the world's energy, environment, and security challenges.

Oil today accounts for 35 percent of global energy supply—the largest share of any form of energy. In 2035 oil will still play a central role in world energy supply. CERA's estimates of global oil demand in 2035 range from 97 million barrels per day (mbd) to 113 mbd. In 2008 world oil demand was 85.2 mbd.* Even in a world of relatively slow demand growth, new supplies of oil will be needed, especially to meet demand for greater mobility among those entering middle income levels around the world and to offset declining production in existing oil fields. The size and location of the oil sands resource means it has the potential to play an increasingly important role in satisfying oil demand—especially in North America.

*The 2008 figures include 1.2 mbd of global biofuels demand.

From the economic and energy security points of view there are compelling arguments in favor of strong expansion of the oil sands. Yet, at the same time, as with any form of energy, development has an impact on the environment. The production and processing of oil sands are among the more carbon-intensive when compared to other liquid fuels. Also, the cumulative impact of development on Alberta's water and land resources and on local and Aboriginal residents is not yet fully assessed.

The recognition of the significance of oil sands provides the motivation for this CERA study. The study has three objectives:

- first, to provide local, regional, and global contexts on the oil sands and explain why issues surrounding their development matter
- second, to identify and assess issues that will affect oil sands development—with a particular focus on those that generate debate or face uncertainty
- third, using our scenario framework, to illustrate how the future could unfold under three different sets of assumptions about oil sands development, economics, politics, and technology

## THE KEY INSIGHTS

What factors will have a major impact on oil sands development? What issues are the focus of debate or face an uncertain future? A central element of this report is assessment of questions that will be critical for development but lack a shared understanding among stakeholders.

The issues surrounding future oil sands development do not necessarily lend themselves to clear-cut answers. The evolution of a number of critical issues, ranging from climate change regulation to Aboriginal rights, is uncertain. Views on the benefits and impacts of oil sands development span a wide spectrum.

CERA has identified key insights about the oil sands that illuminate issues that are uncertain or a focus of debate. These insights are informed by CERA's own research over the past eight months, combined with the results of a series of workshops in Calgary; Washington, DC; and Fort McMurray, Alberta, as well as the insights gained from the development of our three oil sands scenarios.

### Energy Security and US-Canada Relations

**The oil sands resource offers North America the possibility of further increasing continental oil supply security. Significant growth in oil sands imports into the United States will reduce the required volume of oil imports from elsewhere in the world.** The oil sands are sourced from a politically stable and secure country adjacent to the United States. The United States is a natural market for Canadian oil, since the neighboring markets are connected by pipelines. Often unrecognized is Canada's position as the number one foreign supplier of oil to the United States. Canada's share of US oil imports rose from 15 percent in 1998 to 19 percent in 2008, underscoring the deep economic and trading relationship between the two neighbors as well as the critical role of energy in that bond (see Table ES-1). In our high growth scenario the oil sands would supply 37 percent of US oil imports by 2035—far more than any other foreign supplier. Greater Canadian oil exports to the United States result in fewer imports from elsewhere in the world than would otherwise be the case—shortening supply lines, among other advantages.

**Canada and the United States have a long history of cooperation on energy issues, particularly on oil matters, although there have also been periods of significant contention. Cooperation is in the interests of both countries. A key challenge for continued cooperation is the development of a common framework for regulating greenhouse gas (GHG) emissions.** A common Canadian-US framework for regulating GHG emissions would provide a more clear and solid climate for energy investments—including oil sands—compared with a world in which conflicting regulatory schemes emerge. An integrated approach would help to reduce market distortions and trade conflicts. The challenge of developing a shared set of policies should not be taken lightly, however. Developing a truly integrated approach between the United States and Canada for regulating GHG emissions would be a major milestone in international cooperation to combat climate change.

## Greenhouse Gas Emissions

**Comparisons of the GHG emissions of oil sands to other sources of crude oil are a source of great confusion. The confusion stems from using different boundaries to measure GHG emissions.** The most comprehensive measurement of GHG emissions is on

**Table ES-1**

**Top Five Sources of Crude Oil and Petroleum Product Imports to the United States, 1998 and 2008**

(million barrels per day and share of total US imports)

**1998**

| | | Volume (mbd) | Share of Total US Imports (percent) |
|---|---|---|---|
| 1 | Venezuela | 1.72 | 16 |
| 2 | Canada | 1.60 | 15 |
| 3 | Saudi Arabia | 1.49 | 14 |
| 4 | Mexico | 1.35 | 13 |
| 5 | Nigeria | 0.70 | 6 |

**2008**

| | | Volume (mbd) | Share of Total US Imports (percent) |
|---|---|---|---|
| 1 | Canada | 2.46 | 19 |
| 2 | Saudi Arabia | 1.53 | 12 |
| 3 | Mexico | 1.30 | 10 |
| 4 | Venezuela | 1.19 | 9 |
| 5 | Nigeria | 0.99 | 8 |

Sources: US Energy Information Administration, Cambridge Energy Research Associates.

a life-cycle, *well-to-wheels* basis. The *well-to-wheels* basis includes GHG emissions from oil extraction, processing, distribution, through to the combustion of the refined products, such as gasoline and the resulting emissions that exit through the tailpipe. On this basis total GHG emissions from oil sands are approximately 5 to 15 percent higher than the average crude oil consumed in the United States. That is, about 5 to 15 percent more carbon dioxide ($CO_2$) in total is released into the atmosphere as a result of using oil sands instead of an "average" crude oil. Measuring GHG emissions in only part of the life cycle—the extraction, processing, and distribution part, or what is called *well-to–retail pump* or *well-to-pump*—can yield larger differences between oil sands and the average crude oil processed in the United States.

**GHG emissions released during the combustion of refined products, such as gasoline, account for 70 to 80 percent of total life-cycle, well-to-wheels emissions. The well-to-retail pump portion of GHG emissions accounts for 20 to 30 percent of total life-cycle GHG emissions.** GHG emissions from combustion of gasoline in an automobile will be the same regardless of the crude oil from which the gasoline is derived. Variability in GHG emissions from different sources of crude oil occurs mainly in the well-to–retail pump portion of the value chain.

**Life-cycle GHG emissions from oil sands can be higher, lower, or on par with conventional crude oils since both oil sands and conventional crude have a wide range of emissions. This is why the very notion of comparing oil sands to an "average" barrel of crude oil is an additional source of confusion in considering GHG emissions.** The United States consumes crude oils with a wide range of GHG emissions, some with emissions higher than those from the oil sands. The picture becomes even more complex since the carbon footprint of crude oil consumed in the United States is likely to change over time. First, over the life of a conventional oil field, the energy consumed to extract a barrel of oil can increase significantly because of the need for more energy-intensive extraction techniques. Second, the "average" conventional barrel imported into the United States may become heavier over time as high-quality light crude oil becomes scarcer. These issues highlight the critical importance of obtaining accurate and verifiable GHG life-cycle data from all sources of crude.

**In the near to medium term reducing GHG emissions from oil sands production through efficiency improvements is likely to prove more cost effective and technologically feasible than carbon capture and storage (CCS) technology.** In oil sands mining operations, improved process reliability can lower energy consumption per unit of oil sands processed, thereby reducing life-cycle GHG emissions. For in-situ operations, reducing the amount of steam required to produce each barrel of oil sands reaps rewards in decreased energy use and decreased life-cycle GHG emissions. This objective is consistent with advances in technology and efficiency achieved in recent years. The average amount of steam used today per unit of output is half what it was in 2000. The technology is expected to continue improving. In contrast, CCS is a longer-term option because widespread commercialization of CCS is expected to be years away, and CCS would substantially increase capital and operating costs. An additional challenge in implementing CCS for oil sands is the need to develop $CO_2$ pipelines to an appropriate storage area.

## Local Environmental Issues

**Water availability is unlikely to constrain oil sands development, but improvements in water management are necessary.** Oil sands mining operations rely on the Athabasca River for water. The water issues rise and fall with the river itself, for the river is seasonal, with much lower flow in winter than in summer. Thus, water issues are more significant in the winter. For all scenarios, water storage will be needed to meet the needs of oil sands mines during the winter months, when withdrawal limits from the river are lower. Technological improvements in the management of mining waste will also allow more water recycling and reduce the amount of water needed from the Athabasca River.

**Regulations that govern water use, waste management, and site reclamation in the Alberta oil sands will need to address the cumulative impact of the industry's growth, not just individual projects.** At the project level, government regulation of oil sands activities is stronger than in many other oil-producing regions in the world. However, given the potential scale of future activity, the cumulative impact of development could become increasingly significant. Regulatory bodies are now working to manage and provide regional standards for air quality, land impact, and water quality and consumption, in addition to the existing project-level regulations. Such cumulative regulations will be important for public acceptance of further oil sands development, as land impacts and water consumption are some of the most visible environmental aspects of these projects.

**Research and technology improvement are needed to treat oil sands mining waste and reclaim tailings ponds.** The tailings ponds store water and waste material (the tailings) from the oil sands extraction process. They currently cover an area equal to Staten Island, New York. Water from the ponds is recycled back into the process. The ponds also contain a layer of *fluid fine tailings*, a mixture of water and fine clay and silt that is the consistency of pudding or yogurt. Water does not separate naturally from this material. Removing enough water to turn fluid fine tailings into a firm surface that can support equipment traffic is one pathway for land reclamation. Technology for removing water from fluid fine tailings is advancing, and trials of several technologies are under way. End-pit lakes (EPLs) are a second method for incorporating fluid fine tailings into the landscape during land reclamation. EPLs consist of mining waste capped with a layer of fresh water. These lakes are designed to become permanent features in the landscape. No EPLs have yet been constructed, and research is needed to determine whether these lakes can become active ecosystems that support plant and animal life.

## Impact on Aboriginal and Local Communities

**The exercise of First Nations community rights could affect the pace and scope of oil sands development.*** People of First Nations heritage make up approximately 2.8 percent of Alberta's 3.6 million population, totaling approximately 100,000 people. By law, First Nations groups must be consulted by government and industry on all development within the oil sands area that affects their traditional way of life, but the nature and process of this

*First Nations groups are indigenous Canadians that live south of the territory occupied by the Inuit people, a culturally and linguistically separate group of indigenous Canadians. Métis are people of mixed indigenous and European heritage. These three groups together constitute Canada's Aboriginal population.

consultation is under debate. Lawsuits by some First Nations groups currently in the courts challenge the way they are consulted prior to oil sands projects. In addition some First Nations groups downstream from oil sands developments have particular concerns about the health effects that some assert may be caused by the leakage of industry waste. However, the oil sands also represent a growing economic opportunity for Aboriginal communities, with long-term job opportunities and potential equity partnership in some projects.

**Infrastructure constraints and cost inflation of goods, services, and labor will affect the pace and cost of oil sands investment.** The rapid growth over the past several years has increased strains on housing, infrastructure, and community services in the oil sands region and resulted in a high cost of living. If these pressures are not alleviated, the region will have difficulty attracting people needed for essential services. All of this ultimately could slow long-term growth in the oil sands industry. The sudden slowing of industry investment in the wake of the recent oil price slump could give the region a chance to catch up with the population growth that occurred over the past several years. The region's dependence on the cycles of one industry complicates planning and underscores the need for industry and government innovation to address these "boom and bust" issues.

## Economics

**Oil sands, like other complex oil projects around the world such as deepwater developments, face the challenge of high costs.** The oil price collapse from $147 to the $40 to $60 range rendered many planned oil sands projects uneconomic. At the peak of oil industry capital cost inflation, in summer 2008, the threshold crude oil price for an oil sands project ranged from about $60 to $85 per barrel.* Since the oil price decline, more than 70 percent of proposed projects have been postponed. Although oil sands costs are roughly comparable to some other potential large new sources of supply, they are more expensive than many projects in the Middle East and other lower-cost producing regions. Oil industry costs have begun to ease, but unless major technological breakthroughs result in lower costs, the oil sands will remain among the higher cost oil supply options.

## Natural Gas Demand

**The oil sands are a major consumer of natural gas, today representing about 20 percent of Canadian demand. That could grow to 25 to 40 percent of Canadian demand by 2035.** Even considering sizable new unconventional supply, Canadian domestic gas production is currently expected to peak around the middle of the next decade. Without the addition of new supply, such as from the Mackenzie Delta and Alaska, exports from Canada to the United States might decline in order to meet the needs of a rapidly expanding oil sands sector. However, improved efficiency can reduce oil sands demand for natural gas. Additionally, gasification of petroleum coke or asphaltenes, small nuclear facilities, and use of solvents are all technologies under development that could reduce natural gas demand, although they have yet to be demonstrated commercially in the oil sands.

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*The crude oil prices are for West Texas Intermediate and assume a 10 percent rate of return. CERA's cost estimates are based on actual costs at the time and not future cost expectations. These cost estimates are based on a 20 percent per barrel light-heavy crude price differential, capital cost of $126,000 per flowing barrel for an integrated mine and upgrader, $30,000 per flowing barrel for steam-assisted gravity drainage (SAGD), and exchange rate parity.

## The Innovation Challenge

**The pace of technological innovation in the oil sands has been substantial, and further advances should be expected. However, cooperation between governments and the private sector is crucial for the advancement of certain technologies, which requires stepped-up government support of research and development (R&D).** Since the inception of the first commercial oil sands facility in 1967, the industry has made major technological strides in optimizing resources, innovating new processes, reducing costs, increasing efficiency, and reducing its environmental impact. Advances in mining technology and the development of the SAGD technique for in-situ production have reduced costs and GHG emissions. Incremental improvements will continue; several new technologies in various stages of development have the potential to radically change oil sands production. All of these, however, must be proven effective and economically viable on a commercial scale. Many potential advances will require the kind of basic research and demonstration that individual companies do not have the resources or incentive to conduct. Government-private partnerships will be important in the advancement of technologies to address environmental and efficiency challenges. The environmental and efficiency challenges for oil sands are classic cases for consistent, long-term government R&D spending. The importance of oil sands establishes why stronger multiyear government support for R&D across a broad range of technologies, not just CCS, is vital.

## CERA'S THREE OIL SANDS SCENARIOS

The complexity and uncertainty of the oil sands' future lends itself to application of CERA's scenario process. No one can accurately predict the future, but we can explore the key forces that will shape the future and assess the impact of different outcomes. Scenarios acknowledge uncertainty and illustrate how the future could evolve in different ways. They encourage people to think about the future in a flexible way by disengaging from their current point of view and interests—and the inevitable human tendency to simply extrapolate from what is happening today.

*Growth in the Canadian Oil Sands: Finding the New Balance* builds scenarios around issues specific to the Alberta oil sands. CERA's scenarios represent three different potential outcomes intended to explore the boundaries for oil sands development. They are by no means the only possible paths of development that could be envisioned. Indeed, it is possible that the future will ultimately contain elements of all three scenarios. CERA does not assign probability to any scenario, but encourages stakeholders, policymakers, and industry to use the scenarios to think as broadly as possible to understand the forces of change and how to adapt to them.

CERA's three oil sands scenarios are briefly summarized below. The full scenarios are in Chapter IV of this report.

### *New Social Order*

*New Social Order* imagines a world in which governments attempt to remake their economies on a platform of clean energy. The global economic crisis that began in 2008 is followed by severe oil supply disruptions, leading to a multiyear spike in oil prices above $100 per barrel. An activist government role in the Canadian and US economies along with strong policies to limit GHG emissions encourages expansion of alternative forms of energy. Regulatory oversight of the oil sands tightens further, particularly to address the cumulative impacts on air and water quality and land use created by oil sands development.

Oil sands production capacity initially grows rapidly in response to the rush of investment that follows the extended oil price spike. However, by 2020 industry costs have risen sharply, petroleum demand in North America is in permanent decline, and oil prices are in retreat. Environmental regulations are also significantly tighter. The intersection of increasing costs and declining oil prices squeezes producers' margins and deters significant oil sands developments after 2020. Having reached 2.9 mbd by 2020—which represents more than a doubling from current levels—oil sands capacity essentially stagnates for the rest of the scenario period. In 2035 production is 3 mbd.

A key feature of the New Social Order scenario is the rapid development of technology. Technology not only enables the scale-up of alternatives to petroleum, such as next generation biofuels and electric vehicles, it also allows the oil sands industry to reduce its environmental footprint. As a result of improved efficiency and advanced technologies, the GHG intensity of oil sands production improves by over 30 percent between 2008 and 2035.

### *Barreling Ahead*

The *Barreling Ahead* scenario illustrates conditions that allow Canada to become one of the biggest producers of petroleum in the world by 2035. The scenario explores the economic and energy security benefits, as well as the environmental impacts of such an expansion.

In this scenario the Canadian government plays a strong role in maximizing the development of Canada's vast energy resources, ranging from support for new infrastructure to stepped-up R&D funding (including establishment of the Research and Innovation Network). A "great recovery" follows the "great recession" of 2008 and 2009, leading to sustained strong oil demand growth and robust light, sweet crude oil prices. Strong oil prices and moderation of industry costs support continuous investment in both integrated and upstream-only oil sands projects. Ultimately oil sands production reaches 6.3 mbd in 2035. At this level of production Canada is by far the biggest source of oil for the US market, supplying 37 percent of US oil imports. Asia, with its rapid rise in oil consumption, becomes an important new market for oil sands products outside of North America.

Growing demand for natural gas and water, management of mining waste, and land reclamation are all challenges posed by the rapid rate of production growth in Barreling Ahead. Natural gas consumption by oil sands projects reaches 40 percent of total Canadian gas demand by 2035. Oil sands–related GHG emissions also rise sharply, ultimately representing about 20 percent of total Canadian GHG emissions.

### *Deep Freeze*

In the *Deep Freeze* scenario the great recession of 2008 and 2009 is just the prelude to a "great stagnation," in which low rates of economic growth persist for years in both North America and the overall global economy. Globalization—the prevailing economic paradigm of the past several decades—loses ground to the forces of nationalism, insularity, and protectionism.

Oil demand growth is sluggish and oil prices are weak for most of the scenario. Without question the economic and oil price environment of Deep Freeze is the most challenging of the three scenarios for Canadian oil sands producers. The oil sands boom is followed by a great—and long—bust. Only new projects well into their construction phase proceed, leading to some continued growth in the early part of the scenario's first decade. By 2013 production has reached 1.8 mbd, 0.5 mbd higher than current levels, but the development process for new oil sands projects comes to a virtual halt.

Some moderate production growth occurs through the second decade of the scenario period, as oil demand growth gradually recovers, capital costs in the oil sands drop, and the pace of new environmental regulation slows. Owing to relatively favorable economics for incumbent oil sands producers, total industry capacity grows very gradually, through expansion of existing facilities. Ultimately oil sands capacity reaches 2.3 mbd by 2035, the weakest of the three scenarios.

## CONCLUSION

The oil sands today have moved from the fringe of energy supply to the center. Their commercial development makes Canada the world's second largest holder of recoverable oil reserves and an increasingly important part of the fabric of hemispheric and global energy security.

But new challenges face the oil sands industry. The world's most severe economic downturn in decades has cast a chill on many investment plans. Also, like other energy sources, the oil sands will be affected by the future path of GHG regulation in Canada and the United States. Increasing effort will go into technological advances that help manage emissions in the production of oil sands. Locally, a growing focus on the cumulative environmental impacts could change future water and land use.

Recognizing the significance and impact of oil sands is very important, and approaching the questions about oil sands in a sound fashion is essential. To do otherwise is to risk wider disruption in US-Canadian relations and other negative consequences. This report combines

IHS CERA's research with the learning and insights from workshops involving a wide range of organizations and stakeholders. The objective is to contribute to finding that appropriate balance on oil sands development that meets economic and security needs and, at the same time, safeguards the environment.

# CHAPTER I: THE OIL SANDS STORY

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## GROWTH IN THE CANADIAN OIL SANDS: FINDING THE NEW BALANCE

> Since the deposits of tar sand in Alberta are practically inexhaustible, much is hoped in Western Canada from their exploitation.
>
> —*New York Times,* April 7, 1935

For more than a century the oil sands of Alberta, Canada, have fostered great expectations. When the geologist Robert Bell speculated in 1884 that the oil sands were part of an enormous oil reservoir, it sparked an enduring vision of prosperity and greater North American energy security. This fired the imagination of entrepreneurs such as "Bitumen Bill"—a failed fur trader turned oil sands enthusiast. His quest for oil was frustrated by technical challenges, but he successfully trumpeted the possibilities in government halls.* The potential of the oil sands motivated both the Alberta provincial and Canadian federal governments to find ways to separate the oil from the sand. A chemist, Dr. Karl Clark, cracked the code in 1920. But the large-scale exploitation of Canadian oil sands was still a long way off.

The technical and economic barriers separating early pioneering efforts from large-scale commercialization were formidable and stubborn. It was not until 1967 that Great Canadian Oil Sands Ltd. established the modern age of commercial oil sands production. Even then it took until 2000—and required many advances in engineering—for the oil sands industry to reach a production level of 600,000 barrels per day (bd), equivalent to the output of a medium-size oil company. But then over the next eight years production growth picked up rapidly and more than doubled. The rise in oil prices from 2002 to 2008, a stable operating environment, attractive fiscal terms, and the open investment climate in Canada—numerous foreign and domestic companies are active—spurred the rise in oil sands output. By 2009 oil sands production reached 1.3 million barrels per day (mbd), near the total amount of oil produced by Kazakhstan or Algeria. Putting this growth in comparative terms, if measured as an individual country, the Canadian oil sands would be number six in the world in supply expansion since 2000, ahead of Kuwait, China, and Iran (see Table I-1).

Although the pace of oil sands expansion has been rapid in recent years, the future rate of growth is uncertain because of the current severe global recession and ongoing concerns about the environmental impact of oil sands development. But clearly the eventual outcome will be a decisive factor in the balance between global energy demand and supply and for energy security.

### Oil Sands in the Global Energy Context

The immensity of the oil sands is their signature feature. It was the source of inspiration for Bitumen Bill and the main driver behind more recent government and oil company efforts to increase investment and output. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 173 billion barrels.** This is more than

**The New York Times,* May 28, 1922.
**This figure does not include the potential for reserves in Alberta's eastern neighbor, Saskatchewan. The source of this data is IHS.

**Table I-1**

**Top 15 Sources of World Oil Supply Growth, 2000–08**
(million barrels per day)

| | | 2000 | 2008 | Volume change 2000 to 2008 |
|---|---|---|---|---|
| 1 | Russia | 6.52 | 9.79 | 3.27 |
| 2 | Saudi Arabia | 9.07 | 10.45 | 1.38 |
| 3 | Angola | 0.75 | 1.89 | 1.15 |
| 4 | Brazil | 1.45 | 2.27 | 0.82 |
| 5 | Algeria | 1.44 | 2.21 | 0.77 |
| **6** | **Canadian oil sands** | **0.60** | **1.30** | **0.70** |
| 7 | Kazakhstan | 0.72 | 1.41 | 0.69 |
| 8 | Azerbaijan | 0.29 | 0.90 | 0.61 |
| 9 | Kuwait | 1.88 | 2.48 | 0.60 |
| 10 | United Arab Emirates | 2.62 | 3.21 | 0.59 |
| 11 | China | 3.23 | 3.81 | 0.58 |
| 12 | Qatar | 0.86 | 1.41 | 0.55 |
| 13 | Iran | 3.76 | 4.29 | 0.53 |
| 14 | Libya | 1.47 | 1.87 | 0.40 |
| 15 | Sudan | 0.18 | 0.49 | 0.31 |

Sources: Cambridge Energy Research Associates, International Energy Agency.
Note: Total Canadian oil production was 2.72 mbd in 2000 and 3.41 in 2008.
The total net increase in Canadian production was 0.69 mbd.

ten times greater than US oil reserves and well above the 115 billion barrels that is currently estimated for Iraq. Only Saudi Arabia has a larger oil reserve base. Although the current severe global recession is slowing investment, the potential remains for the oil sands to make Canada one of the very few countries in the world that could substantially increase oil production for the next several decades.

What role will the oil sands play in the context of global energy supply and demand? The drive for higher living standards in China, India, the Middle East, Russia, and elsewhere will, in the long term, remain as strong as it was in Europe, Japan, and the United States in the post–World War II years. Higher living standards mean longer life expectancy, lower infant mortality—and higher world energy consumption. Demand for energy will rise globally over the next several decades—as it will in the United States and Canada. CERA projects that world energy demand in 2035 could be 60 to 100 percent higher than the 2008 level. Alternative forms of energy, such as biofuels, wind, and solar power, will play a role in satisfying higher demand, but so will fossil fuels, including oil. Indeed, all forms of energy—as well as greater efficiency—will be needed to deliver higher living standards around the world.

Oil today accounts for 35 percent of global energy supply—the largest of any form of energy. In 2035 oil will still play a key role in providing the world with energy. CERA's estimates of global oil demand in 2035 range from 97 to 113 mbd. In 2008 world oil demand was

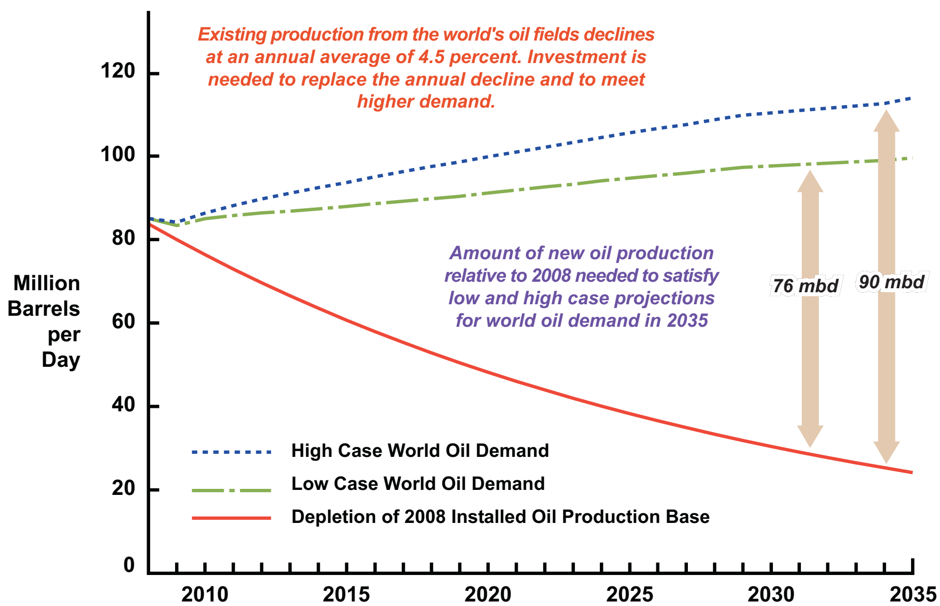
85.2 mbd.* Even in a world of relatively slow demand growth, more oil will be needed, especially to satisfy the demand for greater mobility among those entering middle income levels around the world.

The challenge to increase fuel supply is not simply about filling the gap between current and future demand. Oil is a depleting resource. Each year, the installed production base of the world's oil fields declines at an aggregate average of 4.5 percent.** This means, for example, that even if demand does not change from one year to the next, the global oil industry still needs to replace about 3.8 mbd of production to offset field depletion.*** By 2035 the world will need to find, develop, and produce 76 to 90 mbd of liquid fuel supply that was not in production in 2008 (see Figure I-1).

The size of the oil sands resource along with a production profile notable for a long and stable production plateau means that the oil sands could play an increasingly important role in satisfying the world's demand for energy. Indeed, the oil sands place Canada

**Figure I-1**

**Filling the Gap: Significant Investment Needed to Offset Oilfield Production Decline**




Source: Cambridge Energy Research Associates.
90107-31

*The 2008 figures include 1.2 mbd of global biofuels demand.
**The aggregate annual decline figure includes fields that are increasing production, fields at production plateau, and fields in decline. It is based on the 2007 CERA Private Report *Finding the Critical Numbers: What Are the Real Decline Rates for Global Oil Production?*
***The 3.8 mbd of depletion is calculated based on 2008 global oil production (excluding processing gains) of 83.9 mbd. The amount of oil that needs to be replaced will change in line with future production levels.

among the "O-15"—CERA's list of the top 15 countries in terms of potential to increase oil production over the next decade (see Figure I-2). It is one of only two countries in the Western Hemisphere on the list, the other being Brazil.

So what role could the oil sands play in satisfying higher energy demand—and the desire for higher living standards? The range of oil production capacity in the oil sands in 2035, based on CERA's scenarios, ranges from 2.3 to 6.3 mbd. At the high end this would make it one of the very largest oil-producing regions in the world. Even at the lower end it would still be a significant source of world oil supply; few countries today produce more than 2 mbd.

If oil sands development faces a long-run standstill, then other resources would have to be developed elsewhere in the world or the possibility of higher energy prices would arise. To be sure, development of energy supply exacts costs, and the oil sands are no exception.

## Big Resource, Big Challenges

A big resource often faces big challenges—and significant costs. Oil sands are not cheap to develop and produce. Indeed, high costs were the reason that it took the better part of a century for commercial production to commence. At the peak of the recent oil boom in

**Figure I-2**

**The O-15: The 15 Countries with the Most Potential to Increase Oil Production to 2020**


Source: Cambridge Energy Research Associates.
90107-32

2008, the oil price needed to justify investment ranged from around $60 per barrel to $85 per barrel.* At the higher end of the range it placed the oil sands well above the cost of most other sources of oil supply. There are also environmental costs. With current technology the amount of carbon dioxide ($CO_2$) emitted during the production process places oil sands among the more carbon-intensive forms of liquid fuels. Water consumption and management as well as land use and reclamation are also of concern. We explore these issues in more detail in Chapters II and III.

Other significant challenges include managing the effects of development on the lives of Aboriginal people and on the natural landscape. The roles and responsibilities of government and oil sands investors regarding concerns of Aboriginal people lack clarity. This is an impediment to conflict resolution. Coping with dynamic infrastructure requirements linked to the booms and busts of the oil industry is a perennial challenge for local government. In the Municipality of Wood Buffalo—the de facto capital of the oil sands region—population growth has put great pressure on infrastructure and local services.

Debate is wide-ranging about the appropriate pace of development and environmental protection, but one aspect of the oil sands industry is clear: it has become an important engine of economic activity for Alberta and Canada. The United States also benefits from spending to develop oil sands. Specific economic benefits include

- More than C$150 billion was spent from 2000 to 2008 on oil sands development and related activities. About 80 percent of this was spent in Canada and 20 percent in the United States and other countries.
- Approximately 240,000 jobs are directly or indirectly related to the oil sands.
- More than C$30 billion in government revenues were collected from oil sands–related activities from 2000 to 2008. Revenues were paid to municipal, provincial, and federal governments.**

## Oil Sands Development: A North American Issue

Few bilateral relationships match the history and density of links between Canada and the United States. The two countries enjoy a long history of cooperation based on deep economic and cultural connections. A very visible manifestation is the longest unmilitarized border in the world, across which roughly $1.5 billion worth of goods is traded every day. Canada is the largest trading partner of the United States. On security matters, in addition to both being members of the North Atlantic Treaty Organization, Canada and the United States have jointly run since 1958 the North American Aerospace Defense Command.

*The crude oil prices refer to West Texas Intermediate and assume a 10 percent rate of return. CERA's cost estimates are based on actual costs at the time and not future cost expectations. These cost estimates are based on a 20 percent per barrel light-heavy crude price differential, capital cost of $126,000 per flowing barrel for an integrated mine and upgrader, $30,000 per flowing barrel for steam-assisted gravity drainage (SAGD), and exchange rate parity. Projects announced in summer 2008 had higher capital costs than our estimates of actual costs at that time. Announced projects included expectations of future cost increases.
**CERA estimated the economic benefits based on the methodology outlined in the Canadian Energy Research Institute's 2005 report on the economic impacts of the Alberta oil sands industry.

Energy has long been a key pillar of the bilateral relationship, and the oil sands are an increasingly important part. Canada is, by far, the largest oil exporter to the American market. In 2008 Canada accounted for 19 percent of US oil imports, and an increasing proportion of this share consists of oil sands–derived liquids.* The number two supplier of oil to the United States, Saudi Arabia, accounted for 12 percent of imports. If the oil sands were a country, they would be the sixth largest exporter of crude oil to the United States, ahead of Algeria, Angola, and Iraq. Unlike other foreign sources of oil, Canadian oil is linked to the United States by pipeline and is not dependent on waterborne crude oil carriers. Canada is also the number one source of natural gas imports to the United States, accounting for 90 percent of total imports and 15 percent of total supply in 2008.

Oil is often an important part of the dialogue between the countries and their leaders. This is certainly the case today. On the eve of his trip to Canada, and maiden voyage abroad as president of the United States, President Barack Obama framed the oil sands challenge this way, "The dilemma that Canada faces, the United States faces, and China and the entire world faces is, how do we obtain the energy that we need to grow our economies in a way that is not rapidly accelerating climate change?"

The questions raised about future oil sands development are related to the many critical issues facing North America today. Will Canada and the United States develop a common framework on regulation of greenhouse gas (GHG) emissions—a factor that could have a large impact on investment? What is an appropriate balance between oil supply security and environmental protection, and how can these objectives be met at the same time? The outcome of these issues will reverberate in both Canada and the United States for years to come.

## The Need for Common Understanding and Framework

The onset of a severe global recession in late 2008, which pushed oil prices down from a peak of $147 per barrel to around $40 to $50 in just a few short months, cast a chill on oil sands investment—as it did on other segments of the energy industry. Many projects have been postponed. Growth projections have been revised down. The size of the oil sands workforce has plummeted. By the end of 2010 the construction workforce is projected to be less than 30 percent of that of summer 2008 and well below the Alberta labor supply.

The timing of a global economic recovery is an immediate concern that will certainly affect the pace of investment and economic development. But other issues loom large and will endure after the worst of the "great recession" is behind us. These issues are in the realm of environmental regulation, technology, oil market trends, industry costs, and US-Canada relations. Many of these issues do not lend themselves to clear-cut sound bites or headlines. The complexity and dynamic nature of the factors that shape the oil sands industry make easy answers elusive. Future development and investment paths can produce benefits in one domain but costs in another. For example, a cost for emitting $CO_2$ would help to constrain such emissions and combat climate change but could also negatively affect energy security.

*US Energy Information Administration data for crude oil and product imports.

Identifying what is known and not known on key issues, particularly where there is great controversy, is critical to developing a shared frame of reference to advance dialogue among stakeholders in the oil sands industry. This CERA study aims to provide an objective, fact-based assessment of the issues that will shape the oil sands industry—particularly on matters where there is a wide range of perspectives—and provide local, regional, and global context for how the oil sands fit into the global energy picture. This assessment then provides the context for examining how the future could unfold using different assumptions in three scenarios to 2035. It is not our intention to identify the "right" way forward. Instead, the aim of this CERA study is to contribute to broader understanding of the risks, benefits, and impacts of oil sands development and to finding an appropriate balance between oil sands development and related economic, environmental, and social concerns.

### The Oil Sands: What, Where, and How?

Grains of sand covered with water, bitumen, and clay—these are the oil sands. The "oil" in the oil sands comes from bitumen, an extra-heavy oil with high viscosity. Bitumen does not flow like a liquid at room temperature. Instead, raw bitumen is akin to an ice hockey puck. 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.

The bitumen content of the oil sands ranges from about 1 to 18 percent. The rest is mainly sand—principally quartz—and water. There are traces of other substances such as iron, mica, nickel, titanium, vanadium, and others. Oil sands producers separate the bitumen from the sand and water in order to derive the feedstock from which marketable oil is manufactured.

*Where Are the Oil Sands?*

Canada's oil sands are concentrated in three major deposits. The largest is the Athabasca, a large region around Fort McMurray in northeastern Alberta. The other two areas are Peace River in northwest Alberta and Cold Lake, east of Edmonton (see Figure I-3). There are also oil sands deposits in Saskatchewan, but their commercial viability has yet to be established. Outside of Canada, bitumen or extra-heavy oil deposits are found in many places around the world, but the only other large-scale development is in Venezuela.

*How Are the Oil Sands Produced?*

Conventional oil is a liquid that flows naturally or is induced to flow through enhanced recovery techniques from underground formations. Oil sands are unique in that they are produced via both surface mining and in-situ thermal processes.

- **Mining.** About 20 percent of currently recoverable oil sands reserves lies close enough to the surface that it can be mined. In a strip-mining process similar to coal mining, the overburden, primarily soils and vegetation, is removed, and the layer of oil sands is excavated using massive shovels that scoop the sand on to 400-ton trucks that transport it to a processing facility (see Figure I-4). The first two large-scale oil sands plants, which commenced in 1967 and 1978, are such mining operations. In 2008 over 55 percent of oil sands output was mined. The minable portion of the oil sands is located north of Fort McMurray and is orange-shaded on Figure I-3. The current footprint of mining operations is about 200 square miles (518 square kilometers), or about 2 percent of the total area of the greater Houston, Texas, metropolitan area.* It generally takes about two metric tons of mined oil sands material to produce 0.13 tons (approximately one barrel) of synthetic crude oil (SCO).

**The Oil Sands: What, Where, and How? (continued)**

- **In-situ thermal processes.** About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered using in-situ thermal processes. Two thermal processes are in use today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). Both methods inject steam to lower the viscosity of the bitumen and allow it to flow to the surface. CSS is primarily used in the Cold Lake and Peace River areas, whereas SAGD predominates in the Athabasca region. Production from CSS and SAGD were roughly equivalent in 2007 at about 200,000 bd each. In 2008 SAGD production exceeded CCS. SAGD is expected to account for a large share of the total growth in oil sands output. Figure I-5 illustrates the SAGD process. The steam-oil ratio (SOR) is a critical variable for thermal production. It measures how much steam—generally made via natural gas—is needed to produce a barrel of bitumen. For example, an SOR of 3 means that three barrels of water at atmospheric pressure and temperature must be vaporized into high-pressure steam to produce one barrel of bitumen. Much of the of the water used to make steam comes from the production of the bitumen and is recycled.

*What Is the Final Product?*

Raw bitumen cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with a light oil liquid 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 light crude oil (see Figure I-6).

- **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 an API gravity typically greater than 35 degrees. However, since SCO produces a more limited range of products compared with conventional crude oil, a typical refinery can use SCO as only a small fraction of its total feedstock.**
- **Diluted bitumen (dilbit)** is bitumen mixed with a diluent. The diluent is typically a natural gas liquid such as condensate. Dilbit is generally a mix of 70 percent bitumen and 30 percent condensate. This is done to make the mixed product "lighter," and the lower viscosity enables the dilbit to be shipped in a pipeline. A typical refinery will need modifications to process large amounts of dilbit feedstock because it produces more heavy oil products than most crude oils. Dilbit is also lower quality than most crude oils. It contains high levels of salt, sulfur, nitrogen, metals, and aromatics. Dilbit also has a high amount of corrosive acid, as measured by the total acid number (TAN). The high acid limits the number of refineries that can process dilbit. Refineries already configured to process very heavy oil are the exception. For other refineries, upgraded metallurgy is often required to process dilbit. Not all bitumen has the same acid level—and oil sands from the Cold Lake region tend to have the lowest acid levels.
- **Synbit** is typically a combination of 50 percent bitumen and 50 percent SCO. The properties of each kind of synbit blend vary significantly, but the blending of the lighter SCO with the heavy bitumen results in a product that more closely resembles conventional crude oil.

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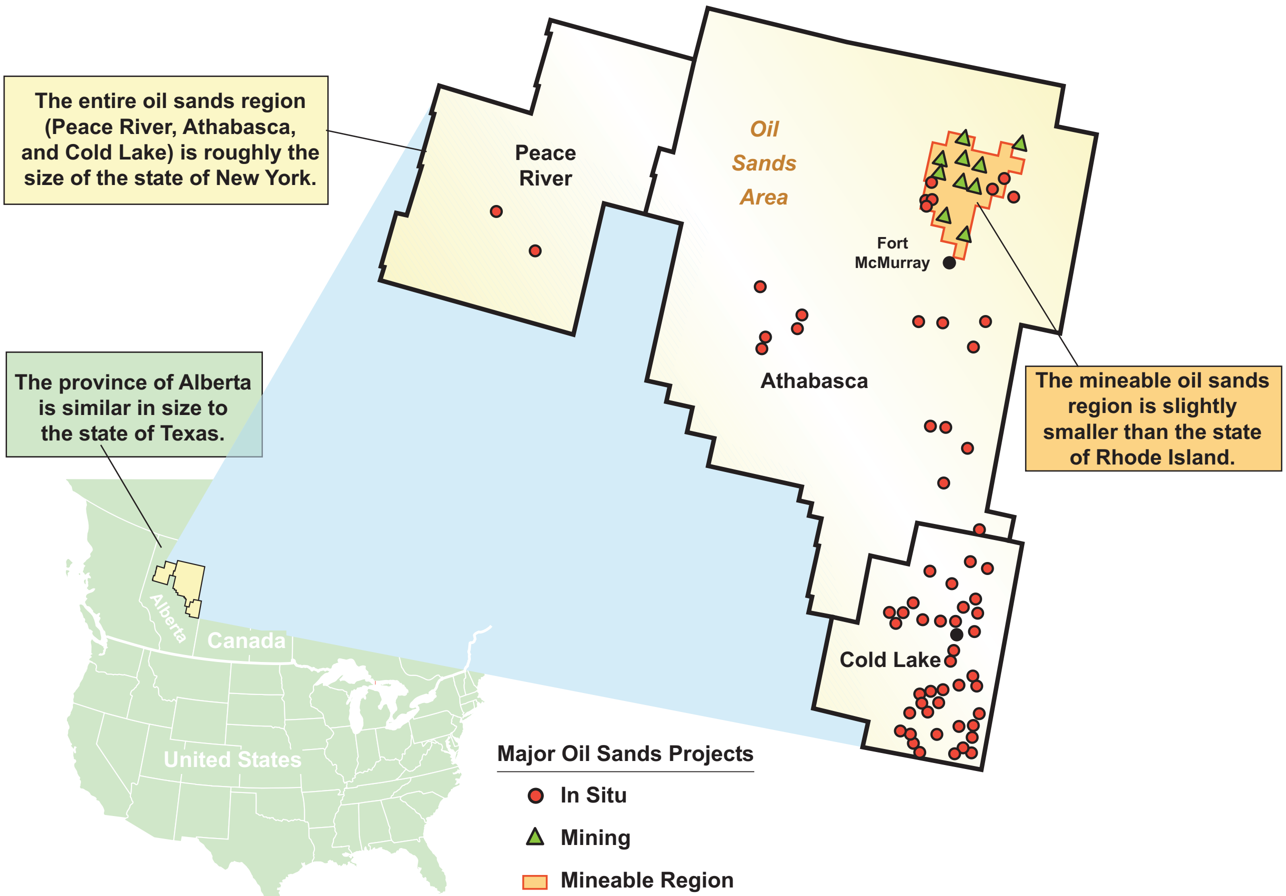
*Disturbed land is 200 square miles due to surface mining. The total amount of land leased for surface mining is 1,350 square miles, which is equivalent to 0.5 percent of Alberta's total land.
**Since SCO does not contain residual (heavy) oil, processing too much SCO will lead to imbalances in the refining process that will reduce the refinery's throughput.

**Figure I-3**

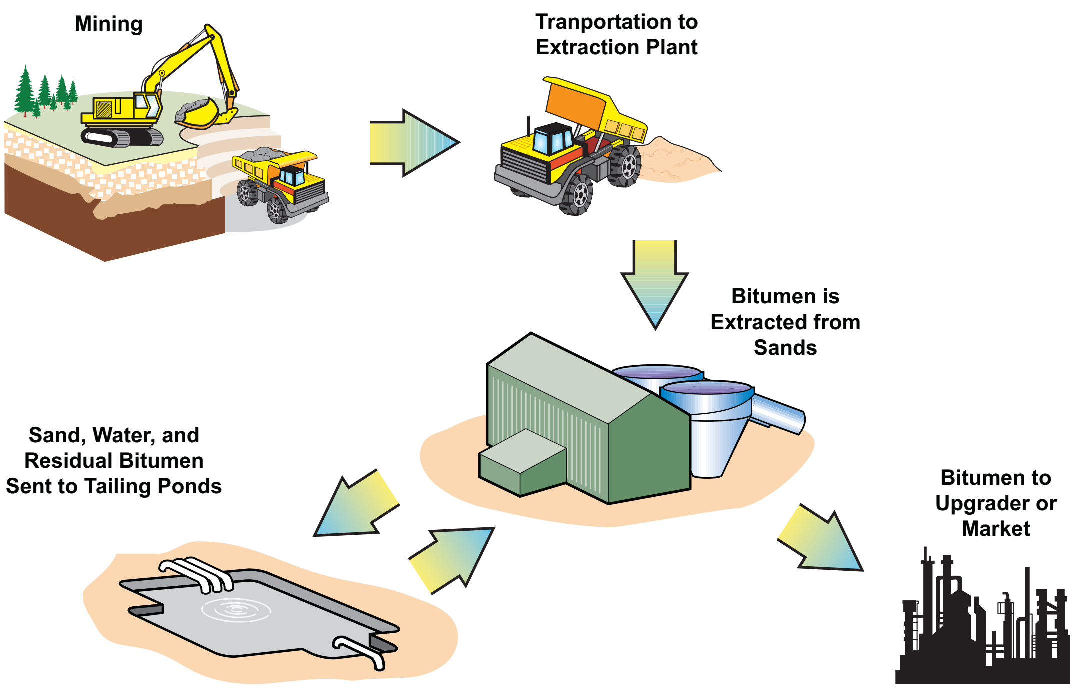
**Location of Canadian Oil Sands Resources**




Source: Cambridge Energy Research Associates,
Note: Comparisons to US states are to the total areas of the states, including land and water.
60713-19

**Figure I-4**

**Oil Sands Mining Process**




Source: Cambridge Energy Research Associates.
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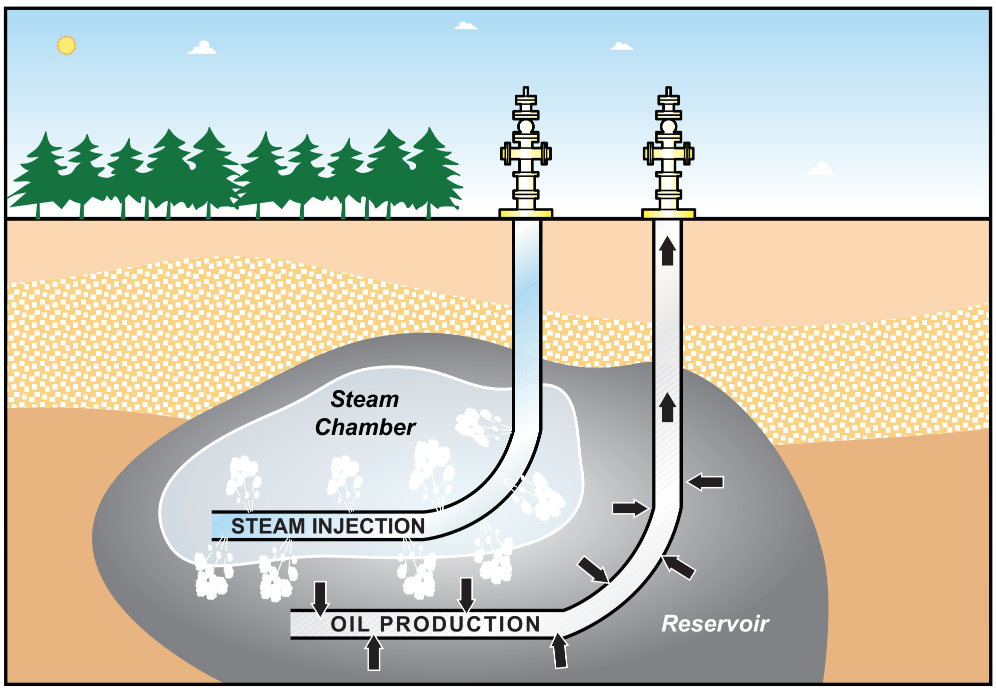
**Figure I-5**

**The Steam-assisted Gravity Drainage (SAGD) Production Technique**




Source: Cambridge Energy Research Associates.
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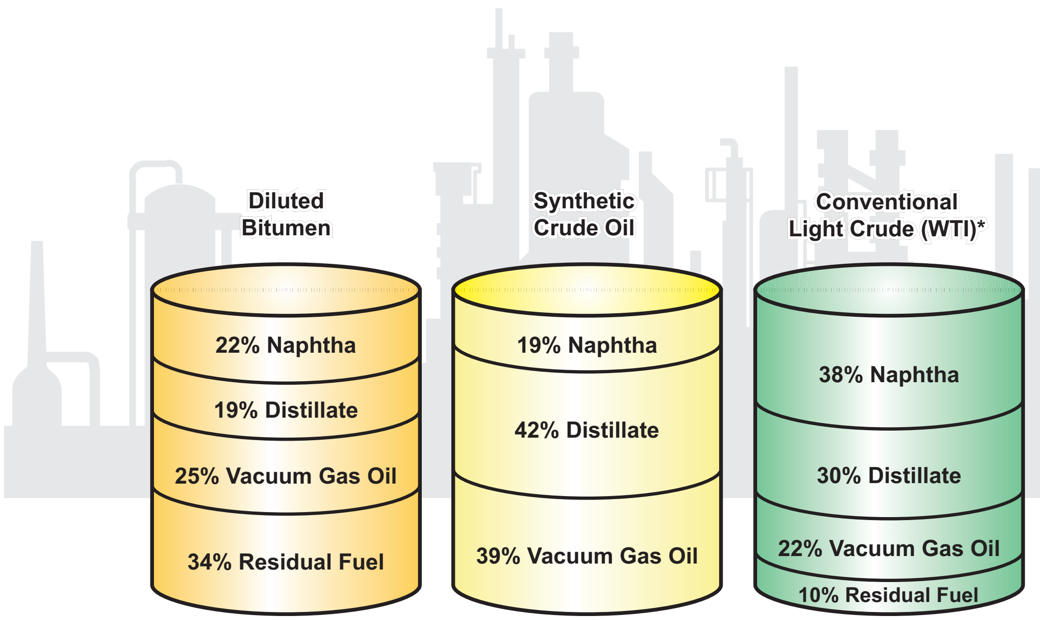
**Figure I-6**

**Products Derived from Oil Sands Compared to Conventional Light Crude**




Source: Cambridge Energy Research Associates.
Note: Percentages are approximate and can differ based on specific liquid qualities and the refinery in which it is processed. Gasoline is derived from naphtha material. Distillate material produces diesel fuel, heating oil, and jet fuel. Vacuum gas oil is a heavier material that can be upgraded to yield both gasoline and distillate. Residual fuel is a very heavy, low value material typically used as boiler fuel. It can also be upgraded to lighter products, although this requires deep conversion refinery units.
*WTI is West Texas Intermediate (WTI), which is a conventional light crude oil. WTI is the price benchmark for oil sold in the United States.
90107-11

# CHAPTER II: THE POLITICAL AND SOCIAL CONTEXT OF OIL SANDS DEVELOPMENT

# CHAPTER II: THE POLITICAL AND SOCIAL CONTEXT OF OIL SANDS DEVELOPMENT

Policy at every level of government influences oil sands development. The nature of the relationship between Canada and the United States will influence future policy to regulate greenhouse gas (GHG) emissions and affect the downstream market competitiveness of products produced from oil sands. The Canadian federal and Alberta provincial governments' stance on oil sands is also critical and changing. Alberta recently released a long-term development plan for the oil sands, focusing more on sustainability than in the past. First Nations groups have treaty rights throughout the oil sands area, and some First Nations are challenging oil sands developments. The rapid growth of the oil sands industry has challenged the infrastructure and social services in the Regional Municipality of Wood Buffalo, the center of Alberta's oil sands development.

## OIL SANDS: THE LATEST CHAPTER IN US-CANADA ENERGY RELATIONS

**Key question: Will Canada and the United States work cooperatively to develop common and complementary policies on energy issues and on GHG emissions—or will national perspectives dominate?**

**Why it matters: Past cooperation between Canada and the United States on energy issues has been mutually beneficial. In contrast, during times when common ground was not reached, trade and investment in oil was negatively affected. The degree of future US-Canada cooperation will influence policy on GHG emissions, which will shape oil sands development and downstream market access.**

### Continental or National Perspective?

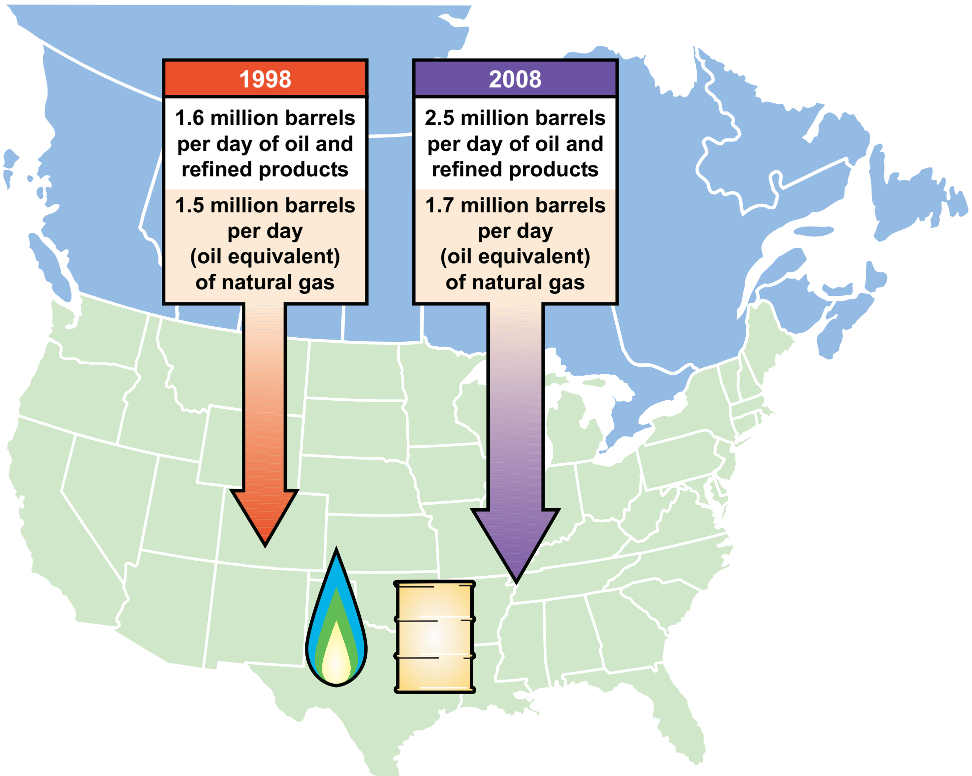
Physical connections between Canada and the United States create a strong bond—8,891 kilometers (5,521 miles) of shared border and $596.9 billion in annual trade flows.* Oil and gas provide another strong connection. The United States is virtually Canada's sole oil and gas export market at present. In 2008 Canadian oil and gas exports totaled 4.2 million barrels per day of oil equivalent (mbdoe)—more than double the number two US supplier (see Figure II-1).**

The oil and gas connection reflects a shared vision of the benefits of an integrated continental oil and gas market. But there have been times when a shared vision was elusive—and trade and investment suffered. Will the future be marked by cooperation based on a shared vision or by disengagement?

*In 2008 the United States exported $261.4 billion of goods to Canada and imported $335.5 billion.
**According to the US Department of Energy in 2008 Canadian crude oil (including oil sands) and refined product exports totaled 2.5 mbdoe and Canadian natural gas exports totaled 1.7 mbdoe. According to the National Energy Board of Canada, 0.7 mbdoe of synthetic crude and blended bitumen from the oil sands were exported to the United States in 2008.

**Figure II-1**

**Canadian Crude Oil, Refined Products, and Natural Gas Exports to the United States, 1998 and 2008**




Source: Cambridge Energy Research Associates.
90107-33

Bilateral relations between Ottawa and Washington are crucial. Trends in the world oil market and geopolitics will also shape the path toward or away from cooperation. A look back at history sheds light on the important role of cooperation—or lack thereof—in shaping the outcome of key periods of Canadian-American energy relations.

- **Cooperation—1940s to 1973**
  - During World War II, when the United States was the main supplier of oil to Canada, cooperation led to the border's being "ignored in order that necessary programs might be carried forward with a minimum of dislocation and inefficiency."*

*Paul Chastko, *Developing Alberta's Oil Sands*, quoting from *A History of the Petroleum Administration for War: 1941–45*, Washington, Government Printing Office.

- In the late 1940s the Canadian oil industry blossomed because of investment by American oil companies. Canada then became an exporter of oil to the United States.

- In the late 1950s further growth in Canadian oil production was under threat due to US import restrictions. In 1959 the administration of US President Dwight Eisenhower exempted Canada from an import quota, despite a large surplus of US oil production capacity, to enhance what was explicitly seen as North American energy security.

- In 1969, as oil production grew in the western provinces, the Canadian government sought assurance of greater access to the US market.

• **Strained relations—1973 to 1989**

- The 1973 oil embargo ushered in a tumultuous period for US-Canada oil relations and a more nationalistic era. Canada raised the price of oil for US buyers—in line with OPEC prices—but subsidized domestic prices. Taxes on oil companies increased, and pressure grew for greater Canadian ownership of domestic oil companies. These developments constrained investment. The net effect was a decline in Canadian oil production from 2.1 million barrels per day (mbd) in 1973 to 1.6 mbd in 1976—a 24 percent drop in three years.

- In 1975 Canada became a net oil importer. Tense oil relations complicated discussions aimed at building a pipeline to ship Alaskan and northern Canadian gas to the United States. This pipeline still has not been built.

- In 1980 the government of Prime Minister Pierre Trudeau introduced a National Energy Program that created incentives for increasing Canadian ownership of the still largely American-owned petroleum industry. This change added to ongoing weakness in oil production, and Canada remained a net oil importer until 1983.

• **Renewed cooperation—1989 to present**

- In 1989 a free trade agreement between the United States and Canada marked a return to cooperation and integration of energy markets by enshrining the "fullest possible" trade in energy. The pact forbids the Canadian government from imposing higher prices for exported oil and gas relative to the domestic market price.

- The US-Canada free trade agreement laid the groundwork for the 1993 North American Free Trade Agreement (NAFTA), which reaffirmed the oil and gas trading framework between Canada and the United States. Investment and trade flows of oil and gas have grown since the agreements were adopted. For example, Canadian crude oil exports to the United States doubled from 1993 to 2008.

## New Challenges to the US-Canada Energy Relationship

Will Canada and the United States continue to cooperate on energy issues, including environmental matters? Early signs point toward a partnership in developing a common framework for reducing GHG emissions—an issue of critical importance to oil sands investment. In February 2009 the US-Canada Clean Energy Dialogue was established, a high-level forum to pursue cooperation on clean energy and environmental matters. Reducing the GHG emissions from fossil fuels will be an important issue. US President Barack Obama, just before his maiden trip to Canada, said, "I think it is possible for us to create a set of clean energy mechanisms that allow us to use things not just like oil sands, but also coal."

A common framework for regulating GHG emissions would provide a more clear and solid investment climate for oil sands investors than a world with conflicting regulatory schemes. An integrated approach would help to reduce market distortions and trade conflicts. However, the challenge of developing a shared set of policies should not be taken lightly. The United States and Canada have a history of cooperation on addressing emissions from conventional pollutants, such as sulfur dioxide and nitrogen oxides. Developing a truly integrated approach between the United States and Canada for regulating GHG emissions would be a major milestone for international cooperation to combat climate change. The low-carbon fuel standards currently under discussion at both the federal and state levels in the United States could be part of a cooperative climate change scheme if Canada adopted similar regulations or could be an impediment to cooperation if they are only adopted on the American side.*

The United States and Canada achieve some measure of cooperation on regulating GHG emissions in all three CERA scenarios: New Social Order, Barreling Ahead, and Deep Freeze. However, the agreement is early and wide-ranging in New Social Order and late and limited in Deep Freeze. Barreling Ahead lies between these two extremes with respect to Canadian-American cooperation on GHG emissions.

## FEDERAL AND PROVINCIAL GOVERNMENTS' CHANGING FOCUS

**Key question: How will federal and provincial regulation of oil sands evolve over time?**

**Why it matters: Oil sands developments in Alberta are subject to a complex web of regulation. The regulatory environment can slow or accelerate the pace of development of oil sands projects, and it largely determines the degree of environmental protection included.**

*A federal law in the United States may affect a small portion of the US market for oil sands products, but its interpretation is uncertain. Section 526 of the Energy Security and Independence Act of 2007 prevents the US government from buying fuel produced from "nonconventional petroleum sources" with life-cycle GHG emissions greater than fuel produced from "conventional petroleum sources." The definitions of "nonconventional" and "conventional" are unclear, and thus it is not clear whether the provision applies to products produced from Canadian oil sands.

## Federal and Provincial Regulatory Agencies

Regulatory oversight of oil sands involves a number of entities, including several provincial agencies, due to the complex issues involved. The Alberta Ministry of Energy is responsible for energy policy and strategy, while the Energy Resources Conservation Board (ERCB) is responsible for regulation. The Ministry of the Environment is responsible for safeguarding and enhancing Alberta's environment and for developing Alberta's Climate Change Strategy. Alberta's legislature passed a law that requires facilities that emit more than 100,000 metric tons of carbon dioxide ($CO_2$) per year to reduce their emissions intensity by 12 percent below their 2003 baseline. Although Alberta was one of the first regions to establish emissions limits in North America, its policy is far less stringent than those being discussed at the federal level in both Canada and the United States. The provincial Ministry of Sustainable Resource Development is charged with managing the province's public lands, forests, fish, and wildlife.

The federal government also plays an important role in oil sands regulation. Environment Canada, the federal ministry, has jurisdiction in many areas affecting water and air quality, particularly where these issues cross provincial borders. Through its Canadian Environmental Assessment Agency it works with the ERCB as part of a joint review process for oil sands projects to address their long-term environmental impacts. Environment Canada is also responsible for developing a climate change strategy at the federal level. The Department of Fisheries and Oceans has some jurisdiction over water quality and use. Finally, Natural Resources Canada and its regulatory arm, the National Energy Board, regulates construction, expansion, and tariffs on interprovincial and international pipelines that carry oil, natural gas liquids, and natural gas. It is also responsible for authorizing short-term orders for all oil exports and both short- and long-term orders for natural gas.

## Shift in Regulatory Focus

Through the 1990s federal and provincial regulation of oil sands aimed to foster growth to maximize economic benefits for Alberta and Canada as a whole. In 1995 the National Oil Sands Task Force, a group including representatives from government, oil companies, unions, and municipalities, focused on how to increase investment in the oil sands, with a goal of producing 1.2 mbd by 2020. The Alberta government reduced royalties to as little as 1 percent, and the federal government provided strong income tax incentives. At first little investment resulted, but increasing oil prices and improvements in oil sands technology brought explosive growth after 2000. Oil sands production reached the goal of 1.2 mbd in 2007, a full 13 years ahead of the task force's goal.

Oil sands developments have always gone through a comprehensive project-specific evaluation of their economic, environmental, and social impacts. This project-by-project model of regulation served the industry and public well when there were fewer developments. However, the scale of development and the number of projects have increased dramatically since 2000, raising questions about the cumulative impact of all oil sands development. The Cumulative Environmental Management Association, created in 2000, was the first multistakeholder group to attempt reconciliation of the overall impact of multiple projects on the region's environment. The group's work continues, but several environmental nongovernmental organizations and First Nations have resigned from the group over what they saw as a lack of progress in managing the oil sands' cumulative impact.*

The Alberta Treasury Board created the Oil Sands Sustainable Development Secretariat in 2007 to specifically address rapid growth in oil sands development. It collaborates with other ministries, industry, communities, and various stakeholders to address social, infrastructure, environment, and economic impacts of oil sands developments. The Secretariat set forth its long-term sustainability agenda in *Responsible Actions: A Plan for Alberta's Oil Sands*, released on February 12, 2009. The plan's key objectives are to reduce the environmental footprint of oil sands, optimize economic growth, and increase quality of life for Albertans today and in the future. The plan also seeks to leverage the bitumen royalty regime to encourage construction of upgraders in Alberta and to focus oil sands research on more sustainable practices.

The Alberta government has also responded to concern about oil sands' cumulative impacts over the past year with new regulations and initiatives in the areas of land use, air emissions, tailings management, and water use. The Ministry of Energy recently issued a new energy strategy for the province. The Ministry of Sustainable Resource Development's new Land Use Framework is a step forward in thinking about sustainable development in the oil sands. The Framework includes an outcome-based approach to land development, the consideration of cumulative effects management in development decisions, and an effort to resolve potential conflicts between alternate uses of land. The ERCB has also issued several new and proposed regulations governing water use and mining waste management. All represent a shift toward requiring more sustainable growth.

Alberta also changed its oil sands royalty rates at the beginning of 2009. Royalties are now determined on a sliding scale based on West Texas Intermediate (WTI) prices. When WTI prices are between $55 and $120 per barrel, royalty payments range from 1 to 9 percent for operators that have not yet recovered their capital costs and 25 to 40 percent for operators that have recovered their capital costs. At today's oil prices of less than $55 per barrel, royalty payments have remained the same as before the policy change. Additionally, the Alberta government is moving forward with a plan to accept bitumen-in-kind for royalty payments. This bitumen will be sold to upgraders in Alberta to assure that value-added upgrading occurs within the province.

## What Will the Future Bring?

Sustainability is likely to remain a key theme of future oil sands regulation. Pressure to introduce more regulations is not likely to fade, even with the decline in oil prices since 2008. Regulations focused on sustainable development are particularly prevalent in the New Social Order scenario. The low growth path envisioned in the Deep Freeze scenario makes further regulation less necessary.

*The members of the Cumulative Environmental Management Association that resigned were the Pembina Institute, the Toxics Watch Society of Alberta, the Fort McMurray Environmental Society, the Athabasca Chipewyan First Nation, and the Mikisew Cree First Nation.

Much of the oil sands area has already been leased to operators, but the province has an opportunity to take back leased land when the leases expire. This possibility is more likely under the strict regulatory environment of the New Social Order scenario. Typical oil sands leases are 15 years, although some older leases are as long as 21 years. If the land is not explored for oil production potential or developed during the lease term, the lease expires, and the land is returned to the Alberta government. Although some developers have negotiated an extension of the lease, the expiry date represents an opportunity for the government to take back some of the leased lands. Leases expire in the next five years for 18 percent of the total leased land area and in the next ten years for 33 percent of the leased land area.

Additionally, more data collection is needed to properly assess some environmental impacts, including site reclamation for mining projects, water use and pollution, and the cumulative impacts of the industry as a whole. Continuing focus by the regulatory authorities and industry on the cumulative impacts of oil sands development could lead to reduced environmental and social impacts and improved public perception of the industry.

## FIRST NATIONS GROUPS AND TREATY RIGHTS

**Key question: How will the exercise of First Nations rights in the oil sands evolve over time?**

**Why it matters: First Nations groups must be consulted on all development within the oil sands area. The nature of this consultation is under debate, and several lawsuits are under way to challenge how First Nations groups are consulted prior to oil sands development.**

In 1899 the British government signed Treaty 8 with First Nation groups.* The treaty requires the Canadian government to consult First Nations on any activities that have the potential to affect their traditional way of life, including rights to hunt and fish, in an area of about 842,000 square kilometers (325,000 square miles). This area includes northern Alberta and parts of British Columbia and Saskatchewan, and extends into the Northwest Territories as far north as Great Slave Lake. The treaty includes about 8 percent of Canada's total land area and covers the entire region of the Athabasca oil sands. Approximately 100,000 people of First Nations heritage reside in Alberta.

Under the treaty First Nation rights to traditional land use can be infringed upon given other activities on treaty land, but the government must consult with the First Nations prior to making a decision to proceed with the disruptive activity. In 1930 the natural resources in Alberta were transferred from the federal government to the provincial government, and the obligation to consult with First Nations groups under Treaty 8 transferred to the province as well.

*First Nations groups are indigenous residents of Canada that live south of the territory occupied by the Inuit people, a culturally and linguistically separate group of indigenous Canadians. The Métis are people of mixed indigenous and European heritage. These three groups together constitute Canada's Aboriginal population.

The Alberta government does not engage in a consultation process for individual projects on treaty land. In the case of oil sands developments, the developing companies are required to consult First Nation groups directly and discuss, as well as mitigate to the extent possible, the impacts on First Nations' rights and traditional land uses. Both companies and First Nation groups are working to better understand and define "consultation." Many people on both sides believe that the Alberta government should play a more active role in the consultation process, helping to standardize the process and make the obligations on both sides more clear.

Several projects in treaty areas have been delayed or canceled due to a lack of proper consultation with First Nations groups. These include an injunction against the development of a billion-dollar hydropower development project in Quebec and the delay of the Mackenzie Valley pipeline. Delays are not limited to large, high-profile projects. In the oil sands region the Mikisew Cree First Nation in Fort Chipewyan won a legal action regarding a winter road through Wood Buffalo National Park that was approved without consultation.

The definition of consultation in the oil sands region is evolving, with three ongoing lawsuits challenging the way First Nations groups are consulted prior to oil sands projects. Two of these lawsuits challenge the Government of Alberta's right to grant oil sands leases to oil companies without consulting First Nations. Currently First Nations groups are consulted only after the land is leased to oil companies and the specific project planned for the area is defined. The third lawsuit challenges the consultation process on a specific project.

The outcome of these lawsuits and other engagement between the oil sands industry and First Nations groups has the potential to change the scope and pace of oil sands development. Cooperative engagement that meets the needs of industry and First Nations groups will be necessary to achieve the rates of growth envisioned in the Barreling Ahead scenario and the early years of the New Social Order scenario. This cooperation could occur through the intervention of the Alberta government, or perhaps through the formation of a negotiating body composed of oil sands producers. The low level of oil sands development envisioned in the Deep Freeze scenario lessens the impact of development on First Nations groups.

## LOCAL COMMUNITY STRUGGLES TO KEEP UP WITH OIL SANDS DEVELOPMENT

**Key question: How can the local community around the oil sands cope with the boom-and-bust cycle of development?**

**Why it matters: The remote nature of the oil sands region makes attracting and retaining workers difficult. The recent boom in oil sands activity has added to the challenge of providing community services to a rapidly growing population.**

The rapid development cycle of oil sands development is difficult for local government to manage. The boom over the past several years caused many problems in the Regional Municipality of Wood Buffalo, where the majority of oil sands projects are located, and in Fort McMurray, the urban center of the oil sands region. Slowing investment in oil sands today could give the region a chance to catch up with the population growth of the past several years, or it could result in infrastructure construction for the next boom that never arrives. The region's dependence on one volatile industry makes planning a guessing game.

From the mid-1980s to the late 1990s little economic growth occurred in the region because of low oil prices, and population was nearly static. However, from 2000 to the present the population of Fort McMurray grew from approximately 42,000 to almost 70,000 as activity in the oil sands exploded along with oil prices. This population figure does not include the "shadow population" of temporary workers in camps and those who reside and work in the area part time, estimated at 25,000 at its height during summer 2008.

This rapid growth brought challenges for every type of infrastructure and community service in the area. Fort McMurray has become a boomtown, with all the escalating costs and quality-of-life issues that boomtowns face. Housing is in short supply, and Fort McMurray has been among the most expensive rental and real estate markets in Canada. The high cost of living means that the region has difficulty attracting and retaining workers for occupations apart from oil sands, including health care workers, teachers, and municipal employees. The health region that encompasses the Regional Municipality of Wood Buffalo has the lowest ratio of doctors to population in rural Alberta. Teacher turnover in the Fort McMurray public school system is 29 percent per year, compared with 4.5 percent in Edmonton.

Infrastructure is inadequate for the growing population. The water treatment plant and wastewater treatment plant need expansion immediately, and the solid waste landfill is nearly full. Highway 63 connects the oil sands region to Edmonton, 435 kilometers (270 miles) to the south. The road has only two lanes for most of its length and is notorious for traffic backups and deadly accidents, with 22 fatalities in 2007 and 6 people killed in a single day in three separate accidents in January 2009. Expansion of the road to four lanes is under way and complete for short sections, but a completion date for the entire highway is unknown.

Remedying these infrastructure shortfalls is particularly expensive in the Fort McMurray area, where construction costs have recently been two to three times the provincial average because the region is remote and because municipal projects compete with oil sands projects for labor and equipment. The high costs and sheer volume of work needed caused Alberta to modify the debt ceiling for the Regional Municipality of Wood Buffalo in 2006 to allow it to borrow more money than any other municipality in the province. Still the question remains, If low oil prices continue to reduce investment in oil sands, will these infrastructure investments be needed? Unemployment in Fort McMurray, unheard of as recently as summer 2008, is creeping upward as oil sands projects are delayed.

The fate of communities in oil sands area differs greatly across the three CERA scenarios. In Barreling Ahead so many workers come to the area that the province helps establish satellite communities outside Fort McMurray to house workers closer to their jobs and help minimize work camps. Additionally a portion of the large royalty revenues generated by Alberta is diverted back to the oil sands area to improve infrastructure and community services. Community growth is more manageable in the New Social Order scenario. Fort McMurray would likely shrink in the Deep Freeze scenario, as the lack of new project starts reduces the need for labor.

# CHAPTER III: CRITICAL ISSUES FOR OIL SANDS DEVELOPMENT

# CHAPTER III: CRITICAL ISSUES FOR OIL SANDS DEVELOPMENT

Development of the oil sands poses a number of challenges and questions. This chapter identifies critical areas of uncertainty or disagreement that are central to the future development of the oil sands industry in Alberta. Our goal is to illustrate these complex issues clearly to identify what is known and what is unknown, and to provide a common understanding and platform for discussing the contentious issues that affect oil sands development. The facts are in dispute for some of these issues; for others the questions are about future costs or technological advancement. Each of these issues has the potential to change the course of oil sands development.

## ENVIRONMENTAL ISSUES

The environmental issues surrounding oil sands development are among the most visible and controversial. There are growing concerns in Canada, the United States, and around the world about the impact of oil sands development on the environment. However, rigorous and transparent comparisons of the environmental impact of oil sands with those of other sources of energy are in short supply. Greenhouse gas (GHG) emissions are a contentious issue, and estimates of the emissions difference between oil sands and more conventional fuels vary widely. Water management is also crucial. The oil sands mines take nearly all of their water from the Athabasca River, an ecologically important water body; in-situ production relies mostly on fresh and brackish groundwater, and the hydrogeology in the entire region is not well understood. Oil sands production, particularly mining, affects many square miles of land and produces considerable quantities of waste material. Many stakeholders, especially local residents, are concerned about companies' ability to manage these impacts and their ability to restore the landscape when mining is finished.

A recent survey of Canadians found that a substantial majority believed that there are more benefits than drawbacks for Canada from oil sands development, but 35 percent of Canadians saw more drawbacks than benefits.* Canadians seek a balance between the economic benefits of oil sands development and the environmental impacts of that development.

### Greenhouse Gas Emissions

**Key question: How do the GHG emissions of Canadian oil sands compare with other sources of crude oil? Is current data on GHG emissions transparent enough to support the adoption of sound public policy?**

**Why it matters: Canadian oil sands face a greater risk from climate change regulations because their GHG emissions are greater than many, but not all, sources of oil consumed in the United States. Transparent reporting requirements for all energy producers would ensure that all sources of liquid fuel, including oil sands, are considered fairly.**

*Harris/Decima, *Oil Sands a Concern, but Yield More Benefits than Drawbacks for Canada,* Alberta, March 2, 2009.

Policies to reduce GHG emissions will put pressure on all producers of fossil fuels. However, Canadian oil sands face greater risk from such policies because of their relatively greater life-cycle GHG emissions compared with the average crude oil consumed in the United States.

Life-cycle assessments aim to quantify the GHG emissions of fuels along the entire value chain. For oil, this means accounting for all of the emissions that occur—from the production well through combustion of the final refined product. Key inputs for evaluating the life-cycle GHG emissions of petroleum fuels are

- the amount and type of fossil energy used in crude oil production
- GHG emissions resulting from vented or flared associated gas during crude oil production
- the amount and type of energy used in refining, which varies by refinery configuration, crude oil type, and refined product produced
- the distance and amount of energy used for transporting the fuel
- the carbon content of the refined product that is consumed

To evaluate the life-cycle GHG emissions of conventional and unconventional crude oils, we did not conduct our own original well-to-wheels study. Instead, CERA did a meta-analysis of 11 publicly available life-cycle studies and compared their results on an "apples-to-apples" basis. This meta-analysis assessment highlighted the wide range of estimates regarding emissions and energy use along the oil value chain and the need for more transparent data and accounting methods.

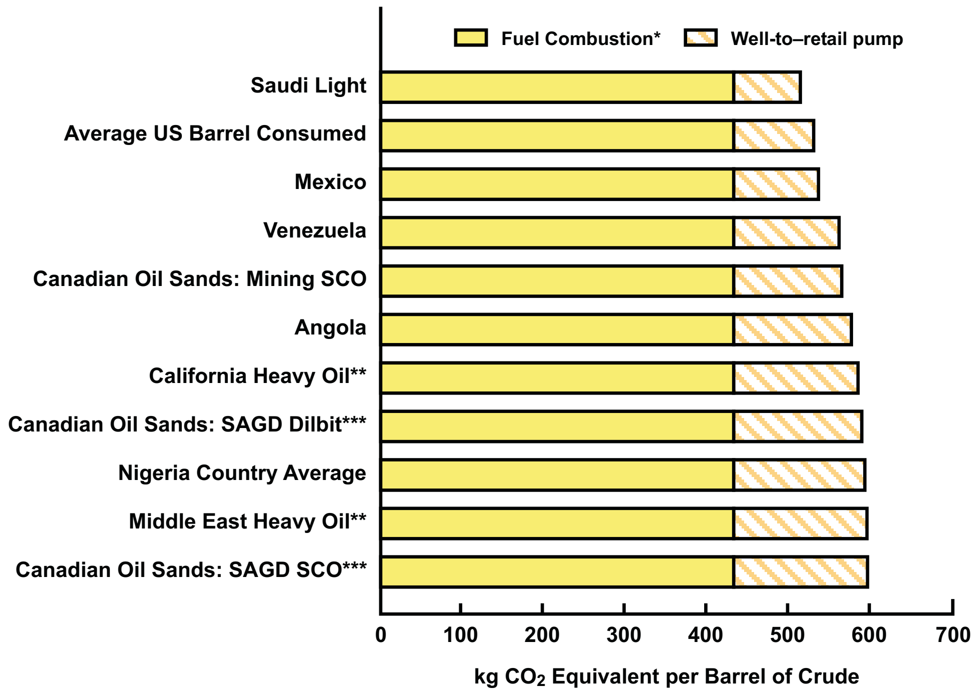
When GHG emissions are viewed on a life-cycle basis (well-to-wheels), the emissions released during the combustion of refined products (such as gasoline and diesel) make up 70 to 80 percent of total emissions.* The emissions associated with the final portion of the value chain are not related to the origin of the crude—for example, tailpipe GHG emissions from an automobile are the same whether the source of gasoline is Nigerian light crude, West Texas Intermediate crude (the famed WTI), or Canadian oil sands. Variability in life-cycle emissions among petroleum fuels occurs mainly in the well-to–retail pump portion of the value chain—the portion upstream of the vehicle tank (see Figure III-1).** Consequently, much of the public debate about oil sands emissions focuses on this segment although this constitutes a relatively small part of total GHG emissions.

Among sources of crude oil, emissions for the well-to–retail pump portion of the value chain differ because of varying energy requirements for crude oil production, upgrading, transport, and refining. However, in many life-cycle analyses, emissions for oil sands are compared against a single average "conventional crude oil." In reality the picture is more

*Well-to-wheels covers all GHG emissions from the production, processing, and distribution of oil and refined products and the combustion of refined products.
**Well-to–retail pump covers GHG emissions from oil production, processing, and distribution of refined products to the retail pump. It excludes combustion of refined products.

**Figure III-1**

**Life-cycle Greenhouse Gas Emissions for Various Sources of Crude Oil**

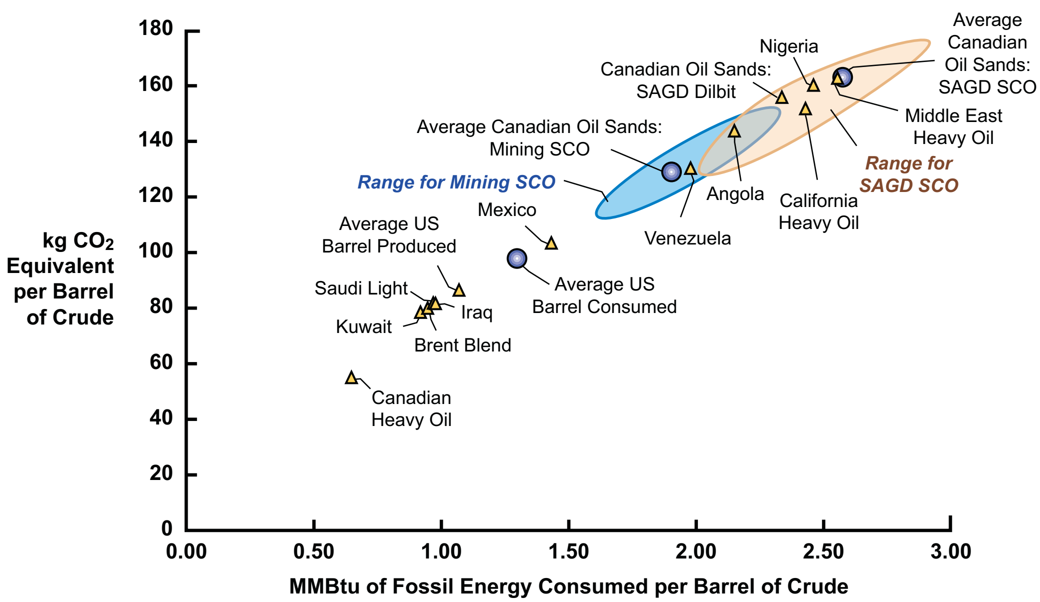



Source: Cambridge Energy Research Associates.
*The life-cycle GHG emissions estimate is based on a per barrel of crude basis, assuming an average carbon content. To convert this to a refined product basis, such as gasoline or diesel, additional assumptions would be needed to apportion well-to–retail pump emissions to individual refined products. This depends on the product slate associated with individual crude sources and refinery-specific configurations.
**Assumes steam-assisted gravity is used for production.
***Assumes a steam-oil ratio of 3.
Data source: Collected from a range of published reports that include th reports listed below, industry sources, and other published reports.
DOE/NETL: "Development of Baseline Data and Analysis of Life Cycle Gas Emissions of Petroleum-Based Fuels," November 2008.
McCann and Associates: "Typical Heavy Crude and Bitumen Derivative Gas Life Cycles," November 2001.
RAND: "Unconventional Fossil-Based Fuels: Economic and Environme 2008.
NEB: "Canadian Oil Sands: Opportunities and Challenges," 2006.
CAPP: "Environmental Challenges and Progress in Canada's Oil Sands
GREET: Version 1.8b, September 2008.
GHGenius: 2007 Crude Oil Production Update, Version 3.8.
Syncrude: "2007 Sustainability Report."
Suncor: "2007 Report on Sustainability."
Shell: "The Shell Sustainability Report, 2006."
CERA /IHS data.
Report results were modified to represent a uniform system boundary a
When a single country is named, it represents an average country valu
90107-8

complex. Figure III-2 and Figure III-3 illustrate the well-to–retail pump GHG emissions for several sources of crude oil. The average well-to–retail pump emissions for crude oil consumed within the United States are also shown in Figure III-2.* Variability in GHG emissions arises from attributes of the crude oil itself and the oil field where it is produced. Important attributes include the heaviness of the crude oil (API gravity), the oil field's age, and the extraction technology utilized. For example, over the life of an oil field the energy consumed to extract a barrel of oil can increase more than four times, due to the need for more energy-intensive extraction techniques as the reservoir ages and the natural reservoir

**Figure III-2**

**Well-to–retail pump Greenhouse Gas Emissions: A Comparison of Results from Published Reports**

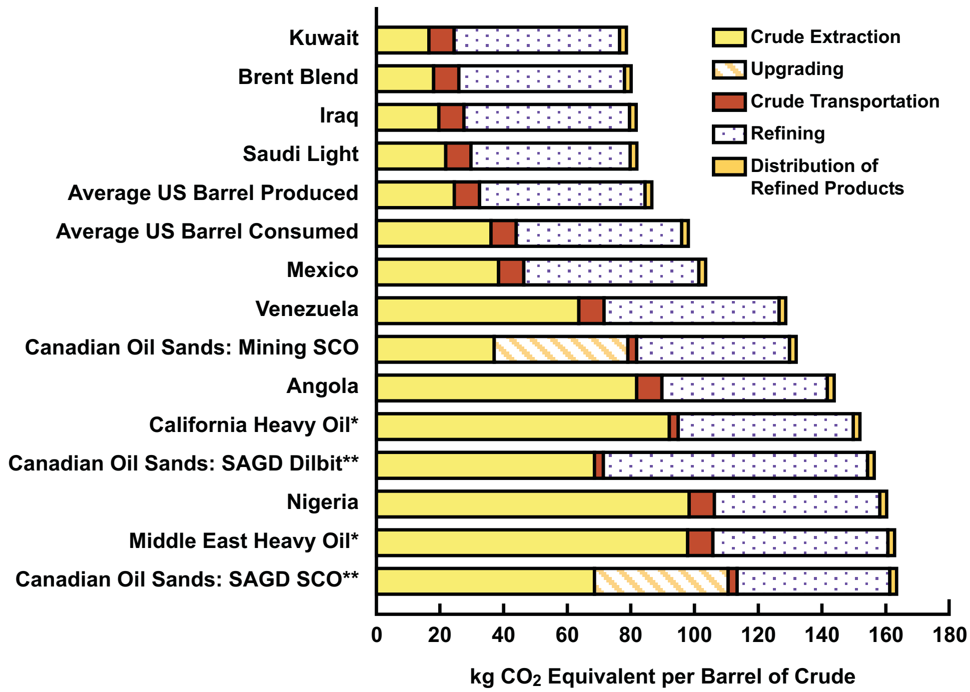



Source: Cambridge Energy Research Associates.
Data source: Collected from a range of published reports that include the reports listed below, industry sources, and other published reports.
DOE/NETL: "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008.
McCann and Associates: "Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles," November 2001.
RAND: "Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs," 2008.
NEB: "Canadian Oil Sands: Opportunities and Challenges," 2006.
CAPP: "Environmental Challenges and Progress in Canada's Oil Sands," 2008.
GREET: Version 1.8b, September 2008.
GHGenius: 2007 Crude Oil Production Update, Version 3.8.
Syncrude: "2007 Sustainability Report."
Suncor: "2007 Report on Sustainability."
Shell: "The Shell Sustainability Report, 2006."
CERA /IHS data.
Report results were modified to represent a uniform system boundary and units.
When a single country is named, it represents an average country value.
90107-9

*The average is specified in *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, published by the US Department of Energy in November 2008.

Figure III-3

Well-to–retail pump Greenhouse Gas Emissions by Process




Source: Cambridge Energy Research Associates.
*Assumes steam-assisted gravity is used for production.
**Assumes a steam-oil ratio of 3.
Data source: Collected from a range of published reports that include the reports listed below, industry sources, and other published reports.
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Shell: "The Shell Sustainability Report, 2006."
CERA /IHS data.
Report results were modified to represent a uniform system boundary and units.
When a single country is named, it represents an average country value.
90107-27

pressure declines. GHG emissions from the refining of crude oil can also vary by as much as 15 percent, depending on the heaviness of the crude oil processed and the complexity of the refinery.

GHG emissions associated with Canadian oil sands are generally higher than the average crude consumed in the United States because a significant amount of energy, typically natural gas, is used to extract the bitumen from the sand and upgrade it. Bitumen does not flow naturally and requires energy to be upgraded from a low-value solid to a high-value liquid fuel. However, Figure III-2 also highlights other sources of crude oil with high well-to–retail pump GHG emissions: Venezuelan heavy crude oil, Nigerian crude oils, and crude oils from mature assets that require steam for enhanced oil recovery.* This last group includes domestic resources such as California heavy oil and certain fields in the Gulf of Mexico and the Middle East.

The range of GHG emissions associated with Canadian oil sands development is quite large (see the shaded area on Figure III-2). Some analyses have asserted that Canadian oil sands have well-to–retail pump emissions many multiples higher than the average crude oil consumed in the United States. This is not true of the typical or average oil sands development or even of the more energy-intensive oil sands projects. For example, CERA's comparison of publicly available life-cycle analysis studies found that fuel produced from oil sands mining has average well-to–retail pump emissions 1.3 times the average for fuel consumed in the United States. Similarly, fuel produced from oil sands utilizing steam-assisted gravity drainage (SAGD) has average well-to–retail pump GHG emissions about 1.7 times larger than the average fuel consumed in the United States today. SAGD tends to have higher life-cycle GHG emissions than mining operations because of the significant amount of steam that must be produced for in-situ extraction.

The well-to–retail pump comparison shown in Figure III-2 makes GHG emissions from oil sands and other high-emitting crude oils appear quite large, but the difference between oil sands and the average crude consumed in the United States is significantly smaller when full life-cycle, well-to-wheels emissions are shown (see Figure III-1). Fuel produced from mined oil sands has about 5 percent greater well-to-wheels emissions than the average fuel consumed in the United States. Similarly, fuel produced from a SAGD project with a steam-oil ratio (SOR) of 3 has life-cycle emissions about 15 percent greater than the average fuel consumed in the United States.

Evaluating and comparing the life-cycle GHG emissions of fuels is a very complex process given the differences in the data used and in the types of inputs considered. Averages attained from rules of thumb or broad assessments can be helpful for general discussion, but they are not nearly specific enough to support sound public policy. More accurate measurement, verification, and reporting requirements are important components of policy development and implementation. For example, nearly all fossil fuel power plants in the United States have continuous emissions monitoring systems installed. These systems provide hourly data on a unit-by-unit basis and are likely to play an important role in tracking GHG emissions and costs for the power sector. To ensure the integrity of any future emissions regulatory regime, similar reporting requirements may emerge for the oil and gas sectors.

Furthermore international data must be accurate and verifiable. Without such a guarantee, Canadian oil sands could be unduly penalized for being more transparent about their GHG emissions. Policies that limit GHG emissions are likely to be costly. If future policies target life-cycle emissions, having accurate information will be crucial. Otherwise, policies that seek to reduce emissions could instead shift emissions to countries or sectors with mischaracterized levels of GHG emissions.

*GHG emissions of Nigerian crude oils are higher than many other sources because of the venting and flaring of associated natural gas during production.

Regardless of the comparison to other forms of energy, total GHG emissions related to the oil sands will rise as production increases. In all three of CERA's scenarios, production rises, although to varying degrees. In addition, the pace of efficiency gains (such as lower SORs) and the commercial success of carbon-mitigation technology will influence how steeply oil sands–related GHG emissions rise. The commercial development of oil sands has involved major technological innovation. Future development will almost certainly place significant emphasis on reducing GHG emissions.

## Water Use and Availability

**Key questions: How does the water use for production of Canadian oil sands compare with that for other sources of liquid fuels? Is enough water available to support current and future oil sands production?**

**Why it matters: Water is a critical input to oil sands production; and protecting the ecology of the Athabasca River and preventing groundwater depletion are also crucial.**

The water use of oil sands projects has become a contentious issue, and oil sands are frequently identified as a water-intensive resource. However, oil sands are not alone in their water intensity; many types of energy production use a great deal of water. Figure III-4 depicts the water use of several liquid fuel and electricity production methods on an equivalent energy basis. Net water use in oil sands production today averages about four barrels of water per barrel of bitumen for mining operations and 0.9 barrels of water per barrel of bitumen for in-situ production.* Conventional oil uses about 0.1 to 0.3 barrels of water per barrel of oil produced, while oil produced through enhanced oil recovery can use up to 70 barrels of water per barrel of produced oil. Oil alternatives can also be water intensive: ethanol produced from irrigated crops such as corn can use more than 300 barrels of water per barrel of ethanol, and coal-to-liquids can use ten barrels of water per barrel of finished product.**

From an environmental perspective, adequate local water availability for oil sands production is more important than the amount of water used per barrel produced. The water intensity and rapid growth of oil sands production raises the question of whether there is enough water available to meet the industry's current and future needs without causing environmental damage.

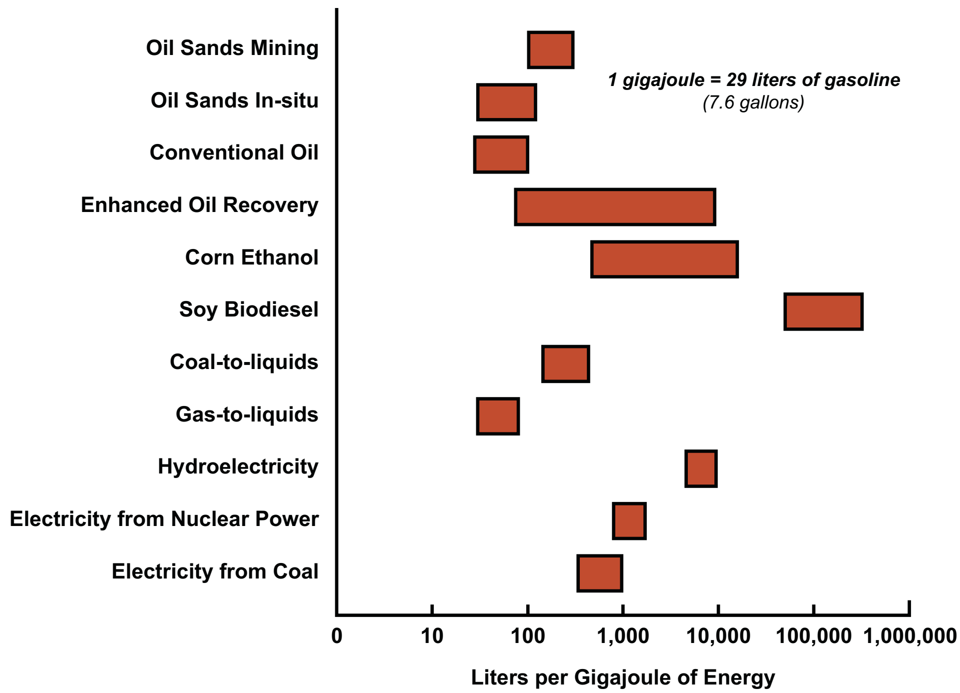
### *Mining Water Use*

Water for oil sands mining and local upgrading comes primarily from the Athabasca River, with additional volumes from site runoff and mine dewatering. All water that contacts mining-affected areas is held on site, including process water and runoff due to precipitation. No

*Net mining water use includes water from site runoff and mine dewatering, in addition to water from the Athabasca River. River withdrawals are approximately 2.5 barrels of water per barrel of bitumen.
***Thirsty Energy: Water and Energy in the 21st Century.* World Economic Forum, in partnership with Cambridge Energy Research Associates, 2009.

**Figure III-4**

**Life-cycle Water Use of Various Energy Sources**




Source: Cambridge Energy Research Associates, US Department of Energy.
90107-28

water is intentionally released back to the Athabasca River.* The Athabasca River originates in Jasper National Park and flows north through the oil sands region to the Peace-Athabasca Delta and into Lake Athabasca. Its waters then flow through the Slave and Mackenzie Rivers into the Arctic Ocean. The Peace-Athabasca Delta is one of the most important nesting and migration staging areas for waterfowl in North America and is mostly protected by Wood Buffalo National Park.

The Athabasca River is seasonal with low winter flow—the average flow from April through November is nearly five times the average flow from December through March. Thus, oil sands water consumption during the winter is of particular concern, although maintaining high flow during the summer is also important to ecosystem health. Phase I of the Athabasca River Water Management Framework, implemented by Alberta Environment and the federal Department of Fisheries and Oceans in July 2007, sets limits on water withdrawals from the river to minimize negative effects on the ecosystem. At no time may withdrawal by all users, including oil sands, exceed 5.2 percent of median river flow. An instantaneous withdrawal limit of 15 cubic meters ($m^3$), or (3,960 gallons) per second is also in place during low-flow conditions in the winter, and a limit of 21 $m^3$ (5,548 gallons) per second is in place

*Some process-affected water may reach the Athabasca River because of seepage from tailings ponds, as discussed in a later section.

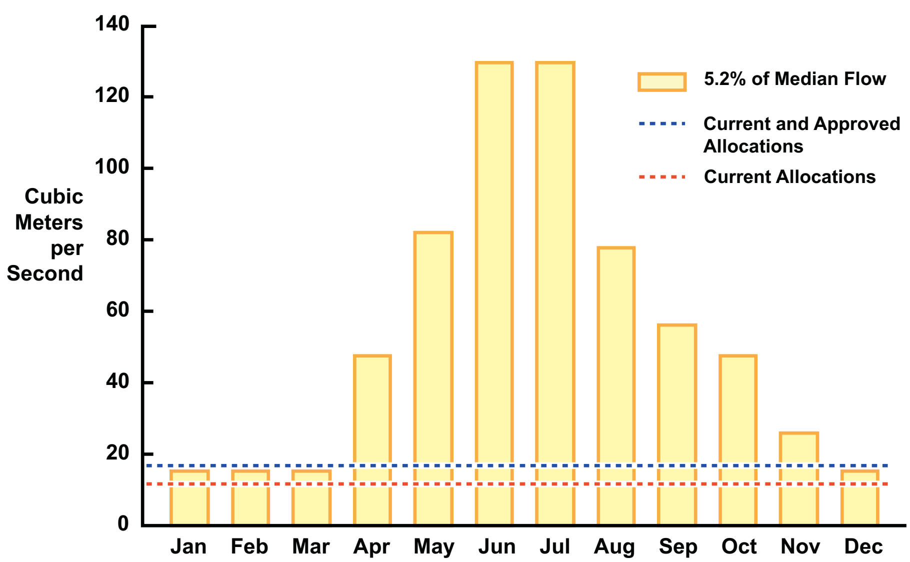
at all times. To date none of these limits have been binding on oil sands operators, but the amount of water allocated to users of the Athabasca is approaching these withdrawal limits (see Figure III-5). A second phase of the river management framework process is ongoing. The withdrawal limitations in place today will be reviewed and possibly adjusted no later than September 2010.

Projects planned for the future will allocate on an annual basis more river withdrawals than can be sustained during the winter months (see Figure III-5). Water is allocated from the river based on a total level of annual withdrawal. However, withdrawal limits during the winter will prevent operators from withdrawing water at their allocated average flow rate, as shown in Figure III-5. Thus, new mines under construction include facilities to store water during the summer months to allow continued operation when water flow from the Athabasca is restricted. Better management of mining waste will also reduce the amount of water required from the Athabasca River, as described in the following section. Finally, the volume of water that the mines actually use today is less than the allocated volume (see Figure III-6). The amount of water that the mines use changes over time, with especially high water use during expansion and start-up of new portions of the mine.

In the high growth Barreling Ahead scenario the mines are likely to use nearly all of their allocated water, and water storage will be particularly important. Production growth is lower in the New Social Order and Deep Freeze scenarios, with a corresponding decrease in stress on the Athabasca River and the need for water storage.

**Figure III-5**

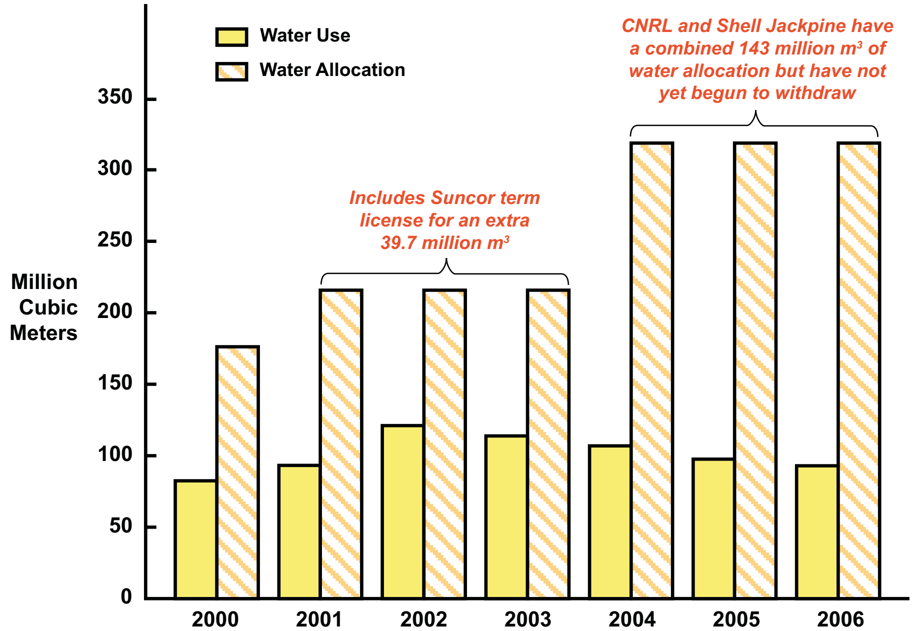
**Athabasca River Flow:**
**5.2 Percent of Median Flow Compared to Allocated Withdrawals**




Source: Cambridge Energy Research Associates;
water flow and allocation data from Alberta Environment.
90107-10

**Figure III-6**

**Oil Sands Mining Actual Water Use and Allocation from the Athabasca River**




Source: Cambridge Energy Research Associates; water use and allocation data from Alberta Environment.
90107-29

### *In-situ Water Use*

Groundwater is the primary water source for in-situ oil sands production. The amount of water used for in-situ production depends on the amount of steam injected into the ground per volume of oil produced, known as the SOR, and the percentage of that water that can be recovered and recycled. The amount of water used in in-situ oil sands extraction has been decreasing over time. Operators have a strong incentive to decrease their water use and SOR because these changes in turn decrease their water treatment and steam production costs.

Use of salty water from deep aquifers, known as brackish groundwater, is becoming more common, but it has benefits and drawbacks. Using brackish water conserves freshwater resources for other uses, such as irrigation or drinking. Withdrawing groundwater from deep brackish aquifers also does not require a permit, although the volume withdrawn must be reported to Alberta Environment. On the other hand, brackish water requires more treatment than fresh to be used for oil sands production, because the silica, hardness, and salinity of the brackish water foul the steam-producing boilers. Use of brackish water thus results in higher water treatment costs, greater energy use, and greater amounts of waste generated by the water treatment process. A draft directive from the ERCB and Alberta Environment regulates water recycling in in-situ production, requiring a greater proportion of produced water to be recycled if only freshwater is used than if both fresh and brackish water are used.

Availability of groundwater, both brackish and fresh, for oil sands operations should not be taken for granted. The hydrogeology of freshwater aquifers in the oil sands area is complicated and poorly understood because of their hydraulic connection to the wetland environment of the boreal forest. These shallow freshwater aquifers are renewable, meaning that they will recharge from precipitation and surrounding water bodies when pumping ends. Determining the rate of water withdrawal from these aquifers that does not damage the surrounding wetland environment is challenging, however, and is currently under study. Deep brackish groundwater is sometimes referred to as “fossil water.” This water source is vast—there is much more brackish water in the oil sands area than there is bitumen—but once it is removed from the earth it will not recharge. Alberta Environment has several studies under way on groundwater in the oil sands region, including a study to examine the quality and availability of fresh and brackish groundwater in the region ranging from Fort McMurray south to Cold Lake, where a great deal of SAGD development is taking place. The hydrogeology is not consistent across the region, and in some areas brackish water sources are likely to be hydraulically connected to less saline water closer to the surface.

Each individual project that relies on groundwater (either fresh or brackish) performs pumping tests prior to development to determine whether the local water source is adequate to meet the project’s needs. Water availability and appropriate pumping rates are site specific. A lack of a suitable source of groundwater could occur for some leases in any of the three scenarios. However, groundwater use for in-situ production is of particular concern in the Barreling Ahead scenario, where nearly four times more water than is used today will be needed, despite decreasing SORs. Some operators may have to find creative solutions to meet their water needs, perhaps including finding water sources outside their lease. This process could be more difficult when oil sands development is denser and more projects are relying on the same aquifers, as is likely to occur in Barreling Ahead.

### Tailings Accumulation and Management

**Key question: How much waste material does the oil sands mining process create, and how is this waste managed?**

**Why it matters: Waste material and water management are closely related, since a great deal of water is retained in mining waste. Additionally, mining waste must be incorporated into the landscape during site reclamation.**

Oil sands mines produce very large amounts of waste material. An average of two tons of oil sands ore is required to produce a single barrel of bitumen, although this varies with ore quality. Waste material generated is retained on the mine site. Ponds that contain water and solids from oil sands extraction currently cover approximately 140 square kilometers (55 square miles), the size of Staten Island, New York. Managing this waste material properly is essential to limiting the mines’ environmental impact.

Approximately 12 to 14 barrels of water are used to extract a barrel of bitumen from mined oil sand ore.* All of this water and the solids leftover from the extraction process are contained on site in tailings ponds, built above grade using dikes or below grade in mined-out areas. Sand sinks to the bottom of the ponds, while water and some remaining bitumen float to the top. Water from the top of the ponds is recycled back into the oil sands extraction process. The middle layer of the tailings ponds consists of a combination of clay, silt, and water known as fluid fine tailings. Clay and silt removed from the oil sands ore do not entirely separate from the water used in the extraction process. Instead, even after years of settling in the tailings ponds, the mixture only reaches 35 to 40 percent solids and has a consistency similar to pudding or yogurt. In approximately 40 years of commercial oil sands development, the industry has produced nearly 1 billion cubic meters (35 billion cubic feet) of these fluid fine tailings, and the ponds that contain these tailings and other mining waste cover nearly 30 percent of the area currently affected by mining.

Fluid fine tailings are an essential part of water management because they retain so much water, even after years of settling. For every barrel of bitumen produced, approximately four barrels of water are trapped in the resulting fluid fine tailings and settled sand, meaning that this water is currently unavailable for reuse. The water trapped in the tailings is one of the primary determinants of the amount of water that must be removed from the Athabasca River for operations, since this water is not recycled and must be made up from another source. Of the 12 to 14 barrels of water used in the extraction process for each barrel of bitumen produced, 8 to 10 barrels are recycled from the tailings ponds. The four barrels of water that remain trapped in sand and fluid fine tailings must be replaced, primarily with water from the Athabasca River, with the remainder from site runoff and mine dewatering.

Recovering water trapped in fluid fine tailings and allowing fluid fine tailings to become part of a trafficable landscape are the goals of a new ERCB directive. The directive requires that 50 percent of the clay and silt produced from the oil sands ore after July 2012 be removed from tailings ponds and made solid enough to support heavy equipment traffic. Less than half of the clay and silt in the oil sands ore ends up as fluid fine tailings; the remainder is associated with the sand layer at the bottom of the pond. Thus, the directive effectively means that all fluid fine tailings must be treated and made solid after 2012. If the technology works, accumulation of fluid fine tailings will end after this date, and a portion of the water trapped in fluid fine tailings will be available to be recycled into the oil sands extraction process.

Several engineering options are available to solidify tailings, including dewatering using centrifuges; treatment with gypsum, lime, polymers, or carbon dioxide ($CO_2$) (known collectively as consolidated tailings); or air drying. Dewatering tailings with centrifuges and consolidated tailings produce water that can be recycled into the extraction process, but this water is lost to the environment when tailings are air dried. The first commercial application of consolidated tailings is under way and nearing completion at Suncor's Pond 5. At the same time, Suncor's Pond 1 (the Tar Island dike) is being reclaimed using a variety of techniques in a treatment evaluation program expected to be completed in early 2010.

*Gross water use in mined oil sands extraction is 12 to 14 barrels per barrel of bitumen. Net water use is four barrels of water per barrel of bitumen. The difference between these numbers is recycled water.

Success at dewatering tailings is an important part of providing enough water for expansion of oil sands mining operations and reducing the amount of water needed from the Athabasca River. The extra water recovered from tailings helps to reduce the amount of water storage needed, especially in the Barreling Ahead scenario with its high mining growth and water needs. However, the high pace of growth in this scenario may make meeting the goals of the tailings directive challenging. In the New Social Order scenario we consider the possibility that a new directive requires oil sands operators to solidify tailings produced in the past as well, slowly eliminating fluid fine tailings from the landscape and providing more recycled water back to the extraction process. In the Deep Freeze scenario low oil prices reduce the availability of funding for tailings research, and advancement in treatment technology proceeds slowly.

## Tailings Pond Toxicity and Regional Water Quality

**Key question: How toxic are the tailings ponds, and what impact do they have on wildlife and water quality in the region?**

**Why it matters: Any leakage from the tailings ponds is likely to flow into the Athabasca River, toward Lake Athabasca and sensitive ecosystems downstream. Additionally, the tailings ponds are hazardous to waterfowl that land there.**

Water deposited in the tailings ponds has been found to be toxic to aquatic life in assays involving fish and microorganisms, but the toxicity decreases over time. Naphthenic acids removed from bitumen during the extraction process are the primary source of this toxicity. Naphthenic acids tend to dissolve in water during the extraction process, rather than moving with the bitumen or adhering to sediment. Thus, they concentrate in tailings water as it is recycled through the extraction process. Tailings pond water also contains several other organic and inorganic substances that exceed ambient water quality guidelines issued by the Canadian federal government (the Canadian Environmental Quality Guidelines for protection of aquatic life) or the Alberta government (maximum discharge limits from the Environmental Protection and Enhancement Act), including benzene, phenols, toluene, polycyclic aromatic hydrocarbons, ammonia, aluminum, arsenic, copper, cyanide, and iron. Tailings pond water is also saltier than surrounding surface water. These water quality standards are not directly applicable to the oil sands water, because the sensitive aquatic species that these guidelines are designed to protect do not live in the tailings ponds, and the water is not directly released to the environment (except through seepage, as described below). Additionally, the toxicity of the water decreases slowly over time as organic compounds degrade, with some studies showing a much lower level of toxicity after about ten years.

Leaking from the tailings ponds is a matter of concern, particularly since several of the ponds are very close to the Athabasca River. Tailings ponds are generally designed with secondary containment structures to capture water that escapes the pond and send it back. Suncor's Tar Island dike provides an example of secondary containment in a pond built above grade using a dike. The dike was constructed using tailings sand and contains drains to allow water seeping through the sand to be collected and pumped back into the pond. At the end of the dike a ditch also collects runoff water that is pumped back into the pond. Tailings ponds constructed below grade in mined out areas often have wells that intercept shallow groundwater that may contain seepage from the pond and pump the water back into the pond. An additional factor that minimizes seepage from the ponds is the low hydraulic conductivity of the clay in the fluid fine tailings at the bottom of the ponds.

Despite these precautions, the tailings ponds are unlined earthen structures and are not completely contained. Some water seeps through the ponds and into the environment through groundwater. However, measuring the volume of this seepage is difficult, and no public data exists about tailings pond seepage. Alberta Environment has monitored groundwater quality in the region of the oil sands mines for some time, requiring each operator to provide an annual groundwater monitoring report. Additionally, Alberta Environment is studying the water balance in the region to better understand water flows and the extent of pond seepage.

The Regional Aquatics Monitoring Program (RAMP) has been monitoring water quality in the Athabasca River and surrounding lakes since 1997, including measuring water quality parameters, fish populations, and the health of benthic invertebrate communities. The purpose of the program is to monitor the environment in the oil sands area for evidence of change due to industrial activity, and its members include oil sands operators, agencies of the provincial and federal governments, and representatives of Aboriginal groups. The monitoring program has not found significant regional changes in aquatic resources related to oil sands developments or tailings pond seepage. Local changes in water quality have occurred due to permitted activities, including creek diversions and the discharge of treated domestic wastewater.

The RAMP was criticized in a 2004 peer review as inadequate to detect change in the Athabasca River watershed. However, the program has been strengthened since that time, with more monitoring sites added, more consistency in monitoring sites, and improved detection limits for important contaminants, such as naphthenic acids. A second peer review due to be completed in 2010 will shed additional light on the program's effectiveness. Over time, additional data from Alberta Environment and RAMP may provide a better understanding of whether and how humans and wildlife are exposed to tailings pond seepage. At this point, very little is known.

The surface layer of bitumen found on most tailings ponds is an acute threat to wildlife. News reports of more than 1,000 ducks dying on a tailings pond in April 2008 brought this issue to the forefront. The ducks died from being coated with bitumen, not because of any other toxic substance in the ponds. Mine operators employ several mechanisms to deter waterfowl from landing on the tailings ponds, including cannons, scarecrows, and decoy predators. Operators also skim and reclaim bitumen from the surface of the ponds.

### Human Health Impacts of Oil Sands Development

**Key question: What impact does oil sands development have on human health in the immediate area and downstream?**

**Why it matters: Researchers are concerned about patterns of chronic disease in communities downstream of the oil sands region, particularly in Fort Chipewyan.**

Fort Chipewyan is an isolated community located 280 kilometers (174 miles) north of Fort McMurray. The town is located on the shores of Lake Athabasca, near the Peace-Athabasca Delta and adjacent to Wood Buffalo National Park. The population of about 1,200 consists predominantly of Aboriginal people, including Cree, Chipewyan, and Métis.

Several doctors and nurses that serve Fort Chipewyan observed a number of cases of chronic disease in the community, including diabetes, cancers of the blood and liver, autoimmune diseases such as lupus and Graves disease (a disease that causes overactivity of the thyroid gland), and kidney failure and raised concerns about a potential environmental cause. Local residents also describe changes in the health of fish and wildlife that they catch and hunt, including deformities and changed taste and texture of meat. These changes could be due to pollution or due to stress on the wildlife population from other sources, such as changes in the food web. Many residents of Fort Chipewyan rely on fishing, hunting, trapping, and gathering for much of their food, making them particularly vulnerable to environmental contaminants.

Multiple studies have been conducted on the health of Fort Chipewyan residents, but their conclusions have been inconsistent. Alberta Health and Wellness concluded in 2006 that overall cancer rates in Fort Chipewyan were not higher than in the rest of Alberta.* The report did find elevated rates of Graves disease, kidney failure, and blood cancers (despite the finding that overall cancer rates were not elevated). Subsequently, the Alberta Cancer Board released a study in 2009 that came to the opposite conclusion on cancer, stating that cancer rates in Fort Chipewyan are higher than would be expected statistically.** Community leaders in Fort Chipewyan rejected the results of both studies, stating that both used incomplete data and did not adequately engage with community members. The Nunee Health Board, which is responsible for the health of the community on behalf of Health Canada, commissioned another study, completed in 2007.*** This study found arsenic, mercury, and polycyclic aromatic hydrocarbons in water and sediment at levels of concern, and concluded that the concentrations of these contaminants were rising. The study did not focus on a statistical analysis of cases of illness, but instead suggested that a more robust environmental monitoring program is needed to understand the health risks faced by residents of Fort Chipewyan and to better protect this population.

Linking incidences of illness back to an environmental source is a difficult exercise. The small population in Fort Chipewyan adds to the difficulty, since the small sample size makes determining the statistical significance of disease difficult. Additionally, the oil sands are not the only industry that adds to the pollution load in the area. Several pulp mills are operating along the Athabasca and Peace Rivers. Uranium City, Saskatchewan, where many uranium mines operated until 1983, is located across Lake Athabasca from Fort Chipewyan. Additionally, the Athabasca River naturally has oil sands along its banks, adding hydrocarbons to the river. Despite these complicating factors, continuing monitoring of the health of people

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*Alberta Health and Wellness, *Fort Chipewyan Health Data Analysis*, July 2006.
**Alberta Cancer Board, Division of Population Health and Information Surveillance, *Cancer Incidence in Fort Chipewyan, Alberta, 1995–2006*, February 2009.
***Timoney, Kevin P. *A Study of Water and Sediment Quality as Related to Public Health Issues, Fort Chipewyan, Alberta.* Treeline Ecological Research, Sherwood Park Alberta. November 11, 2007.

downstream of oil sands development and of environmental quality indicators is crucial to ensure that oil sands development occurs in a way that protects human health, animal health, and the environment.

## Land Disturbance and Reclamation

**Key question: At what pace will land disturbed by oil sands operations be restored? How will the ecology of reclaimed land differ from its predisturbance state?***

**Why it matters: Canada's boreal forest is ecologically important, and landscape reclamation is important to local residents, particularly Aboriginal groups.**

The natural state of land in the oil sands region is boreal forest. The boreal forest is the largest terrestrial ecosystem on earth, at one time stretching unbroken across the northern latitudes of North America, Europe, and Asia. The global range of boreal forest is larger even than the Amazon rainforest, and Canada has 1.3 billion acres of pristine boreal forest. Evergreen trees dominate the landscape, and 30 to 40 percent of the area is wetlands. The forest is home to many animals, including caribou, bear, wolves, moose, deer, and countless types of birds. Additionally, the boreal forest in Alberta provides recreation for local residents and traditional land use, such as hunting, trapping, and fishing, for Aboriginal groups.

### *Reclamation of Land Disturbed by Mining*

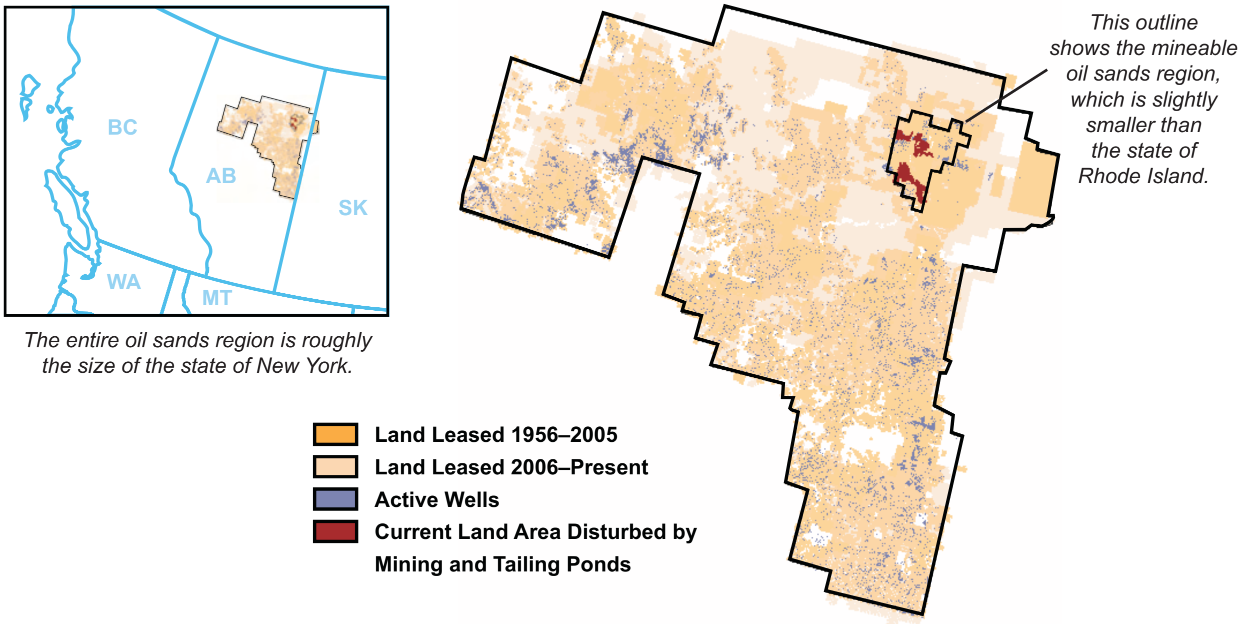
As oil sands production has increased, the amount of land disturbed by mining has grown rapidly (see Figure III-7). Mining operations result in a total loss of the ecological character of the disturbed land. Shell describes the impact this way in the application for its Muskeg River Mine expansion, "Effectively, a complete loss of soil and terrain, terrestrial vegetation, wetlands and forest resources, wildlife and biodiversity happens for this area for the period of operations." This description emphasizes the importance of the reclamation effort. The operators of mining facilities must submit detailed operation and reclamation plans to gain project approval, including baseline studies that capture knowledge on the region before mining begins. The plans describe the expected level of disturbance during operations, measures that will be taken to mitigate impacts, and details of the reclamation plan. For example, to comply with the Federal Fisheries Act, operators must include a plan to ensure no net loss of fish habitat during the operation of the mine and restoration of fish habitat after mining. The newest project approvals have included the creation of temporary lakes to provide fish habitat during mining operations. Despite the level of detail in the planning documents, the definition of "reclaimed" land and the pace of reclamation are open questions for many who want the land restored as closely as possible to its predisturbance state.

Even though oil sands mines have been active for more than 30 years, to date land reclamation has not kept pace with the rate of land disturbance. To some extent, the slow pace of reclamation is a result of the development arc of mining operations. Oil sands mines have long lives, and many years are required to finish mining in an area so that reclamation can begin. For this reason operators have had few opportunities to demonstrate successful

*Disturbed land is land where natural vegetation has been partially or totally cleared, wetlands have been drained, or the land has otherwise been changed from its natural ecological state.

**Figure III-7**

**Land Leased and under Active Development in the Oil Sands Region**




Source: Cambridge Energy Research Associates, IHS, ERCB.
Note: Comparisons to US states are to the total areas of the states, including land and water.
90107-18

## How Much Land Is Changed by Oil Sands Development?

Alberta's entire oil sands region encompasses 55,000 square miles (142,000 square kilometers)—21 percent of Alberta's total area, or the size of the state of New York (see Figure III-7).

Approximately 200 square miles (518 square kilometers) are currently disturbed by surface mining, equivalent to 0.1 percent of Alberta's total area, 2 percent of greater Houston, 4 percent of greater Calgary, or an area large enough to contain four of the five boroughs (Manhattan, the Bronx, Brooklyn, and Staten Island) of New York City.

Of that disturbed land, tailings ponds cover 55 square miles (140 square kilometers), nearly 30 percent of the mining-disturbed area, roughly the size of Staten Island.

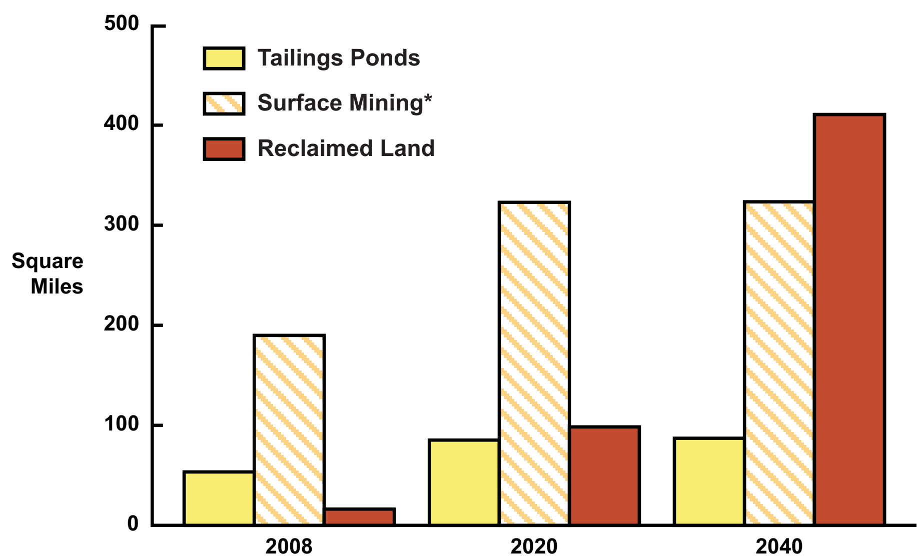
reclamation. Today about 8 percent of the land disturbed by surface mining is considered reclaimed, although only a very small parcel of land (about 1 square kilometer, or 0.4 square miles) has been certified as reclaimed by the Alberta government and released back to the public. Certifying the land requires allowing public access, and certifying more reclaimed land is not feasible today because it is located within the bounds of active mining operations.

According to approved reclamation plans for surface mines, the amount of reclaimed land will have increased sixfold by 2020 from its present level but will still be only one third the size of disturbed land (see Figure III-8). Between 2020 and 2040 the land area reclaimed increases significantly, while the area disturbed remains the same size. To date the pace of land reclamation, while slow, has been in line with expectations set forth in the projects' approved reclamation plans. However, the pace of tailings reclamation has not met the goals outlined in the original approvals. The tailings issue highlights that the approved reclamation plans are not binding, although the recent ERCB tailings directive will reduce the future rate of tailings accumulation.

Finding a balanced approach to land reclamation is a challenge. When an area is disturbed on the scale and extent of oil sands mining, the land is irreversibly changed. To what extent the reclaimed land will resemble its predevelopment state and whether the same plant and animal populations will return are still open questions. Prior to development, much of the mined area consisted of wetlands—bogs, fens, and swamps. Although collaborative research involving industry, academia, and local Aboriginal groups is under way to increase knowledge

**Figure III-8**

**Oil Sands Mining Footprint and Reclamation Process**




Source: Cambridge Energy Research Associates.
Data source: ERCB, reclaimed land data from Environmental Impact Assessments for new projects and 2006 reclamation plans for existing operations.
*Indludes tailing ponds.
90107-12

on restoring biodiversity in land reclamation, the science of restoring wetlands is in its infancy. Successful restoration of peaty wetlands (bogs and fens) is a particular challenge and has not been successfully demonstrated to date. Reclaimed land is likely to consist of a combination of highland forest and wetlands.

So-called end-pit lakes (EPLs) are a controversial part of mining reclamation plans. EPLs are engineered bodies of water built in mined-out areas, and at least 25 of them are included in the reclamation plans of existing and planned mines.* These EPLs are intended to contain fluid fine tailings and other mining waste at the bottom, topped by a layer of fresh water, and to become a permanent part of the landscape after reclamation. Ideally, the depth and shape of these lakes would prevent the water in contact with mining waste from mixing with clean water closer to the surface. However, no EPLs have been constructed to date, and the potential for these bodies of water to become active ecosystems that support plant and animal life is unknown.

The recently passed tailings directive should reduce the amount of fluid fine tailings produced and thus the number and size of EPLs needed to dispose of these tailings, bringing mine operators into compliance with their original reclamation plans. No technology has yet been proven to incorporate fluid fine tailings into a reclaimed landscape. Reclamation is likely to include a suite of technologies, including both dry tailings and fluid fine tailings stored in EPLs.

### *Reclamation of Land Disturbed by In-situ Production*

Instead of completely clearing the land, in-situ development consists of clearing parts of the boreal forest to site facilities required to produce bitumen. CERA estimates that the disturbed area of a SAGD project averages about 6 to 7 percent of the lease. This compares favorably to mining, but the land disturbance is larger than for conventional oil production, which disturbs about 4 percent of leased land, or natural gas, at about 2 percent.** Although SAGD uses horizontal drilling methods that drill as many as ten well pairs from a central pad, for the projects analyzed the land disturbance of SAGD projects is larger than for conventional oil or gas. Several reasons account for the difference.

- The size of the facility needed to generate steam and treat water is larger than a conventional oil battery or gas compressor station.
- Pipes for steam and bitumen in SAGD run aboveground, creating larger cleared paths than the underground pipelines used in conventional oil and gas production.
- SAGD sites in remote locations generally include support buildings and camps to house workers.

*Not all of these mines will be built in all scenarios, so the number of EPLs actually built could be smaller.
**CERA estimated the extent of disturbed land using aerial photographs and project approval maps for selected sites: SAGD at Devon Jackfish, conventional oil from the Fletcher Leduc-Woodbend, and conventional gas from EnCana Strathmore.

About 18 percent of the total area of Alberta is leased for in-situ development. Because of the significant size and the pristine, undeveloped state of much of the land in the leased area, stakeholders are concerned about the cumulative impacts of potential projects. Fragmentation of the forest caused by in-situ oil sands production is believed to decrease the populations of some animal species, such as lynx, wolves, and caribou, which tend to leave an area when human development occurs. However, the extent of the disturbance is difficult to quantify since data on many species populations in remote regions are difficult to gather. The Alberta Biodiversity Monitoring Institute recently concluded a study on the status of birds and vascular plants in the Lower Athabasca region.* The study found that 7 percent of the land in the area had been altered by human activity (including agriculture and forestry in addition to energy development), and the biodiversity of the region for birds and vascular plants had declined 6 percent. The study did not measure the impact on mammals, but it is an important step in establishing biodiversity data for the region.

Reclamation requirements for in-situ sites are typically outlined in each projects' Environmental Impact Assessment (EIA).** The EIA outlines information regarding the baseline conditions on the lease prior to development, details regarding the salvage of materials such as soil and timber and plans for restoring the topography after development. These reclamation goals will be much easier to reach compared to mining reclamation because of the much smaller scale of degradation. Much of the leased land remains boreal forest during site operations.

### What Will the Future Bring?

Reclamation is a major focus of the New Social Order scenario. EPLs are eliminated because legacy tailings are treated to become trafficable surfaces. Research advances in the science of wetlands restoration and strong pressure from the Alberta government and Aboriginal groups keeps reclamation moving forward. On the other hand in the Barreling Ahead scenario the pace of reclamation is unlikely to keep up with the rapid pace of production growth and land disturbance. Reclamation is also likely to be slow in the Deep Freeze scenario, but for different reasons. The low oil price environment leaves little extra cash for reclamation activities, although fewer projects are developed in this scenario and thus less land is disturbed.

## TECHNOLOGY ISSUES

Continuing technology development is a critical issue in reducing costs and decreasing the environmental footprint of development. Research is under way, and new technologies are on the horizon that could help the oil sands meet the cost and environmental performance requirements of future energy markets.

*Alberta Biodiversity Monitoring Institute, *The Status of Birds and Vascular Plants in Alberta's Lower Athabasca Planning Region 2009 Preliminary Assessment, February 2009.*

**Projects that produce less than 12,600 barrels per day are not required to produce an EIA and must follow the Alberta government's *Guide to Reclamation for Well Sites and Associated Facilities for Forested Lands in the Green Area.*

## Opportunities to Reduce GHG Emissions

**Key question: How much can oil sands operators decrease their GHG emissions, and at what cost?**

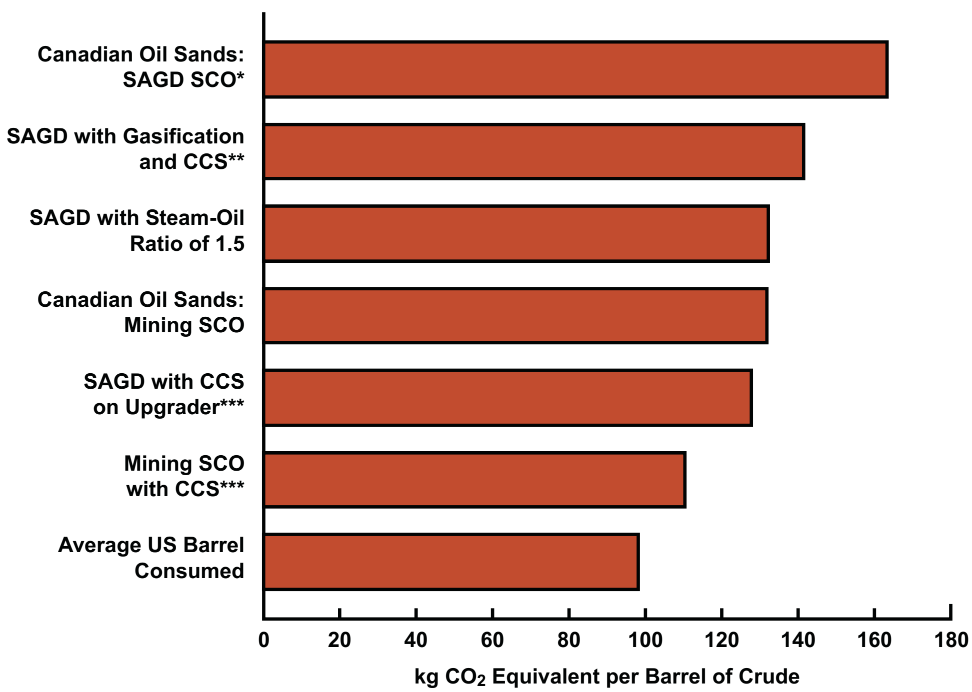
**Why it matters: Strong climate change policies could substantially add to the cost of oil sands' GHG emissions or require that these emissions be reduced.**

Canadian oil sands have greater life-cycle GHG emissions than the average crude oil consumed in the United States. Future emissions policies could put new pressure on oil sands operations to reduce their GHG emissions. Improved efficiency and carbon capture and storage (CCS) are two options that could reduce GHG emissions associated with oil sands production.

In the near term, improving the efficiency of oil sands production presents the most cost-effective and technologically feasible opportunity for reducing emissions for both mining and SAGD (see Figure III-9). For example with mining operations, improved process reliability to

**Figure III-9**

**Well-to–retail pump Greenhouse Gas Emissions: Opportunities to Reduce Emissions from Canadian Oil Sands**




Source: Cambridge Energy Research Associates.
*Assumes a steam-oil ratio of 3.
**Assumes that the upgrader is powered by gasifying petroleum coke instead of natural gas. Additional syngas produced from the upgrader is used in SAGD to produce the needed steam for crude production, displacing SAGD natural gas consumption.
***CCS on SMR unit in the upgrader. No other GHG emissions are captured.
90107-13_2404

maximize upgrader throughput can help to lower energy consumption per unit of processed fuel and thus lower life-cycle emissions. Opportunities also exist in SAGD operations to reduce GHG emissions; for example, improving the SOR of SAGD production from today's average of 3 to 1.5 would reduce well-to–retail pump GHG emissions by about 20 percent. Achieving an SOR of 1.5 would require new technology, such as the use of solvents, but this ratio could reduce emissions by over 1 million metric tons per year for a 100,000 barrel per day (bd) SAGD operation. Even with an SOR of 1.5, a SAGD operation would have greater life-cycle GHG emissions than the average crude consumed in the United States but would produce fewer emissions than the average crude produced today in Nigeria or Angola. Completely new extraction technologies, as described in the next section, have the potential to further increase the efficiency of in-situ oil sands production. However, these technologies are not yet viable.

CCS could also reduce the life-cycle emissions from oil sands production, but it will likely be at least a decade before CCS is commercially viable at the scale needed for the oil sands. Two CCS technologies that can be implemented at a practical scale are in the bitumen upgrading portion of the value chain.* The first option involves capturing a relatively pure stream of $CO_2$ from a steam methane reforming (SMR) unit used for hydrogen production. This form of CCS could reduce the emissions associated with upgrading by about 40 percent and the total well-to–retail pump emissions of synthetic crude oil by about 20 percent. Another CCS option involves capturing the $CO_2$ emissions from a bitumen upgrader that uses petroleum coke gasification instead of natural gas to produce the facility's energy. In this case well-to–retail pump emissions would decrease by about 15 percent compared with today's typical SAGD operation.**

Implementing CCS increases capital and operating costs substantially. Retrofitting an SMR unit for CCS can cost between $500 and $700 million for a 100,000 bd upgrading facility, and equipping a gasification plant for CCS is likely to exceed $1 billion, in addition to the $1.5–$2 billion cost of building the gasification plant. Translating these capital costs into dollars per ton of GHG abatement costs suggests that $CO_2$ prices (or taxes) would need to exceed $50 per metric ton of $CO_2$ for an SMR retrofit and nearly $100 per metric ton of $CO_2$ for CCS on a gasification plant in order to economically justify the additional expenses. Some studies find even greater carbon capture costs—in excess of $150 per ton. The technology is embryonic and cost estimates are based on early engineering estimates that vary widely. No matter which cost estimate one uses, for wide-scale adoption of CCS to be economic, CCS costs would need to decline significantly or $CO_2$ allowance prices (or taxes) would need to significantly exceed $50 per ton.

*There are other CCS options, such as using amine scrubbers to capture GHG emissions from SAGD boilers, but current cost estimates suggest this technology is further from implementation than the two options discussed here.

**In both examples CERA assumes that parasitic load from the CCS equipment increases energy use by about 30 percent, thus decreasing the impact of $CO_2$ capture. For the SMR retrofit example CERA assumes that 40 percent of the emissions associated with the upgrading portion of the value chain are captured. For the gasification example CERA assumes that 60 percent of emissions associated with both upgrading and steam creation are captured. Finally, in the case of the gasification unit, petroleum coke simply has much higher $CO_2$ emissions as a feedstock fuel compared with natural gas.

For successful commercialization of CCS, policies that go beyond putting a price on $CO_2$ emissions will be required to address $CO_2$ transportation (i.e., pipeline development), storage site licensing, storage liabilities, and monitoring requirements. Assuming that these barriers can be overcome, the geological storage opportunities in the Fort McMurray area appear to be limited, suggesting that a $CO_2$ pipeline connecting the Fort McMurray area to regions farther south will be needed.* The costs of such a pipeline combined with the need for collaboration among many operators to build the pipeline would further increase the barrier for CCS in oil sands.

CCS and improved efficiency present opportunities for reducing GHG emissions along the oil value chain, but their adoption will not necessarily lower the total emissions associated with oil sands production. For example, under a scenario where oil sands production continues to rise, the combined effects of CCS and improved efficiency would be unlikely to overcome the GHG emissions increase associated with increased production. In all three CERA scenarios oil sands production and GHG emissions continue to rise, but with the high carbon prices in the New Social Order scenario substantial reductions in GHG emissions per barrel occur even as aggregate emissions levels increase.

CCS and energy efficiency for oil sands must be considered in a wider context. More than 70 percent of GHG emissions associated with oil consumption occur during combustion of the final refined product. This portion of the value chain is largely outside the purview of oil and gas companies and lies instead with automobile manufacturers, consumers, and regulators through vehicle fuel efficiency. Furthermore, policies targeting economywide emissions are likely to encourage emissions reductions in many other sectors of the economy, many of which are likely to be less expensive to implement than reductions in the oil sands.

## Improvements in Oil Sands Technology

**Key question: How could oil sands production technology improve in the future?**

**Why it matters: Technology improvements for both SAGD and mining could bring reductions in cost, GHG emissions, and water use, along with other environmental benefits.**

Since the inception of the first commercial oil sands facility in 1967, the industry has made major technological strides in optimizing resources, reducing costs, increasing efficiency, and reducing its environmental impact. Innovation—led by industry, academia, and government—has reduced the extraction and processing costs of oil sands as well as reduced their environmental footprint, particularly in oil sands mining. The changing of mining equipment from drag lines and conveyors to shovels and trucks, the transport of oil sands ore in a water slurry (known as hydrotransport), and the reduction in the extraction temperature of the ore have all greatly reduced the energy intensity of oil sands mining. Although mining is relatively mature compared to in-situ production techniques, new technologies to manage fluid fine tailings will reduce water use and make reclamation easier.

*Geologists working in the region suggest that geological formations in central Alberta are more amenable to $CO_2$ storage than those near Fort McMurray.

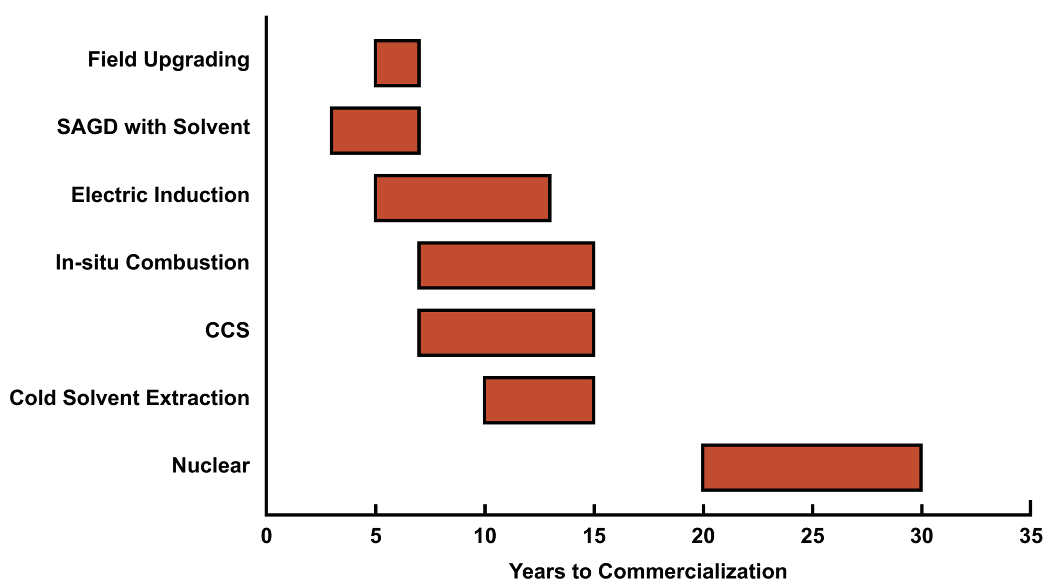
The development of SAGD technology was a major step forward in in-situ production technology. Incremental improvements in SAGD have already improved recovery and reduced costs and GHG emissions. Best-in-class SORs have already fallen from around 6, seven to eight years ago, to as low as 2.2 today, reducing energy use and GHG emissions. Optimizing the use of solvents (propane or butane) in SAGD processes could result in further reductions in the SOR, perhaps as low as 1.5. Reduction in SOR reduces the operating costs, natural gas demand, GHG emissions, land footprint, and water use of SAGD projects.

Future drilling practices will be less intrusive on the landscape as more wells are drilled on the same well pad and distances attained by horizontal drilling continue to increase. Continuous improvement will result from ongoing optimization of reservoir management, infill drilling, and improved steam distribution techniques. Better control of sand could result in higher operational efficiencies, leading to improved recoveries of bitumen. Downhole pumps already boost recoveries.

In addition to incremental improvements to existing SAGD technology, several technologies that are in various stages of development today have the potential for more radical changes in oil sands production. All of these, however, will have to be proven effective and economic at scale. Figure III-10 depicts an estimate of the availability timeline for a range of oil sands technologies.

**Figure III-10**

**Current Estimated Timeline for Innovative Oil Sands Technologies**




Source: Cambridge Energy Research Associates.
90107-30

- **Gasification technology** allows solid fuel (such as petroleum coke or asphaltenes) to be converted into a gaseous fuel that can power a turbine (applications: upgrading and in-situ).

- **Consolidated tailings and tailings dewatering and drying** allow fluid fine tailings to be converted to a surface solid enough to handle heavy equipment traffic (application: mining).

- **Pure solvent extraction techniques**, either hot or cold, could result in total replacement of steam, greatly reducing GHG emissions and water use and markedly increasing oil recovery. Cost implications would depend on solvent cost and availability, as well as achieving high solvent recycle rates (application: in-situ).

- **Field upgrading** uses small-scale units to "crack" a portion of the bitumen, producing some lighter petroleum products and a by-product fuel that can be used on site instead of natural gas to raise steam. Field upgrading reduces the viscosity of bitumen enough to allow it to be transported through pipelines without adding diluent. The lack of diluent and natural gas inputs could result in substantial operating cost savings when intergraded with an in-situ operation (application: in-situ).

- **In-situ combustion techniques** (often described as fire-flood processes) involve underground combustion of some bitumen, warming the reservoir enough to allow the remaining bitumen to flow. The process has the potential for lower capital costs, lower operating costs, less water use, and lower GHG emissions. Additionally, the bitumen is partially upgraded underground as the heavier fractions burn, and some variations of the technology incorporate a catalyst with the goal of further upgrading bitumen in the reservoir (application: in-situ).

- **Electric induction technologies** involve introducing electric energy into the oil sands through an inductor and an alternating magnetic field generated around the inductor. This process heats the bitumen and produces higher recoveries when combined with steam injection. The benefits could include lower water consumption and energy use (similar to an SOR of 0.5 to 1 for SAGD), higher yields, lower GHG emissions, and flexibility to recover bitumen from reservoirs that are not ideal for current in-situ technologies (application: in-situ).

- **Nuclear power** could be used to produce steam and electric power in SAGD operations, but significant progress would be required in the development of small modular nuclear units. Small modular nuclear reactors that produce 30–100 megawatts-electric are currently under early development but are as yet unproven (application: in-situ).

New Social Order, with its high carbon price and focus on clean energy, brings about the most innovation in oil sands technology. Technological changes focus on reducing environmental impacts and GHG emissions, and include CCS, solvent extraction, in-situ combustion techniques, and small nuclear facilities. Technological changes in the Barreling Ahead scenario primarily come about to replace natural gas because of rising prices. These technologies include gasification for upgraders, using asphaltenes or petroleum coke as fuel, and technologies that do not require steam, such as solvent extraction and in-situ combustion techniques. Technological change in the Deep Freeze scenario focuses on lowering operating costs to survive in the low oil price environment. Technologies that take hold in this scenario include solvent extraction and incremental improvements to the SAGD process.

## Government Investment Is Key to Improving Oil Sands Technology

**Key question: How to pay to develop and improve oil sands technology?**

**Why it matters: Growth in oil sands production and improvement of environmental performance depend on technological advancement. Individual companies do not always have the resources or incentive to do the basic research required.**

The federal and provincial governments led early research and investment in the oil sands. Carl Clark of the Alberta Research Council developed the hot water extraction process—the answer to unlocking the bitumen from the sand. Entrepreneurs established the first processing plants in the 1920s and later in 1940s, but the federal and the provincial governments stepped in to purchase these early plants when they became unprofitable. Even in more recent times, when the Syncrude project struggled with financing in 1973, the governments of Canada, Alberta, and Ontario became investors.

Government continues to play a vital role in oil sands innovation, but industry contributions to new technology have become more important over time. Development of in-situ technology was a true collaborative effort among industry, academia, and government. Roger Butler developed the idea for SAGD at the University of Calgary in the early 1980s, but it took collaboration between government and industry through the Oil Sands Technology and Research Authority (AOSTRA) to prove that Dr. Butler's idea could be commercially viable. Government-funded research today is conducted at the Alberta Energy Research Institute (AERI, formally AOSTRA); at CANMET, a federal research laboratory; and at universities in Alberta and beyond. However, as the oil sands have become a commercial enterprise, the mix of funding has changed. In the early days the government spent the majority of money, whereas today, the government spends about half as much as it did 15 years ago and industry contributes a much larger share. Moreover, today a strong bubbling of innovation comes from small entrepreneurs in addition to the large oil companies that continue to research new technology. New technology is also advanced through industry consortiums. For example, the Integrated $CO_2$ Network and the Alberta Saline Aquifer Project are two industry groups studying CCS.

Increasing oil sands production and decreasing the environmental impact of this production depends on a number of technological advances. Many potential advances will require the kind of basic research that individual companies do not have the resources or incentive to conduct. For example, researching CCS technology and providing the necessary infrastructure for $CO_2$ transport is too large an undertaking for any one company. Continuing government involvement in basic oil sands research will likely be critical to achieving the technological advances the industry needs. A key requirement for addressing the oil sands' environmental challenges is sustained government support for research and development across a broad range of technologies, not just CCS. The challenges and needs and the potential societal benefits fit the classic formula for government-supported research and development.*

*See the report *Energy R&D: Shaping Our Nation's Future in a Competitive World* by the US Secretary of Energy Advisory Board Task Force on Strategic Energy Research and Development, US Department of Energy, Washington DC, 1995.

# CHAPTER IV: CERA'S OIL SANDS SCENARIOS

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## WHY SCENARIOS?

> A long run view of history reminds us of the presence of changes, ruptures, and discontinuities. It should warn us against simply extrapolating from a brief period of a few years, and projecting the future as simply a continuation of the immediately lived and experienced past.
>
> —Professor Harold James, Princeton University, author of *The End of Globalization: Lessons from the Great Depression*

What are scenarios and why use them? Unlike forecasting, the scenario process does not attempt to foretell the one "right" future, but instead expands analysis to gain a broader and more systematic understanding of how several possible and plausible futures could unfold and the key forces shaping them. Forecasting exercises begin with factors that are assumed to be certain and extrapolates from them. Because of this, forecasts can unwittingly disguise uncertainties and conceal risks. They also often assume a greater predictability about the future than is in fact the case. Scenarios, by contrast, acknowledge uncertainties as a principal "building block" in determining the factors that could lead to a future that is different from the present. Scenarios encourage people to disengage from position, prestige, point of view, and established interests to think about the future in a more flexible way.

The scenario process is well suited to considering the future of the oil sands. Many factors shaping the future of the oil sands are uncertain and could plausibly unfold in several ways. There are also issues on which a wide range of views exists. Scenarios inject more perspective into the discussion about the future than a single line forecast. Scenarios illustrate worlds that *could* happen—not necessarily worlds that *should* happen.

The oil sands scenarios presented in this report draw from the three scenarios originally prepared for CERA's 2006 Multiclient Study *Dawn of a New Age*: *Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030*. The *Dawn of a New Age* scenarios outlined three very different worlds. One considered the impact of rising Asian economies on the world energy system. A second explored the repercussions of oil prices' attaining levels of $150 per barrel. A third imagined a severe global recession triggered by a financial crisis. In the three short years since those scenarios were completed, important elements of each of these very different worlds have become a reality for the world energy system. The rapidly changing and unpredictable nature of this short period of history underscores the necessity for stakeholders to think about the future in a broader way and to resist the inevitable human tendency toward simple extrapolation.

*Growth in the Canadian Oil Sands: Finding the New Balance* uses CERA's global scenarios as a starting point and backdrop, while drilling down into issues specific to the Alberta oil sands. This study presents three different outcomes for how the oil sands could be developed (see Table IV-1). These scenarios are intended to explore the potential boundaries for the development of the oil sands, taking into account the issues and uncertainties we have identified. They are by no means the only possible paths of development that could be

### Table IV-1

### Key Storylines of CERA's Long-term Oil Sands Scenarios

**NEW SOCIAL ORDER.** A global oil supply crisis leads to several years of oil prices above $100 per barrel. Alternative fuels and vehicles emerge and North American oil demand declines sharply. The emphasis of Canadian and US governments shifts decisively toward environmental regulation (especially carbon) and encouragement of green energy technologies.

**BARRELING AHEAD.** North American and world oil demand exhibit healthy growth on the back of a robust economic climate. World oil prices remain consistently strong. The Canadian government's emphasis is on maximizing oil sands development, including diversifying export markets and facilitating a more moderate cost environment. Efforts to regulate GHG emissions follow a "middle-of-the-road" path.

**DEEP FREEZE.** Global economic growth stagnates, and protectionism and antiglobalization sentiment dominate the political-economic landscape. Oil demand and oil prices remain depressed. There is little urgency or political appetite to implement GHG regulations.

Source: Cambridge Energy Research Associates.

envisioned. Indeed, it is possible that like CERA's global energy scenarios, the future will ultimately contain elements of all three scenarios. For this reason CERA does not assign probability to any scenario, but rather encourages stakeholders and business leaders to use these scenarios to think as broadly as possible about how they might adapt to a world that does unfold in expected ways—and a world of surprise and rapid, discontinuous change (see Table IV-2).

## NEW SOCIAL ORDER SCENARIO: KEY INSIGHTS

**Insight 1.** A period of high prices may appear beneficial to the oil sands, but it sows the seeds of demand destruction and encourages more government support for alternative forms of energy. This could, in the long term, result in downward pressure on oil prices and higher costs for producing oil sands.

**Insight 2.** Long-term petroleum demand growth in North America is not assured, even with population and economic growth. Efficiency gains, consumer behavior changes, and inroads by alternative fuels could ultimately lead to a peaking of demand. This could result in stranded investments in the oil sands if productive capacity is not carefully calibrated with demand growth.

**Table IV-2**

**Snapshot of Key Variables in CERA's Oil Sands Scenarios**

| | Barreling Ahead | New Social Order | Deep Freeze |
|---|---|---|---|
| |  |  |  |
| Gross Domestic Product (GDP) Global Average Growth, 2009–35 (constant 2008 US dollars) | 4.20% | 3.80% | 2.90% |
| North American Petroleum Demand Growth, 2009–35 | 1.6 million barrels per day (mbd) (+8%) | -1.8 mbd (-9%) | +0.5 mbd (+3%) |
| North American Biofuels Demand Level, 2035 | 1.7 mbd | 2.7 mbd | 1.2 mbd |
| Global Liquids Demand Growth, 2009–35 (includes biofuels) | +29 mbd (+35%) | +16.5 mbd (+19%) | +14 mbd (+17%) |
| West Texas Intermediate (WTI) Average, 2009–35 (constant 2008 US dollars per barrel) | $64 | $77 | $27 |
| Henry Hub Average Price, 2009–35 (constant 2008 US dollars per million British thermal unit [MMBtu]) | $10 | $10.30 (net of carbon price) | $5 |
| Average Capital Cost, Integrated Mine and Upgrader Alberta, 2009–35 (constant 2008 Canadian dollars per flowing barrel) | C$105,000 | C$174,000 | C$95,000 |
| Downstream Product Split (2035) | 61% Synthetic crude oil (SCO); 39% Bitumen | 58% SCO; 42% Bitumen | 45% SCO; 55% Bitumen |
| Upstream Product Split (2035) | 51% Mine; 49% In situ | 51% Mine; 49% In situ | 43% Mine; 57% In situ |
| Oil Sands as a Share of US Total Crude Imports | 37% | 24% | 23% |
| Oil Sands Production Capacity (2035) | 6.3 mbd | 3.0 mbd | 2.3 mbd |

Source: Cambridge Energy Research Associates.

**Insight 3.** The tension between the need for energy security and the desire for cleaner energy sources is unlikely to be completely resolved. By virtue of their size, the oil sands remain critical to total North American oil supply. Their importance will be magnified during disruptions of conventional oil supplies in the greater world oil market.

**Insight 4.** A regulatory framework focused on sustainable development and a price on carbon dioxide ($CO_2$) emissions could spur technological innovations that enable the oil sands to become a cleaner source of energy. This shift could be concurrent with a less frenetic pace of development, particularly when compared to the Barreling Ahead scenario.

**Insight 5.** Carbon capture and storage (CCS) is an option for reducing greenhouse gas (GHG) emissions from oil sands. However, capturing $CO_2$ is expensive, and geological constraints in the Fort McMurray area prevent $CO_2$ captured from oil sands operations from being stored locally. Industry collaboration will be required to build the pipeline network required to ship the industry's aggregated $CO_2$ volumes for sequestration in central Alberta.

**Insight 6.** Improvement in the management of tailings ponds, mining waste, and land reclamation—which accelerates in this scenario—is crucial for public acceptance and regulatory compliance of oil sands growth, since they are the most visible symbol of the oil sands' environmental cost.

**Insight 7.** The oil sands could benefit economically and environmentally from the deployment of gasification and CCS. However, these technologies are not commercial on a large scale today. To achieve commercial success, these technologies will require significant technological innovation, a steep decline in capital costs, and a high cost of carbon.

## THE CLEAN ENERGY REVOLUTION: THE ECONOMIC AND ENERGY CONTEXT OF NEW SOCIAL ORDER

Energy use today is dominated by fossil fuels. Despite expectations that the world will shift away to newer, cleaner forms of energy—such as renewables in power generation and transportation—such a change has only been incremental up to this point. But what if governments attempted to remake their economies on a platform of clean energy? What if a paradigm change in energy production did occur? What might be the plausible events that set such a course of events in motion, and what impact would they have on the Canadian oil sands industry?

The New Social Order scenario is the most revolutionary of the three scenarios. It supposes a massive shift in the global economic system, in which leading industrial nations transform their economies from a model in which economic benefits are maximized and free markets reign to a model that emphasizes a greater degree of government direction of the economy, especially regarding sustainable development and the internalization of the social and environmental costs of fossil fuels. The Canadian oil sands are at the nexus of this shift.

The scenario does not assume that governments can engineer such a monumental change simply by fiat. Rather, it assumes that a broad societal shift occurs as a result of both the global economic crisis that began in 2008 as well as a new, more severe oil crisis in 2014 in which the vulnerability of the global economy to disruptions in oil supply is revealed as never before. There is a major societal rethink of the role of government in the economy in general and energy specifically. Alternative energy is pursued aggressively.

The New Social Order scenario has mixed implications for the Canadian oil sands. The high oil prices associated with the oil crisis provide the economic opportunity for the industry to invest and grow and meet a market need for secure supply. Early in the scenario, oil sands are viewed as an attractive investment opportunity for international oil companies that see dwindling opportunities around the world to invest and replace their reserves. At the same time, however, a regulatory shift is occurring in which much more emphasis is placed on environmental protection and sustainable development. Tightening regulations raise the cost of developing the oil sands. Perhaps more importantly, demand for petroleum enters a permanent decline in North America, as a revolution in alternative fuels, electric vehicles, and efficiency gains takes hold. In this scenario the oil sands industry has two well-defined periods: strong growth initially, followed by virtual stagnation as demand falls, oil prices decline, and environmental regulations tighten significantly.

Although oil sands production flattens out in the second half of this scenario, there are still quantifiable economic benefits that accrue to Canada and the United States. Total direct and nondirect spending related to oil sands developments grows to over C$40 billion (constant 2008 Canadian dollars) per year. By 2035 about 450,000 jobs are directly or indirectly related to the oil sands, the majority of which are long-term operations positions. New construction jobs are sustained by the move within the industry to advanced technologies for steam generation and CCS projects. Total municipal, provincial, and federal government revenues in the past ten years of New Social Order average C$8 billion (constant 2008 Canadian dollars) per year.*

### The Next Oil Crisis

The economic crisis of 2008–09 is deep, but a recovery emerges in 2010 thanks to the injection of huge amounts of liquidity by national governments around the world. Nevertheless, as soon as the first crisis passes, a second one emerges, driven by yet another cyclical—and even more violent—upswing in energy prices.

As energy demand recovers from the economic crisis, it becomes evident that supply growth is insufficient to keep pace. Too many oil production projects were delayed, deferred, or shut in during the crash in oil prices that occurred in 2008–09. Oil prices begin a strong recovery, and by 2011 the benchmark light, sweet crude averages about $100 per barrel in constant 2008 US dollars ($109 in nominal terms).

Despite a rapid return to a high oil price environment in 2010, the producers' supply response initially lags. Raising the capital necessary for new projects is difficult, owing to still-sluggish credit markets. In the equity markets primary and institutional investors are hesitant to funnel capital toward the oil sands, as they are fearful that the latest run-up in oil prices will reverse as quickly as in 2008. The appetite for new oil sands investment is further limited by the emergence of alternative fuels and vehicles and increasingly aggressive government mandates intended to decrease oil demand.

*CERA estimated these economic benefits by leveraging methodology outlined in the Canadian Energy Research Institute (CERI) 2005 study *Economic Impacts of Alberta's Oil Sands.*

After oil prices remain high for several years, however, the market for investment funds begins to open up. By 2014 incremental annual capacity growth is over 100,000 barrels per day (bd). From this point production growth returns to high gear, stretching Alberta's ability to supply the required materials and labor for the multiple projects running in parallel.

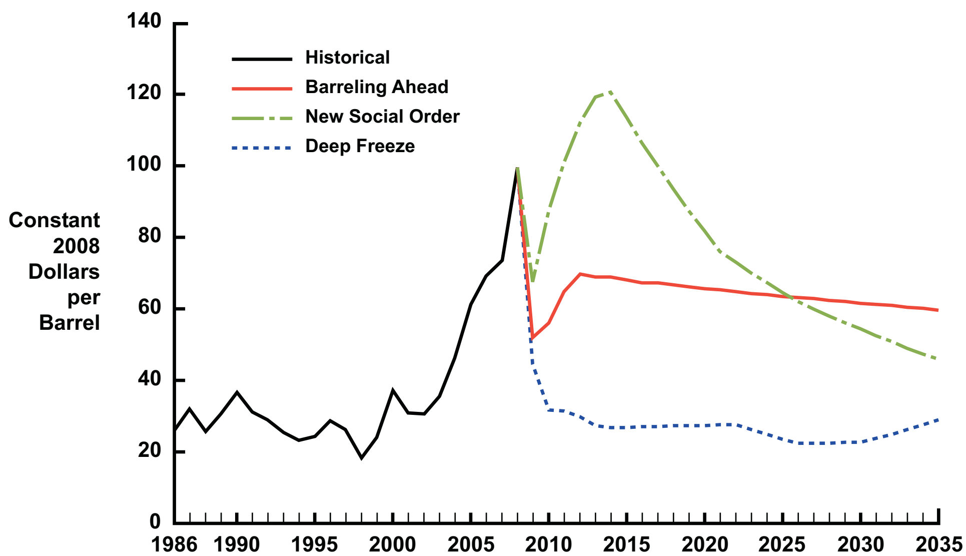
In 2014 a series of severe supply disruptions, including lengthy disruptions in West Africa and the Middle East, push oil prices even higher. The net result is that global spare oil production capacity tumbles to razor thin levels. Oil prices reach absolute levels last seen in 2008, but this time the crisis is broader and longer lasting. Prices recede only gradually over the course of several years. Benchmark light, sweet crude prices average $121 per barrel in constant 2008 US dollars ($140 per barrel in nominal terms) and do not drop below $100 in constant 2008 US dollars until nearly 2020 (see Figure IV-1).

## A New Social Order Is Born

This period of continuous turmoil in the oil markets, coming on the heels of the economic crisis of 2008 and 2009, has a profound impact on government activism around the world. In both Canada and the United States citizens encourage the government to reinvent their economies on a clean energy platform. The Canadian federal government's Clean Energy Program (CEP) is initiated in 2013. The CEP reallocates some of the oil wealth from western Canada to investments in an ambitious array of zero-carbon energy technologies, such as hydroelectricity, renewable power technologies, and nuclear power. These government programs also provide strong incentives for alternative fuels and technologies in the transport sector, including biofuels and plug-in hybrid electric vehicles.

**Figure IV-1**

**WTI Real Crude Oil Price**




Source: Cambridge Energy Research Associates, Platts.
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The Canadian federal government also establishes a new industrial strategy focused on an internationally competitive infrastructure for the production and export of green technologies. Similarly, clean energy industries become a critical component of the US economy, which is seeking to remake itself out of the financial catastrophe of 2008–09. A new social order is born.

Society's growing consideration of social and environmental issues results in increasing regulatory oversight for the oil sands industry, particularly in addressing the cumulative impacts on air quality, water quality, and land use created by oil sands development. Phase II of the Athabasca River Water Use Framework brings in a new era of radical changes in water management for the Athabasca River, including eliminating most withdrawals in the winter. Mine operators respond by storing more water on their leases. Tailings management regulations are expanded to require dewatering of tailings from past operations, and the recovered water from tailings reduces net water use and withdrawals from the Athabasca River. Reclamation of mining lands accelerates, and the inclusion of wetlands in the reclaimed landscape is mandated. In response technology for wetlands restoration improves, including progress in restoring fen bogs and peat-forming wetlands toward the end of the scenario period. All these changes result in rising costs for oil sands producers.

Aboriginal groups resort to legal recourse on conflicts between oil sands developments and their traditional uses of land as well as the maintenance of defined areas of wetlands. The government responds by setting aside 30 percent of the land in the Regional Municipality of Wood Buffalo to remain undeveloped. To preserve some lands, the Alberta government takes advantage of leases that are due to expire and in other cases forces operators to trade leased tracts for other lands.

### A Climate Change Policy with Teeth

As part of their mandates to remake the economic and energy landscape, both the Canadian and US governments institute stringent regulations that require deep cuts in GHG emissions. Of the three scenarios the climate change policies adopted in New Social Order are the most aggressive.

The United States and Canada carefully negotiate a host of policies aimed at reducing GHG emissions in New Social Order. The centerpiece of these policies is an economywide cap-and-trade program—a market-based policy whereby the government sets an overall limit on the amount GHG allowed to be emitted and then private companies or individuals trade for the right to emit the pollutant. These allowances are fungible between Canadian and US market participants. The program is implemented on an aggressive timeline and starts in 2012. The new law targets a 30 percent reduction in US and Canadian GHG emissions by 2030 from 2008 levels. Allowance prices under this new carbon regime are robust and climb to $100 per metric ton in constant 2008 terms ($134 in nominal terms) by 2020.

Critically the price of carbon in this scenario is high enough to support the commercial deployment of CCS—a technology that matures as learning and scale drive its costs lower. CCS is retrofitted to existing oil sands operations, and a host of other carbon reduction opportunities become commercial after 2030 under the new carbon pricing regime—including new "small" nuclear power plants and most renewable power options. And, in contrast to the other scenarios, this cap-and-trade program applies along the entire fossil fuel value chain, from the wellhead to the tailpipe. The most important effect from the point of view of the Canadian oil sands is that this program contributes to the beginnings of the decarbonization of the transportation sector, accelerating the decrease in petroleum demand.

An important aspect of this scenario is that CCS cannot occur without substantial industry collaboration. The geological formations around the Fort McMurray region do not support carbon sequestration, and therefore the industry's $CO_2$ emissions must be piped to the Edmonton area for storage. Individually, each oil sands operator cannot justify the high capital cost of a pipeline, since their emission volumes are not large enough. Therefore, in 2020 the industry and government collaborate to fund the construction of a network of gathering pipelines to aggregate $CO_2$ and transport them via a central pipeline to Edmonton.

A federal low-carbon fuel standard (LCFS) is also passed into law by the US government in New Social Order. This LCFS requires oil companies to reduce the GHG emissions intensity (as measured on a full life-cycle basis) of transportation fuels supplied to the market by 10 percent. Essentially, compliance can be achieved through improving the life-cycle carbon-intensity of crudes (through production efficiency gains or technology like CCS), by processing lower carbon-intensive crude oils (assuming they are available), and by increasing the blending of biofuels that have a demonstrable life-cycle reduction in GHG emissions.

Partially in response to the LCFS, Canadian oil sands producers improve the GHG intensity of producing and upgrading bitumen to SCO by one third by 2035. Primarily this is accomplished through improved efficiency and the limited adoption of CCS technology. However, the downstream oil industry complies with the LCFS primarily by blending increasing volumes of biofuels—especially imported sugar cane–based ethanol and next-generation biofuels derived from cellulosic material, both of which have low life-cycle GHG emissions. By 2020 these advanced cellulosic-based biofuels are becoming commercially available owing to technology advances, the regulatory push from the LCFS, and other government incentives. By 2035 the North American vehicle fleet increasingly comprises flex-fuel cars and light trucks, able to run on any combination of gasoline, conventional ethanol, or advanced bio-gasoline (for example, biomass-derived higher alcohols such as butanol). By 2035 biofuels make up over 20 percent (by volume) of gasoline consumption and nearly 10 percent of diesel consumption in North America. Plug-in hybrids make up nearly 25 percent of all new light duty vehicle sales by 2035.

Despite the ramp-up in biofuel blending and improved GHG intensity of oil sands production, many oil companies are unable to fully comply with the LCFS, since conventional corn starch–based ethanol, which has a less favorable life-cycle emissions profile than advanced biofuels, retains a significant share of total biofuels supply. A fuel surcharge is imposed on oil companies that are in noncompliance—most of which gets passed on to end consumers.

Both the cap-and-trade program and the LCFS lead to gasoline and diesel prices that are higher than they otherwise would be in this scenario. This is another important reason—in addition to increased fuel economy standards, biofuel blending, and plug-in electric vehicle commercialization—that North American petroleum demand declines in this scenario.

## OIL SANDS DEVELOPMENT: A RAPID RISE AND THEN A SHIFT TO SUSTAINABILITY

For the Canadian oil sands the resumption of high oil prices beginning in 2010 is a green light to resume projects that were delayed during the downturn of 2008 and 2009. For several years commercial and government interest in facilitating rapid growth in the oil sands is strong given chronic supply disruptions in the greater global oil market and the worsening oil crisis.

Over the course of the New Social Order scenario, however, the oil sands face a roller coaster of shifting oil prices and rising industry costs and a sea change in oil demand trends. Ultimately, after a rapid ascent, production capacity stalls at 2.9 mbd by 2020. The most important trends in this scenario are

- **A resumption of cost inflation.** The rapid restart of oil sands investment is quickly accompanied by a resumption of shortages of labor, engineering services, and equipment.
- **The “peaking” of North American petroleum demand.** Changing consumer behavior in the face of higher fuel prices, a scaled-up alternative fuels industry, and the “electrification” of the vehicle fleet all bring about an eventual retreat in oil demand in this scenario. Global oil demand rises, led by developing economies, although significant penetration of biofuels and electric vehicles slows this arc.
- **Another steady retreat in oil prices.** The prolonged period of high oil prices in the early part of the scenario proves unsustainable in the face of weak demand for petroleum. Benchmark light, sweet crude oil prices decline steadily during the last ten years of the scenario, averaging $55 per barrel in constant 2008 US dollars ($94 in nominal terms).
- **Higher environmental and regulatory costs.** The Albertan and Canadian governments develop a wide-ranging strategy to develop the oil sands in a (more) sustainable manner. Further regulations covering land, air, water, and boreal forest issues are imposed, which significantly raise the cost of doing business in the oil sands.
- **Technology becomes the great enabler.** Declining demand and rising cost pressures are especially problematic for the oil sands as the world’s marginal producers. In response oil sands technology advances rapidly in this scenario to maintain the sector’s viability.

### Investment Resumes, but Costs Rise

Over 1 mbd of new oil sands capacity comes online from 2010 to 2020. High oil prices and increasingly available financing encourage investment, allowing production capacity growth to ramp up from 2014 to 2020. By 2020 full-cycle steam-assisted gravity drainage (SAGD) economics require a WTI price of over $60 per barrel (constant 2008 US dollars) to cover a 10 percent return on investment, and integrated projects with a bitumen upgrader require a price over $100 per barrel.

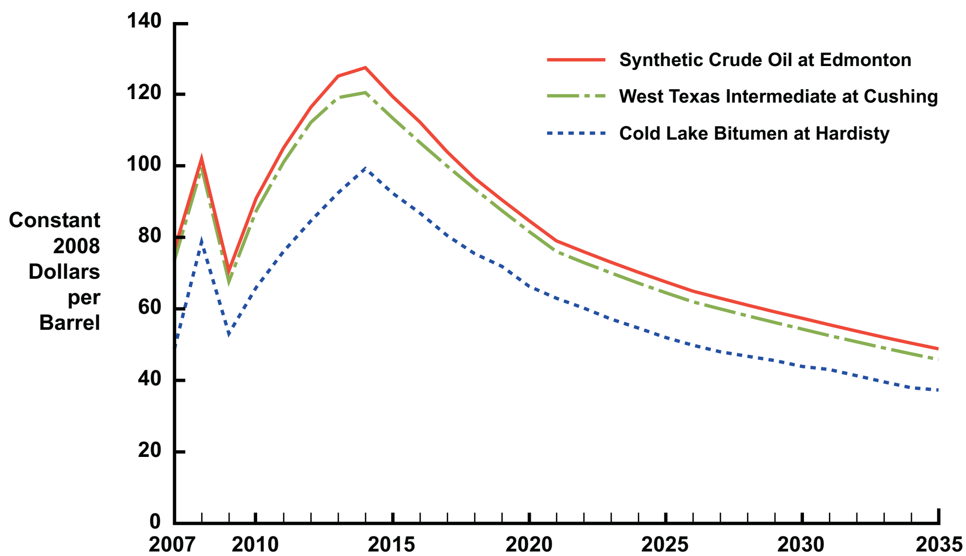
As the oil crisis escalates and benchmark light, sweet crude prices remain at elevated levels, SCO prices far outpace bitumen prices. Light, sweet crude oil prices are at a substantial premium during this period, owing to the supply disruptions of high-quality crude oils from West Africa and elsewhere in the world (see Figure IV-2).

This healthy price differential between bitumen and light crudes, which averages about 20 percent during this scenario, motivates investment in upgraders. Ultimately, between 2010 and 2020 a total of about 650,000 bd of SCO capacity comes online. There is strong demand for this product, as it yields mostly transportation fuels, which are in short supply owing to the disruption in conventional light, sweet crude imports into North America during the oil crises of the first half of this scenario. The US Midwest and Rocky Mountain states—the traditional market outlet for oil sands material—increase their imports of both SCO and diluted bitumen during this period, facilitated by the completion of new pipeline capacity in the early part of the decade. Demand for diluted bitumen from 2010 to 2020 in these two important markets increases from 380,000 bd to 880,000 bd.

With oil sands production rising rapidly, however, and refiners throughout North America eager to access this growing and politically stable source of oil, new pipelines are needed. In 2018 Line 9—a 200,000 bd pipeline that currently flows from Montreal to Sarnia—is reversed to allow shipment of SCO and synbit (a 50/50 blend of SCO and bitumen) to Quebec

**Figure IV-2**

**New Social Order Scenario: Oil Prices**




Source: Cambridge Energy Research Associates.
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refiners. In 2014 a 500,000 bd pipeline is completed, linking Alberta producers to the US Gulf Coast. The sophisticated refining hub of the US Gulf Coast proves a deep market for incremental bitumen supplies, allowing Canadian producers to fetch world prices for their products. A second pipeline is added by 2020 to accommodate the increasing volumes of oil sands products, which are needed to replace volumes in the US Gulf Coast as Venezuelan and Mexican oil production declines. In this scenario a new export pipeline to the West Coast does not materialize owing to the Canadian government's focus on sustainability and environmentalism. Shortages of diluent, which is required to ship bitumen by pipeline, are initially an impediment for the industry in this scenario. But with the completion of a pipeline from Chicago to Edmonton, producers are able to access both recycled diluent and diluent supplies all the way from Mont Belvieu, Texas.

Expansion of oil sands production capacity from 2014 to 2020 also brings an unwelcome resumption of industry cost increases. Capital costs initially drop by 10 percent from their peak in 2008 until 2010 as a result of the slowdown caused by the great recession of 2008–09. However, the slowdown in Alberta and other oil-producing regions around the world is short lived, and with benchmark light, sweet oil prices averaging close to $90 per barrel by 2015, capital costs start once again to increase as investment surges and producers begin executing projects in parallel. With growing levels of project activity in Alberta and high oil prices supporting a new surge in energy investment globally, the supply chain for materials and equipment becomes stretched. Capital costs for oil sands projects return to the steep escalation profile of the 2004 to 2008 period. Alberta's ability to supply labor is also tested, as demand exceeds labor supply by the end of 2014 and reaches 33,000 workers by 2017.

By 2020 the capital cost to build an upgrader or a SAGD facility in the Fort McMurray area is over 30 percent higher than the previous peak prices in 2008. New integrated SAGD projects with a bitumen upgrader require a WTI price over $100 per barrel to meet a 10 percent return hurdle rate—much higher than prevailing light, sweet crude prices. By the end of 2020 this capital cost escalation combined with the downward trend of oil prices renders many of the oil sands projects uneconomic. Bitumen-only projects remain economic, but producers concerned with the upward trajectory in costs and the downward trend in oil prices put new investment decisions on hold. Existing projects are completed, but new investment ceases. Despite low project activity and declining energy prices during 2025 to 2035, the global move to alternative fuels and technologies (such as gasification and carbon capture) keeps pressures on many global suppliers of equipment and engineering, preventing oil sands capital costs from falling significantly. In contrast to the Barreling Ahead scenario, industry finds less sympathy from the federal government regarding these stubborn cost pressures, since the government's mandate in this scenario is firmly to promote clean energy and sustainability, and many of the factors maintaining pressure on costs are global, not local, in nature.

Although new projects from 2025 to the end of the scenario period are not economic, existing oil sands operations are able to easily cover their operating costs. Integrated oil sands operating costs average $30 per barrel and SAGD operating costs average $21 per barrel. Carbon allowance prices, which average over $100 dollars per metric ton (constant 2008 dollars) by 2020, make up about $6 per barrel of operating costs for SAGD.

Finally, the Alberta "sliding scale" royalty regime remains unchanged in this scenario. By 2020, with integrated investments no longer economic, there is little the government can do with royalty relief to bridge the growing economic gap. Instead the government remains focused on leveraging hydrocarbon revenues to invest in alternative energy projects as part of its sustainable energy strategy.

## Peak Demand in North America

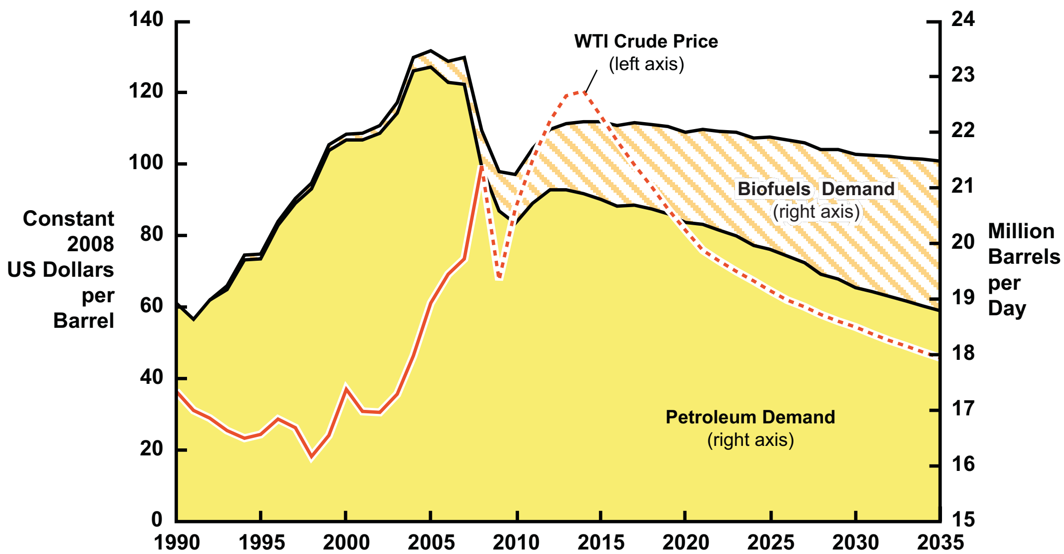
From 1986 to 2007 North American petroleum demand grew by 5.3 mbd. Growth in this market—especially for transportation fuels—was a central and dependable feature of the greater world oil market. In the New Social Order scenario the days of growth are gone. Instead North American petroleum demand enters a long, slow decline.

Peak demand occurs partly as a result of aggressive government initiatives to kick-start a scaled-up biofuels and electric vehicle industry, and partly owing to changes in consumer behavior in response to the extended period of elevated oil prices. The North American cap-and-trade regulations add about $1 per gallon (constant 2008 US dollars) to end-user gasoline prices by 2020, which keeps fuel prices high even as world crude prices begin falling.

Vehicle fleet efficiency improves substantially during 2010–20 after two decades of stagnation. Biofuel consumption increases dramatically, growing from 850,000 bd in 2010 to 2.7 mbd in 2035, owing to breakthroughs in second generation fuels made from cellulosic material and other technological advances (see Figure IV-3). Plug-in electric vehicles attain 25

**Figure IV-3**

**New Social Order Scenario: North American Liquid Fuel Demand and WTI Crude Price Oil Path**




Source: US Energy Information Administration, Platts, Cambridge Energy Research Associates
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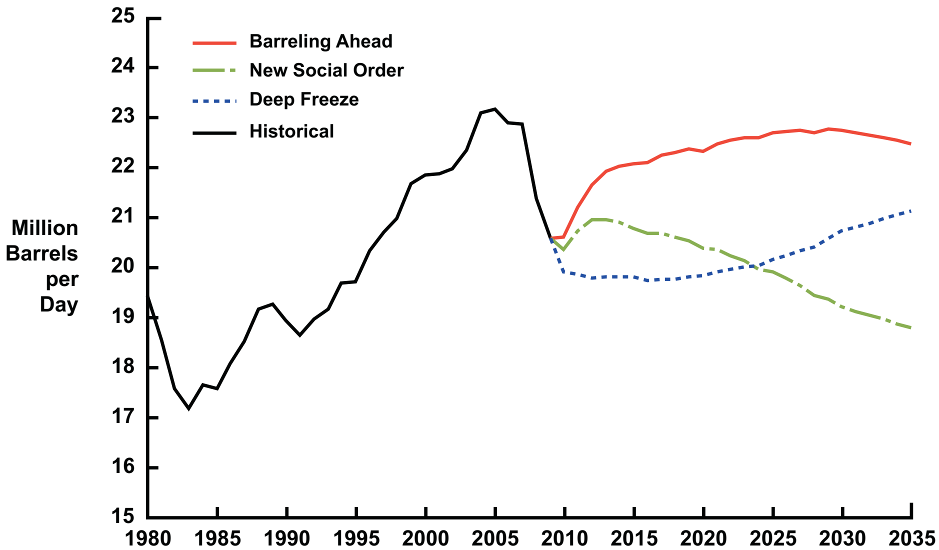
**Figure IV-4**

**North American Petroleum Demand by Scenario**




Source: Cambridge Energy Research Associates, and International Energy Agency.
Note: History and projections exclude biofuels.
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percent of new vehicle sales by 2035, further depressing demand for petroleum-based fuels. By 2020 this evaporation in petroleum demand has become a steady trend and is another signal to oil sands producers that investment needs to slow drastically. Ultimately, North American petroleum-based fuels demand declines 1.8 mbd from 2009 to 2035 (see Figure IV-4). Refineries therefore gradually decrease their capacity (and their demand for crude) to prevent overcapacity. This is especially true in the US Midwest, where demand is especially weak and new biofuels supplies are increasingly available.

World petroleum demand grows in the New Social Order scenario, although the growth is concentrated entirely in developing countries. Total liquids demand grows by 16.5 mbd from 2009 to 2035, although owing to the strong penetration of biofuels, demand for petroleum increases by only 12 mbd, or just 600,000 bd per year.

## What Goes Up Must Come Down: Oil Market Cyclicality

By 2020 the oil crisis that lasted for much of the decade is a receding memory. Oil supply from the Middle East and West Africa has recovered. At the same time, however, North American demand is in terminal decline, as is demand in many other OECD countries. The result is a steady fall in oil prices. For oil sands producers the combination of a bearish market for oil prices and a stubbornly inflationary cost environment leads to a very challenging period.

## Technology: The Great Enabler?

A key feature of the New Social Order scenario is the rapid development of technology. Technology not only enables the scale-up of alternatives to petroleum such as biofuels and electric vehicles, it also enables the oil sands to reduce its environmental footprint. Technology development in the oil sands sector is driven by two factors: the need to reduce the costs of extracting and upgrading the bitumen resource and the need for a smaller environmental footprint. But this transition is not cheap, fast, or easy. And while the oil sands improve their environmental position owing to this contribution of new technology, bitumen and SCO still have greater GHG footprints compared with many other crude oils. The same technology that ameliorates the environmental footprint of the oil sands is also at the same time improving the footprint of other crude oils and fossil fuel energy sources such as coal.

In New Social Order new, cleaner extractive technologies become commercial. SAGD techniques in combination with light hydrocarbon solvents, which are more energy efficient and use far less water, are developed. In-situ combustion technology is also developed, reducing the need for steam and allowing a high proportion of the $CO_2$ to remain sequestered in the formation. Even small nuclear facilities are being used by 2035 to provide steam for SAGD facilities. By 2035 approximately 10 percent of the oil sands total capacity is powered by gasifiers, nuclear generators, or nonsteam technologies, such as in-situ combustion techniques. And by 2035 nearly a quarter of upgraders have been retrofitted with advanced, low-cost gasifiers, all using CCS technology to capture $CO_2$.

As a result of vastly improved steam-oil ratios (SORs), CCS, and other advanced technologies, the GHG intensity of oil sands production improves by over 30 percent between 2008 and 2035 in New Social Order. Although this improvement in emissions intensity is impressive, aggregate emissions from the sector still increase, owing to the significant increase in oil sands production which overwhelms the per-barrel improvements in GHG intensity. By 2035 GHG emissions in New Social Order increase to 65 million metric tons (mt), from about 40 mt in 2008.

In the mining projects technology leads to major advances in tailings and water management. Regulations require industry to develop an effective reclamation process to convert fluid fine tailings, including legacy tailings produced by past operations, to use for trafficable areas. As companies work to comply with these new regulations, they implement a variety of technologies. Existing tailings are consolidated via the addition of gypsum and other substances. Significant progress in the commercialization of centrifuging technologies allows new and old tailings to be consolidated efficiently and cost-effectively. Since old tailings are remediated in this scenario, end pit lakes (EPLs) are ultimately not required in the reclaimed landscape. These advances reduce the volume of water needed to produce a barrel of bitumen from 4 barrels of water to less than 3 barrels. By 2020 large tracts of tailings are trafficable, the volume of tailings ponds necessary to contain waste decreases drastically, and the pace of reclamation accelerates. This, in turn, reaps large benefits in public opinion of the oil sands, since tailing ponds are the most visible evidence of the oil sand’s environmental cost.

## BARRELING AHEAD SCENARIO: KEY INSIGHTS

**Insight 1.** Aggressive expansion of oil sands production could play a major role in boosting world oil supply and strengthening North American oil security, especially in a scenario of rapid oil demand growth worldwide. However, such an expansion would also require substantial increased use of natural gas, resulting in higher gas prices and increasing imports of liquefied natural gas to the United States unless a new pipeline comes into service delivering gas from Alaska to the US lower-48 states. In the absence of gas deliveries from Alaska, the United States would become more reliant on non-Canadian gas imports, since the oil sands would consume a large part of Canadian gas supply.

**Insight 2.** The Canadian oil sands could become a significant source of long-term job and revenue growth for the Canadian economy. Economic benefits could also accrue outside of Canada, as pipeline and refinery retrofits would be needed in the United States to process oil sands material.

**Insight 3.** A substantial increase in Canadian GHG emissions by 2035 is an unavoidable by-product of an aggressive growth path for oil sands unless there is a dramatic improvement in technology. However, it is unclear whether GHG emissions would be substantially different in the absence of oil sands development, since the majority of the liquid fuel needed to meet demand would need to come from another source of crude. The GHG impact of this substitution would depend entirely on the future quality of the liquid fuel replacing the oil sands, which is uncertain.

**Insight 4.** The oil sands could consume a huge proportion of Canadian natural gas production. In the Barreling Ahead scenario oil sands production reaches 6.3 mbd in 2035—up from 1.3 mbd in 2008. To produce this volume, oil sands facilities, in aggregate, consume 6.3 billion cubic feet (Bcf) per day of gas—40 percent of total 2035 Canadian gas demand.

**Insight 5.** Progress in addressing the cumulative effects of land disturbance, water management, tailings accumulation, and other environmental issues could be very challenging to manage in a scenario of the most rapid oil sands development.

**Insight 6.** To reach 6.3 mbd of production in Barreling Ahead, technology or water management practices must advance to minimize consumption of fresh water from the Athabasca River. A key uncertainty is whether groundwater resources could support a large ramp-up in in-situ thermal production capacity.

**Insight 7.** Strong and steady growth in the oil sands is possible only if innovations in cost control and project execution are introduced, such as the offshore fabrication and importation of large equipment modules, which could decrease both cost and regional labor requirements.

**Insight 8.** Favorable government policy could play a critical role in an aggressive expansion of oil sands production, including proactive support to access new markets, to decrease logistical barriers to execute projects, and to gain the support of First Nations groups.

**Insight 9.** Rapid growth in the oil sands will require access to world markets and world prices. Pipeline capacity expansion to the sophisticated refineries at the US Gulf Coast will be required to support such growth, and waterborne access to Asia and the US West Coast is likely to be needed as well.

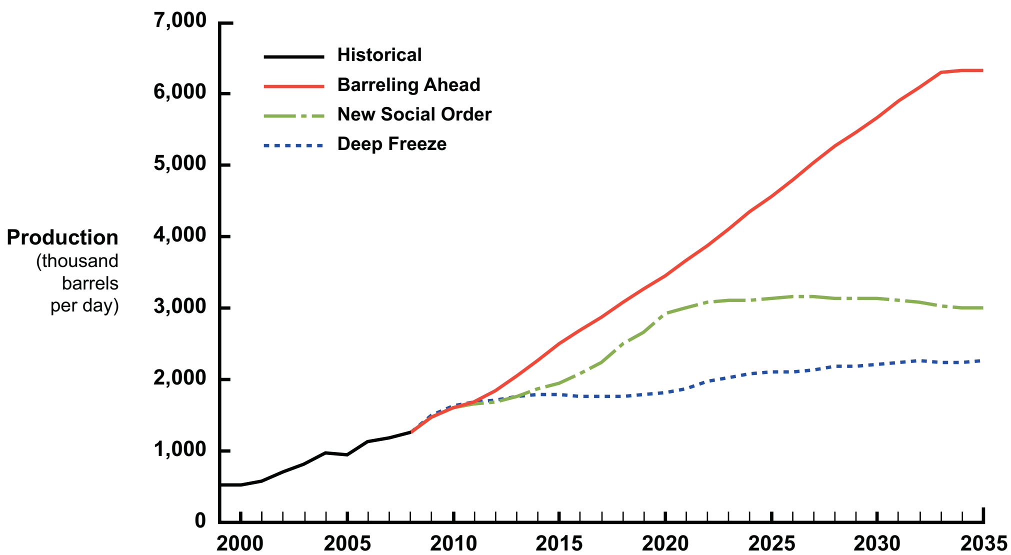
## HOW FAST, HOW BIG—AND AT WHAT COST? THE ECONOMIC AND ENERGY CONTEXT OF BARRELING AHEAD

How fast could the production of Canadian oil sands grow? What would it take to make Canada one of the biggest producers of petroleum in the world? What would be the environmental and social costs and benefits of such aggressive expansion?

These are the questions the Barreling Ahead scenario seeks to answer. In this scenario the Canadian government plays a strong role to facilitate and maximize the development of Canada's vast energy storehouse. Oil sands production reaches 6.3 mbd in 2035 (61 percent SCO and 39 percent bitumen by 2035)—a 400 percent increase from 2008 (see Figure IV-5). Total Canadian crude production tops 7 mbd in 2035, placing Canada among the world's top oil producers. But this scenario also features a substantial increase in GHG emissions from oil sands facilities. Oil sands GHG emissions rise from 40 mt in 2008 to nearly 170 mt in 2035 (see Figure IV-6). Management of water and mine waste are two other key environmental issues associated with oil sands development that are particularly challenging in this scenario. Rapid oil sands development also creates the potential for conflict with Canada's Aboriginal population.

**Figure IV-5**

**Oil Sands Production**




Source: Cambridge Energy Research Associates.
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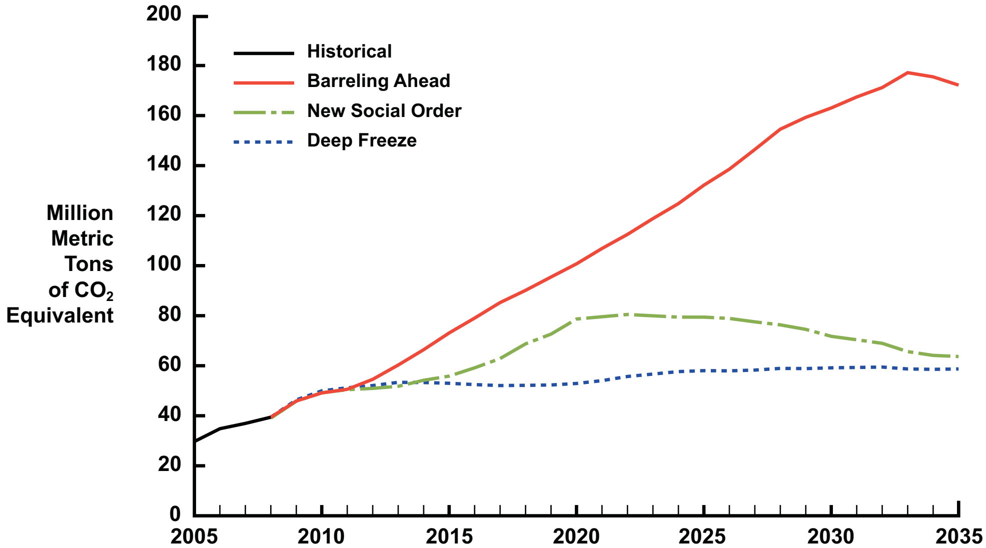
**Figure IV-6**

**Greenhouse Gas Emissions from Canadian Oil Sands Production**




Source: Cambridge Energy Research Associates.
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Strong oil demand—especially in Asia—and high prices are the defining global characteristics of Barreling Ahead. Oil prices remain high enough to support continuous oil sands investment in both integrated and upstream only projects. This scenario also demands much of new technologies, both to facilitate oil sands growth and to mitigate its environmental footprint.

## Economic Recovery and the Resumption of Growth

The starting point for Barreling Ahead—as with all the scenarios—is the "great recession" that began in the United States in 2007 and spread throughout the world in 2008 and 2009. The economic contraction is painful and deep, but mercifully shorter than many expect. The "great recovery" begins in 2010. China, whose economy avoids the steep contraction seen in the United States, is a major engine of the recovery. Another factor that spawns recovery is the impact of trillions of dollars of government spending worldwide, which provides the necessary catalyst to reverse the contraction in global gross domestic product (GDP). In addition to China, other Asian economies, such India and Vietnam, resume a very strong path of economic expansion. India's service industry finds a large new client base in the expanding multinational companies based in China. Of the three scenarios, Barreling Ahead assumes the strongest economic growth during 2010–35, both at the global level and in North America. Global GDP growth averages 4.2 percent per year from 2010 to 2035, while North American GDP growth averages 2.5 percent.

The oil sands themselves are an important contributor to economic growth in North America in the Barreling Ahead scenario. Total direct and indirect spending related to oil sands development grows to over C$90 billion (constant 2008 Canadian dollars) per year. Over 750,000 jobs are created, directly and indirectly, as a result of oil sands development, of which 80 percent are long-term operations jobs. By the last ten years of the scenario Canadian government revenue (municipal, provincial, and federal) grows to C$18 billion per year (constant 2008 Canadian dollars)—nearly four times 2008 levels.*

## The First Prerequisite for Oil Sands Recovery: A Rebound in Oil Demand and Oil Prices

Economic recovery from the great recession of 2008–09 is the first step in the resurgence of commodity prices from the multiyear lows reached in 2009. Oil prices in particular prove resilient, especially as world oil demand returns with a vengeance after the two-year contraction of 2008–09. The benchmark light, sweet crude oil price moves to $56 per barrel in constant 2008 US dollars ($59 in nominal terms) in 2010, drifting up to $68 per barrel in constant 2008 US dollars ($81 in nominal terms) by 2015 before flattening out for much of the rest of the scenario period. In this scenario a relatively tight supply-demand balance for oil reemerges, although prices are at more moderate levels than during the peak in 2008. In other words, in Barreling Ahead oil prices settle into a new equilibrium level that is structurally much higher than pre-2000 levels.

Despite a return to prosperity, the world remains vulnerable to shocks—from trade disputes, security concerns, regional conflicts, and changing geopolitics. As a result, energy security remains high on the agenda of great powers in this scenario—especially in the United States and China, the world's two biggest oil importers. Periodic conflicts and a tight oil supply-demand balance lead energy consuming nations to focus on supply security and diversification. In this context Canada is an attractive and stable environment in which to procure long-term oil supplies—not only for the United States but also for other oil-hungry countries outside of North America.

## The Rise of Asia and the Emergence of a Multipolar World

Indeed, the economic crisis of 2008–09 and the resulting sharp drop in oil demand in the United States highlight for Canada the risk of a highly dependent trade relationship with its huge southern neighbor. Concern about long-term demand for oil in the United States fosters debate about the need to diversify markets as the oil sands develop.

In the Barreling Ahead scenario Canada takes advantage of the emerging multipolar world in which Asia increasingly exerts influence in world economic and political affairs. Canada pushes hard to expand trade with India and China. These energy-hungry nations in turn see the Canadian oil sands as a means of obtaining secure energy supplies and diversifying energy sources and seek active participation as producers. Canada sees major advantages in market diversification, especially given the large volumes of oil sands production in this scenario.

*CERA estimated these economic benefits by leveraging methodology outlined in the CERI 2005 study *Economic Impacts of Alberta's Oil Sands.*

## THE PATH TO 6.3 MILLION BARRELS PER DAY: NEW MARKETS, NEW TECHNOLOGIES, AND NEW ECONOMIC PARADIGMS

By 2035 Canada's oil sands are producing 6.3 mbd of bitumen and SCO—a nearly fivefold increase in production from today's levels. Growth is sustained at a strong and steady pace and averages 180,000 bd of new capacity each year though to 2035.

What are the economic and technological trends that enable industry to achieve this robust level of production? There are several keys to such a growth path:

- **Robust oil prices.** Benchmark light, sweet crude prices average $64 per barrel in constant 2008 US dollars ($91 in nominal terms) during 2009–35 in this scenario, providing an adequate return on investment for both bitumen producers and upgraders.

- **Healthy oil demand.** World oil demand recovers, first in Asia and then in North America. Relatively strong growth is sustained on the back of consistently strong economic growth. World liquids demand increases nearly 30 mbd from 2009 to 2035, propelled by average world GDP growth of 4.2 percent per year.

- **Moderating project costs.** Industry costs decline sharply from the 2008 peak, and subsequent cost increases are incremental; no major, long-lived cost spikes occur.

- **Technological solutions.** Necessity is the mother of invention in this scenario. Key technological breakthroughs keep a growing industry's costs in line. This allows the industry to reduce the intensity of natural gas use per barrel of output, although the magnitude of the overall increase in capacity leads to substantially higher consumption of natural gas.

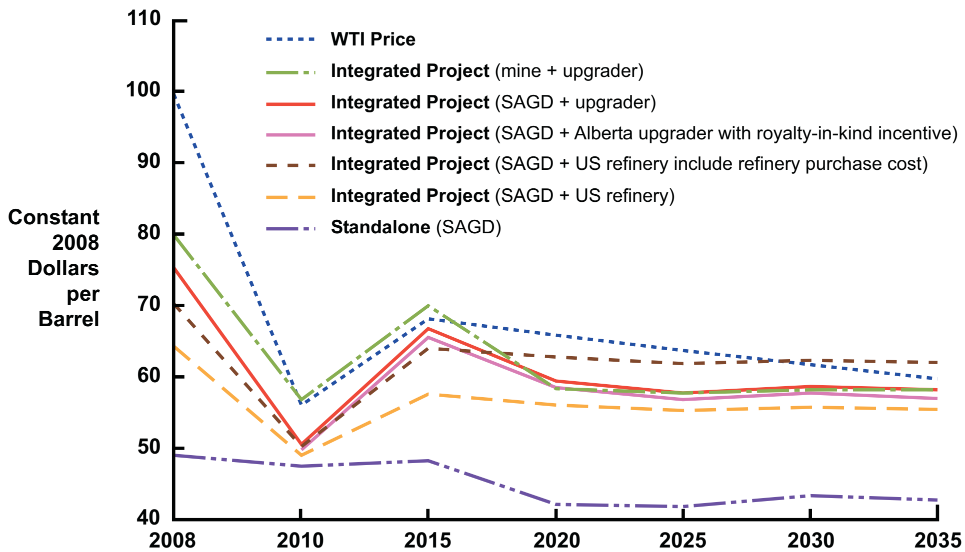
### Improved Project Economics and Stronger Demand

Over the course of the Barreling Ahead scenario in-situ SAGD projects require a WTI price ranging from $40 per barrel to $50 per barrel in constant 2008 US dollars to cover a full-cycle production cost including a 10 percent return on investment. These projects are supported by relatively high prevailing prices for light, sweet crudes in this scenario. Integrated projects with a bitumen upgrader require a WTI price ranging from $50 to $75 per barrel.

Light-heavy crude price differentials gradually narrow throughout the scenario. While Alberta upgrading economics are marginal only for a few relatively short periods during the scenario, the narrower differentials provide a higher return to bitumen producers (see Figure IV-7). Despite these favorable economics for bitumen producers, the bitumen-only strategy is not without risk. Bitumen producers still must ensure that they have an end market for their product, which is not fungible in most refineries. Therefore, bitumen producers continue to seek partnerships with existing refineries in the United States capable of processing bitumen, or purchase refineries which they retool to process bitumen.

**Figure IV-7**

**Barreling Ahead Scenario: Breakeven WTI Prices**




Source: Cambridge Energy Research Associates.
90107-20_1404

The Alberta government is concerned by the potential loss of value-added upgrading to the Alberta economy caused by a reliance on bitumen production instead of upgrading. In 2013 the government begins to roll out its bitumen-royalty-in-kind program (BRIK), which requires producers to pay royalties in physical barrels of bitumen instead of cash. This in turn allows the government to deliver its BRIK barrels to negotiated projects (such as upgraders) and to sell its noncommitted volumes into other markets. To help foster upgrading in Alberta, the government sells BRIK barrels to Alberta-based upgraders at US$2 per barrel below the market price of bitumen, effectively widening the light-heavy price differential. This provides some economic incentive for producers without existing refinery outlets for their bitumen, and in conjunction with moderating capital costs, a strong oil price level, and the rapidly growing need for a flexible crude supply in Asia, leads to healthy investments in upgrading projects in the province.

Throughout the scenario the Alberta government tweaks the royalty regime for oil sands, including some increases for bitumen-only producers with a higher rate of return. However, these tweaks do not materially change the guiding principles of charging lower royalties prior to payout and using rates that change with the WTI price.

Bitumen producers enjoy relatively strong prices for their product during the first decade of the scenario. Not only does the rise in the benchmark light, sweet crude oil price lift all boats, but the supply of heavy crude relative to light crude around the world tightens slightly. Heavy crude prices are less deeply discounted to light crude as a result. Bitumen prices average approximately 80 percent of the WTI price from 2010 to 2020, a significant improvement from the 70 percent level seen during 2005–08.

## Favorable Conditions for Increasing Market Access

To support an aggressive ramp-up in production, downstream markets need to be developed and logistical links to these markets must be built. By 2012 approximately 1.3 mbd of expanded pipeline capacity from Alberta to the US Midwest is completed.*

During 2010–20 several refineries in the US Midwest complete expensive overhauls to allow their facilities to process diluted bitumen. At the same time, overall demand for oil is rebounding from the deep decline of 2008–09. From 2010 to 2020 North American demand increases by nearly 2 mbd. During this period, total imports of diluted bitumen into the US Rocky Mountain and Midwest regions (traditional markets for oil sands products) grow by almost 850,000 bd. The US market for SCO also expands during this period, especially as local availability of light, sweet crude declines.

As the US Rocky Mountain and Midwest markets become saturated, however, new outlets for oil sands material are required. Beginning in 2014 bitumen prices find significant support owing to the completion of a large new 500,000 bd pipeline, followed by another 450,000 bd pipeline in 2020, which allow diluted bitumen to flow from Alberta all the way to the huge, sophisticated refining nexus of the US Gulf Coast. With this critical link established, bitumen producers in Canada are finally able to fetch the same world price for heavy crude as other producers that sell into the US Gulf Coast, such as Mexico and Venezuela. In 2018 SCO and synbit producers access new markets on the East Coast with the reversal of Line 9, a pipeline that currently flows from Montreal to Sarnia. This reversal allows significant shipments of oil from Alberta to Quebec.

This link to world markets is further solidified by the expansion and addition of new pipeline capacity to the West Coast. Existing pipeline capacity linking Alberta with the Greater Vancouver area is expanded by nearly 400,000 bd by 2015, and by 2023 another pipeline is added, a 525,000 bd pipeline linking oil sands producers with the deepwater port of Kitimat, British Columbia. Before they can proceed, these projects require careful negotiations between the provincial government, the oil companies, and the First Nations who live along the pipeline corridor, who are initially opposed to further disturbance of their lands and hunting grounds. Ultimately, the First Nations leadership and industry enter into a partnership agreement in which the First Nations groups are granted an equity stake in the pipeline. This collaborative effort is seen as a way to improve the long-term economic development of the First Nations communities.

Critically, the new west coast pipeline is built only with the strong support of the Canadian federal government, which is driven by its mandate of a strong energy policy and strategic goal of diversifying the country's energy export markets. The federal government plays an important role in working with local community stakeholders to get the necessary approvals for the project, such as allowing supertankers access to Kitimat.

*Three pipeline projects—Enbridge's Southern Access line, its Alberta Clipper project, and TransCanada's Keystone line—are currently under construction and assumed to be operational by 2012.

### The Diluent Challenge

Bitumen cannot be transported by pipeline without diluent, and adequate diluent availability is a recurring challenge in the Barreling Ahead scenario. Diluent prices are strong early in the scenario as bitumen producers require increasing volumes of diluent to pipe their product to new customers in the United States. To alleviate this stress, a 180,000 bd pipeline from Chicago to Edmonton is completed by 2013, allowing recycled diluent (along with significant volumes of diluent brought up from Mont Belvieu, Texas) to be shipped to Alberta producers. By 2023, as demand for diluent begins to push up against the capacity of this first pipeline, a second diluent pipeline is completed, this time flowing from Kitimat, British Columbia, to Alberta. This pipeline allows supertankers loaded with diluent from distant Asian markets to ship their product to oil sands producers in Alberta. These supertankers are then able to backhaul bitumen and SCO to refineries in Asia.

### Diversified Markets and US Energy Security

With the West Coast link completed, diluted bitumen or SCO can now be loaded onto supertankers to reach the oil-hungry and rapidly developing markets of Asia as well as to US West Coast refineries, which are in need of new supplies as Alaskan North Slope and California heavy crude production declines. This export pipeline link to Canada's west coast is a key victory for the government of Canada in its quest to diversify its energy market outlets. It is also a major benefit for oil sands producers, as their products are now able to fetch world market prices, instead of being price disadvantaged by their "landlocked" position. Total world liquids demand grows by nearly 30 mbd from 2009–35 in this scenario, with the majority of the growth occurring in China, India, and other rapidly developing Asian nations.

Despite this important diversification to markets outside of North America, the oil sands become a cornerstone of US energy security in Barreling Ahead. As US domestic crude production and Mexican and Venezuelan crude production declines, the oil sands' share of total US crude imports rises from approximately 7 percent in 2008 to nearly 40 percent by 2035.

### The Quest to Contain Industry Costs

Spiraling capital costs were a key limiting factor to oil sands development prior to the crash in 2009. Double-digit industry inflation was the norm during 2005–08. The breakeven price for upgraders drifted steadily upward, and cost overruns and project delays were endemic. In the Barreling Ahead scenario these cost pressures do not disappear. However, they do moderate once innovative solutions are found.

Initially the average capital cost of new oil sands projects declines over 20 percent from the 2008 peak to 2010 owing to the deep world recession and the associated pullback of oil sands projects, the depreciation of the Canadian dollar, decreases in Alberta labor costs, and increases in labor productivity. Falling prices for key commodities such as steel and copper—a reflection of the global economic recession—also contribute to lower costs.

Once activity kicks back into high gear, however, costs spike again as demand for labor revives and the strong global economy feeds into much higher costs for equipment, steel, and cement. By 2015 the cost to build new oil sands projects is fast approaching the 2008 peak pricing levels in real terms. Over 33,000 mobile construction workers are back in Alberta—nearing the peak seen during 2007–08.

The oil industry, the Alberta government, and the federal government all recognize that the labor, equipment, and engineering shortage of 2005–08 must be avoided if the industry is to grow. This time they craft a proactive and collaborative plan to address industry bottlenecks, including investment in major labor retraining programs.

Workers are recruited from across Canada and around the globe; incentives are provided to encourage expansion in equipment manufacturing and module fabrication capabilities in the province and throughout Canada. The oil sands industry taps the significant capacity for both engineering design and equipment manufacture in Asia. Gradually, Asia supplies an increasingly significant share of industry capacity.

The key breakthrough in cost management comes by the end of 2016, when producers successfully deliver large equipment modules into the oil sands region from the Beaufort Sea and down the Mackenzie River to Lake Athabasca. The plan, which was advanced in both planning and feasibility stages in the 2008–10 boom, is fast-tracked by industry with strong support of the federal government, which pushes for efficient passage of the necessary regulatory assessments and approvals. This novel logistical innovation—dubbed “The Longest Module” by the industry-government consortium—removes a major bottleneck in project execution by allowing large and complex equipment modules to be built in fabrication centers outside of Alberta, significantly reducing the labor and fabrication requirements within Alberta. Capital costs and labor requirements associated with construction in the Athabasca region are reduced substantially, providing further impetus to continued growth in the oil sands sector throughout the scenario.

Using this northern route to move oil sands equipment modules also creates economic and social opportunities for First Nations groups in the Fort Chipewyan region. As with the pipeline project to the West Coast, these Aboriginal communities become equity partners with the module transportation industry. This new module-moving business creates long-term jobs in the community. An additional benefit to this community includes the construction of an all-weather road from the previously isolated region to Fort McMurray.

One trade-off of this logistical innovation in module production is the offshoring of many jobs from Alberta and Canada. However, ultimately it creates a more sustainable economic development path for both industry and the Fort McMurray region, keeping labor demand within the available supply in Alberta and decreasing the need for out-of-province and out-of-country workers that led to significant cost escalation and labor productivity issues during the mid-2000s boom.

Throughout the scenario operating costs of oil sands projects remain well below the price of crude oil, allowing project economics to remain healthy. Thermal project operating costs average $25 per barrel (constant 2008 US dollars) by the end of the scenario and under $30 per barrel for integrated mines and upgraders.

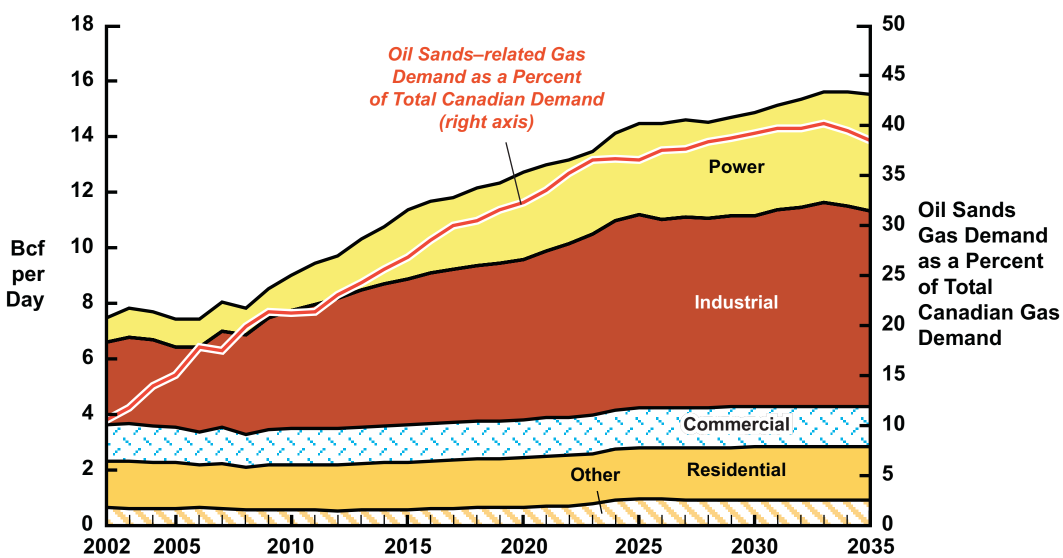
## The Gas Constraint and the Need for Alternatives

Natural gas consumption soars in the Barreling Ahead scenario. Efforts to secure gas supply and to minimize its use loom larger with each passing year. Mining operations, upgraders, and in-situ facilities, which use gas to generate steam, produce hydrogen, and power their sites, consume 6.3 Bcf per day at their peak in 2033. At this volume gas demand in the oil sands sector reaches nearly 40 percent of total gas demand in Canada (see Figure IV-8). When gas prices spike, this creates tension between eastern and western Canadian politicians. In the east much is made of the higher cost to heat homes because of the "great sucking sound" of gas use in the oil sands.

New gas supplies from the Mackenzie Delta in 2020 followed by Alaskan North Slope gas in 2023 are critical to meeting the increasing needs of the oil sands. The incremental volume from these new sources—6.5 Bcf per day—is approximately equal to the total volumes required by the oil sands at their peak. Annual average Alberta hub gas prices rise from $4.50 per MMBtu (constant 2008 US dollars) in 2010 to nearly $12 per MMBtu by 2035 owing to this persistent demand-side growth.

**Figure IV-8**

**Barreling Ahead Scenario:**
**Canada Total Annual Natural Gas Demand**




Source: Cambridge Energy Research Associates, Statistics Canada.
90107-15_1404

Throughout the period other ideas for steam generation are investigated, but none prove economical compared to natural gas, and gas consumption continues to grow as a result. Despite these new flows of gas from the north, by the second decade of the scenario the handwriting is on the wall for the industry. Rising gas prices are eating into industry margins. The Canadian government has become increasingly alarmed at the rate of gas consumption and, in an effort to moderate this trend, applies a heavy tax to the price of natural gas consumed by oil sands operators. It becomes clear that further growth will depend on the adoption of new technologies to move the oil sands off natural gas. By 2025 new upgrader facilities, which traditionally run on natural gas, switch to gasification of either petroleum coke (a by-product of the upgrading process) or asphaltenes. At the same time new in-situ projects switch to using excess syngas and steam, produced from the upgrading facilities, to offset their natural gas consumption. Not all in-situ operators can economically obtain excess syngas and steam, however. For example, in-situ operators separated from upgraders by long distances instead generate steam by combusting the heaviest fraction of the bitumen they produce. These “bottom of the barrel” bitumen fractions are obtained via on-site simple distillation units and partial field upgrading units. One of the trade-offs to moving away from natural gas toward alternative steam generation technologies such as gasification and burning the bitumen bottoms is an increase in the carbon intensity of these oil sands projects.*

Technologies that do not require steam, such as in-situ combustion techniques, are also introduced commercially at this time. By 2035, 10 percent of all in-situ output is predicated on either gasification or in-situ combustion technologies. Even with the relatively high natural gas prices and a decrease in gasification costs resulting from two decades of technical innovations, the economics of switching to gasification still work only with the imposition of a tax on natural gas by the government and strong incentives such as accelerated depreciation and capital tax credits. This tax structure ensures that industry makes the switch for new projects—although the economics to retrofit existing investments is not supported.

## THE ENVIRONMENT: RAPID GROWTH LEADS TO ENVIRONMENTAL CHALLENGES

An aggressive scale-up of the oil sands imposes substantial burdens on the environment. Advances in technology mitigate the impact, but do not prevent GHG emissions from rising sharply. Rapid oil sands development also creates intense local environmental and social pressures. While economic growth is the primary driving factor in this scenario, operators also need to address the cumulative impacts of rapid oil sands development. For this reason, in 2011 industry and government form the Research and Innovation Network (RAIN) for the oil sands, a collaborative research and development (R&D) center intended to address many of the long-term environmental issues surrounding the oil sands. RAIN is intended to ensure that adequate budgeting for R&D is sustained throughout the inevitable boom-and-bust oil price cycles, and is a key catalyst for some of the technological innovation in the scenario.

*The GHG emissions associated with gasification and combusting bitumen bottoms can be more than twice that of natural gas use because the carbon content of petroleum coke is twice as high as natural gas, and the efficiency of gasification is lower than for natural gas combustion.

## Weak Effort to Contain Carbon Emissions

In this scenario of high global economic growth, emissions worldwide grow substantially, and hence most countries do not achieve targeted emissions reductions that are currently being discussed as part of the successor treaty to the Kyoto Protocol. Climate change remains an important issue in both Canada and the United States throughout the Barreling Ahead scenario. However, with the great recession of 2008 and 2009 still a painful memory, policymakers are wary of imposing huge new costs on a fragile North American economy in the midst of a rebound. As a result a "middle of the road" approach is adopted. A federal $CO_2$ cap-and-trade program in both the United States and Canada is agreed upon in 2010 and implemented in 2015. But this program only covers parts of the North American energy market. The point of regulation closely mirrors the EU Emissions Trading Scheme in that it only regulates power plants and large industrial emitters (including bitumen upgraders). In a move that helps to limit the cost of implementation, $CO_2$ allowance prices are actively managed through a safety valve—a price cap that prevents allowance prices from surpassing $35 per metric ton (real 2008 US dollars).

$CO_2$ allowance prices at these levels are not high enough to support the economics of CCS. Even with strong government incentives, oil sands operators in the Fort McMurray region do not pursue CCS in this scenario. The economics of carbon capture do not make sense at these carbon price levels, and Fort McMurray does not have the geological formations to support sequestration. The $CO_2$ must be transported to the Edmonton area (which has geological formations more appropriate for carbon storage), which only worsens the economics. In this scenario CCS is limited to the Edmonton area, where coal-fired power generation and hydrogen plant capacity in "Upgrader Alley" allow carbon to be captured relatively efficiently. Despite the higher emissions at some sites that generate steam by combusting bitumen bottoms or syngas, by 2035 the emissions from the oil sands start to decline as lower SORs combined with a move to in-situ combustion technologies start to reduce total emissions.

## GHG Emissions Jump

GHG emissions from oil sands facilities increase from 40 mt in 2008 to more than 170 mt in 2035.* This more than fourfold increase occurs despite some gains on the emissions front; the GHG intensity of each barrel of oil sands production improves by 10 percent between 2008 and 2035, driven primarily by the benefits of better SORs. Greater overall improvement in GHG emissions intensity is hampered by the move away from natural gas consumption to the more carbon-intensive process of gasification of petroleum coke and asphaltenes. GHG emissions from oil sands production represent approximately 20 percent of total Canadian GHG emissions in 2035 (an increase from about 5 percent in 2008).

Although substantial on their own, GHG emissions from the oil sands facilities represent about 2 percent of total North American emissions by 2035 and less than 0.5 percent of total world GHG emissions (see Figure IV-9). It is also unclear whether the arc of GHG emissions would be substantially different in the absence of oil sands development. Since

*This includes the emissions associated with production and upgrading but does not include refining or consumption of the final refined products.

a central premise of this scenario is strong world oil demand growth, if the oil sands were not developed the majority of the liquid fuel needed to meet this demand would need to come from another source. The GHG impact of this substitution would depend entirely on the future quality of the liquid fuel replacing the oil sands, which is uncertain.*

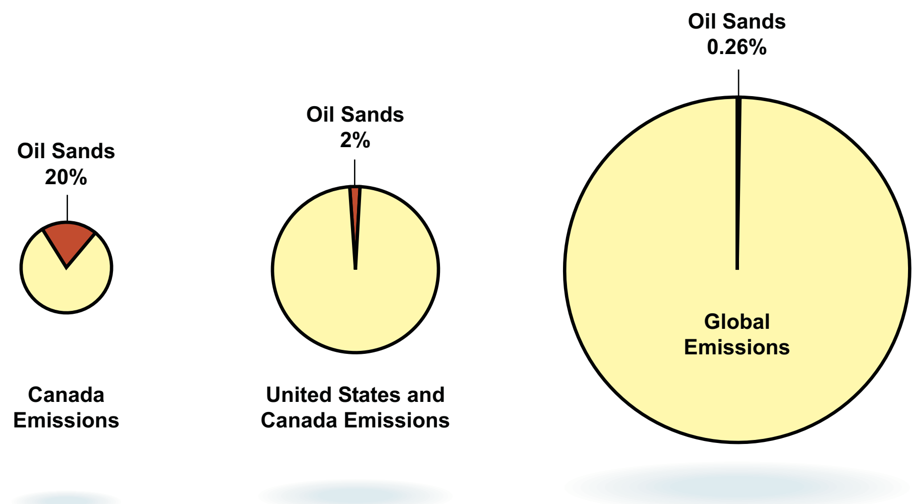
## The Struggle to Address Local Environmental and Social Impacts

Water management is a critical component of the Barreling Ahead scenario. Mining operations, which depend on water from the Athabasca River, make up half of total oil sands operations by 2035. Combining current water licenses, applications for projects under review, and estimates of future project allocations results in nearly 860 million cubic meters of water per year allocated from the river by 2035, nearly a threefold increase from current levels.

**Figure IV-9**

**Barreling Ahead:**
**2035 Oil Sands Greenhouse Gas Emissions**

*In 2035 for the Barreling Ahead scenario, GHG emissions from Canadian oil sands production reach approximately 170 million metric tons.**




Source: Cambridge Energy Research Associates.
*Considering facility-level GHG emissions for production and upgrading in Alberta.
90107-21

*As light, sweet crude availability around the world declines over time, heavier crude resources (which generally require more energy to extract and process) will increasingly be developed and gain a larger share of the world's primary energy production. However, production of natural gas liquids and condensates (which are very light and are less energy intensive from a life-cycle perspective) will also likely increase as global natural gas development grows. Both of these liquids—heavy and light—could be substitutes for the oil sands.

Given the limitations on water availability from the Athabasca River during the low-flow winter months, oil sands operators will not be able to draw their full water allocation from the river during the winter. Advancements in water management must be made.

Phase II of the Athabasca River Water Management Framework is released in 2010, further reducing allowed withdrawals from the river during the winter. Industry struggles to meet its water needs under this new paradigm, because storing the vast quantities of water needed would require them to store water on large portions of their leases instead of extracting bitumen from them. The negotiated solution is the development of an upstream dam on the Athabasca River that evens out seasonal river flows, eliminating winter withdrawal restrictions. The dam also generates electricity and GHG offsets from hydropower generation, although the trade-off is the creation of other environmental concerns typically associated with dams.

Additionally, Alberta's Energy Resources Conservation Board has issued mandatory directives for industry to develop an effective reclamation process to convert fluid fine tailings to trafficable areas. Some of the process water trapped in the fluid fine tailings is recycled, reducing the need to draw water from the Athabasca River. Over the course of this scenario this dewatering advance slightly reduces the overall volume of water used per barrel of bitumen produced from about 4 barrels of water to 3 barrels.*

However, tailings management and site reclamation prove challenging in this scenario given the rapid pace of development. Operators struggle to meet the tailing directive's requirement to eliminate the accumulation of fluid fine tailings. Additionally, no regulation requires the treatment of legacy tailings—those produced over past years of mining. Industry relies on EPLs to incorporate this waste into the reclaimed landscape. These lakes become an environmental question mark, with doubts that they can ever evolve into ecologically productive water bodies. The first full-scale EPL is in place by 2015, but at least a decade passes while operators learn how to make EPLs as ecologically productive as possible. Land reclamation also begins to progress by 2015, but the pace of reclamation does not keep up with the pace of land disturbance from new mining projects in this scenario. In addition fragmentation of the forest due to infrastructure development for in-situ projects results in a reduction of local biodiversity.

In-situ developments continue apace, resulting in some water use challenges. In-situ developments are less water constrained than mining operations because they often use brackish water from deep aquifers for steam generation, and not the Athabasca River. However, capacity growth of in-situ oil sands operations in Barreling Ahead more than triples water use, even with the industry average SOR declining from today's level of 3 to 2 by 2035. Although the hydrogeology of the oil sands area is not fully understood at first, ultimately the groundwater resources prove productive enough to support the growing water demand.

The incredible pace of development of oil sands in this scenario highlights the important role of the Oil Sands Secretariat in optimizing plans for economic development, sustainable environmental objectives, and infrastructure developments. The Secretariat creates several

*Not all water used in mining operations is drawn from the Athabasca River. Even in 2008 a substantial share of water was drawn from site runoff and mine dewatering.

smaller communities in the Regional Municipality of Wood Buffalo that allow workers to live closer to their jobs, taking the pressure off Fort McMurray as well as minimizing temporary housing. This change leads to more sustainable and socially harmonious communities. Diversion of royalty money from the province to the Regional Municipality of Wood Buffalo is very important in this scenario to allow needed infrastructure improvements to support the growing population, including investments in transportation, health care, education, and other community services.

## DEEP FREEZE SCENARIO: KEY INSIGHTS

**Insight 1.** The world oil price is the number one driver of oil sands production. Even though costs decline sharply by the end of the scenario in Deep Freeze, bitumen prices still need to reach over $30 per barrel (constant 2008 US dollars) in 2035 to support investment—a level above the benchmark light, sweet crude oil price at that time.

**Insight 2.** A prolonged period of low oil prices could lead to a drastic decline in valuation for many operators in the oil sands. This could create the opportunity for companies with strong balance sheets to acquire oil sands operations at deep discounts. Consolidation in the industry would be likely, with multinationals taking over independents.

**Insight 3.** Oil sands operators will need to ensure they have access to downstream markets in a world in which demand is stagnant or decreasing. Vertical integration between upstream producers and downstream processors could therefore become more critical.

**Insight 4.** Downstream investments are at risk in a low price environment. Pipelines have been built and oil companies are retooling their refineries in anticipation of rising supplies of bitumen in this scenario. However, if production growth of oil sands stops, these refineries may find themselves competing for limited supplies of oil sands supplies and bid up the price.

**Insight 5.** Although large greenfield investments are unlikely in this scenario, plummeting construction costs could give an advantage to incumbent producers looking to expand production of existing facilities. Operating costs for existing producers are also relatively low in this scenario.

**Insight 6.** In a low oil price environment the pace of technology advances in the oil sands sector could be surprisingly strong. Pressures to keep costs in line will be intense and technology will be part of the solution.

**Insight 7.** Absent transformational technology adoption, the most important driver of GHG emissions growth in the oil sands is the pace of production growth, not adoption of new carbon abatement technology. CCS and nuclear are not deployed in the Deep Freeze scenario, yet GHG emissions growth is the weakest in this scenario since output growth stalls.

**Insight 8.** The economic benefits accruing to Canada from the oil sands industry in this scenario would be relatively weak. In addition to lower annual revenue, by 2035 there would be fewer jobs directly and indirectly related to the oil sands than currently.

## A LOST DECADE: THE ECONOMIC AND ENERGY CONTEXT OF DEEP FREEZE

Economic growth is one of the key drivers for oil demand and oil prices. What if the great recession that took hold in 2008 and 2009 is just the prelude to a "great stagnation"? What if globalization—the prevailing economic paradigm of the past several decades—loses ground to the forces of nationalism, insularity, and protectionism? How will the Canadian oil sands fare in such a challenging world of lower economic growth?

These are the key premises explored in the Deep Freeze scenario. In this scenario there is a sense throughout society that unfettered free markets have failed. The "commanding heights" of the economy shift back toward governmental control, with greater political and regulatory oversight throughout the economy. And yet this shift to a greater role for government does not result in a rebound in economic growth—rather, the economy stagnates. Oil prices remain at depressed levels, reflecting a long period of anemic world demand. In this environment high-cost, marginal sources of oil—such as the Canadian oil sands—face a long fight for survival.

### A Prolonged Economic Disaster and a "Super Slump" for Oil Prices

By 2010 it is clear that the financial and economic crisis that began in 2008 is becoming the "great stagnation." Deep and intractable structural problems within the US economy and indeed the greater world economy continue to fester, despite massive government spending. The economic fallout has serious political ramifications. A simmering frustration with globalization and its effects on the economy, society, culture, and economic security emerges into full backlash in many countries—from North America and Europe to developing economies in Asia. The whole essence of globalization comes much more into question, and a wave of insularity begins to sweep through many countries and regions. The result is a period of increasing bank failures, economic stagnation, and growing protectionism. Beggar-thy-neighbor sentiment starts to creep into the global political-economic landscape.

The decade from 2010 to 2020 is one of sustained low global economic growth—only averaging 2.5 percent, compared with 4.5 percent achieved from 2003 to 2008. Demand for most commodities, including oil, remains weak. Oil demand in North America only begins to grow again consistently post-2020. Oil prices enter a "super slump," with the light, sweet crude benchmark hovering just below $30 per barrel in constant 2008 US dollars ($34 in nominal terms) from 2010 to 2020.

By the second decade of the scenario the world economy has begun to recover. However, the overhang of spare capacity in the world oil market keeps oil prices relatively weak, and prices continue to drift downward, averaging only about $25 per barrel in constant 2008 US dollars ($41 in nominal terms) from 2020 to 2035. In this scenario global liquids demand growth increases only 14 mbd from 2009 to 2035—annual average incremental growth of only about 550,000 bd.

### Energy Security Remains Important as Geopolitical Unrest Spreads

Deep Freeze is also a world of heightened global tensions and political insecurity. The sense of global community gives ground to renewed nationalism and separatism. Episodes of terrorism as well as the proliferation of nuclear and other weapons contribute to the environment of fear and uncertainty.

Geopolitical instability in the Deep Freeze scenario magnifies the importance of energy security to major oil importers such as the United States. Despite the low oil price environment, there is a strong desire in the United States to reduce dependence on “foreign oil” through development of domestic resources and imports from “friendly” and secure countries. In this respect Canadian oil and gas reserves are high on the list of secure supplies. Even in this scenario of low oil sands production, Canada’s share of total US crude imports still climbs to 23 percent by 2035.

## OIL SANDS DEVELOPMENT: WAITING FOR THE THAW

Without question, the economic and oil price environment of Deep Freeze is the most challenging of the three scenarios for Canadian oil sands producers. The oil sands boom is now followed by the great—and long—bust.

With light, sweet crude prices hovering below $30 per barrel in constant 2008 US dollars ($34 in nominal terms), operating projects in the oil sands are able to just cover their cash costs, but the economics of new oil sands investments are dismal. Only new projects well into their construction phase now proceed, leading to some continued growth in the early part of the scenario’s first decade. By 2013 production has reached 1.8 mbd, but the development process for new oil sands projects comes to a virtual halt. Overall capacity growth has stopped. Once initial momentum subsides, the industry is basically in a deep freeze.

A generational retreat from growth in oil sands production in such a scenario is not preordained, however. Several factors allow some moderate production growth by the second decade of the scenario:

- **Declining costs support incumbent producers.** Reduced project activity throughout the energy sector and depressed commodity prices lead to a steep decline in capital costs (50 percent from 2008 peak in real terms by 2035). Capital costs do not drop enough to allow for an adequate return on investment for new oil sands investments, but they do drop low enough to allow existing capacity to conservatively expand production.

- **A recovery in oil demand.** A sustained period of low prices ultimately leads to a recovery in oil demand by the second decade of the scenario. Expensive alternatives to petroleum such as biofuels and electric vehicles do not thrive as much as in other scenarios.

- **A weaker emphasis on carbon mitigation.** A poorly performing world economy results in only marginal increases in carbon emissions in this scenario. Expensive schemes to price carbon are seen as counterproductive in such a low growth world.

### Small Consolation for Producers: Lower Costs and Competition for Bitumen

There is a faint silver lining for oil sands producers amid the wreckage of the bust: capital costs for new projects plummet from their 2008 highs.

Initially, as the slowdown in Alberta and other oil producing regions around the world reduces demand for equipment, labor, and services, capital costs drop 20 percent through 2010 from their 2008 peak. Post-2010 the rate of cost decline continues, although at a more moderate pace. Prices for many project components hit the “cost floor”—their cost of production. Prices for other commodities such as steel and cement remain low amid weak world economic growth and sluggish demand for these key inputs. In this scenario, especially the first half of the period, the number of suppliers for engineering and oilfield equipment exceeds demand, keeping downward pressure on project costs.

A low number of oil sands–related projects, combined with few energy-related projects in North America, keeps the Albertan labor market much looser than it had been previously. From 2010 to 2020 demand for craft labor in Alberta evaporates, averaging less than 5,000 mobile workers (compared with a peak of over 36,000 workers in 2008)—less than 25 percent of Alberta’s supply of workers. Real labor costs decline as a result (resulting from increased productivity, wage freezes, and decreased costs for incentives such as per diem payments and bonuses) and remain relatively low throughout the remainder of the scenario.

For the highest-cost producers—bitumen upgraders—these sharp reductions in costs are not enough to offset low world oil prices. In 2015, for example, new SAGD production with an integrated upgrader requires a WTI price of more than $50 per barrel (constant 2008 US dollars) to meet a 10 percent return-on-investment hurdle rate—well above the prevailing crude prices. Although costs decline, reducing the required WTI price to $40 per barrel by the end of the scenario, this is still above the average light, sweet crude oil price. As a result, upgrader investments never recover in this scenario. However, incumbent bitumen producers are able to take advantage of lower capital costs to conservatively expand production as needed by the market. Small capacity expansions that are able to leverage existing infrastructure have positive economics, especially in the first half of the scenario period, when heavy-light differentials narrow.

Although new projects are generally uneconomic in this scenario, existing projects can cover their variable costs, which average $12 per barrel for a SAGD project and $20 per barrel for a integrated mine and upgrader project. Owing to these relatively favorable economics for incumbent producers, over 30,000 bd of capacity creep is added on average each year from 2020 to 2035 by brownfield expansion of existing facilities.

## Economics and Government Incentives

Preserving and creating jobs becomes the pressing issue of the day in this scenario. Total spending related to oil sands developments averages more than C$20 billion (real 2008 Canadian dollars) per year. By 2035, 200,000 jobs are directly or indirectly related to oil sands—fewer than at the end of the great boom years of 2000–08. The vast majority of these jobs are long-term operations jobs, since minimal new construction occurs toward the end of the scenario. From 2025 through 2035 revenues to municipal, provincial, and federal governments average more than C$3 billion (real 2008 Canadian dollars) per year, less than government revenues in 2008.

With benchmark light, sweet crude oil prices averaging below $30 per barrel, royalties paid to the Alberta government are at the lowest level possible on the sliding scale. The federal government attempts to improve project economics by giving back tax incentives (removed in the 2007 budget), allowing accelerated depreciation of capital costs. However, in this crude oil price environment the Alberta or federal government can do little to improve project environments by reducing royalties or changing tax structures.

Aboriginal concerns regarding oil sands developments fall by the wayside as jobs become a high priority in the face of dramatically slowed development. The Oil Sands Secretariat faces new challenges in assessing the correct pace of infrastructure development to meet new economic realities and stimulate job creation. Through a system of royalty relief and tax credits, the Secretariat attempts to increase the incentives for upgrading and further processing initiatives (for example, field upgraders and integrated power facilities with the capability of exporting surplus power to the grid). But with oil prices remaining stubbornly low, these incentives are unable to spur new investment.

Relatively weak natural gas prices provide another small buffer for producing economics in this scenario. Natural gas supplies in Canada are relatively abundant in the Deep Freeze scenario—owing partly to the absence of a strong demand pull that a growing oil sands sector would otherwise provide. Productive capacity in the Western Canada Sedimentary Basin reaches 18 Bcf per day in 2024 and is augmented by an additional 2 Bcf of gas flowing from the Mackenzie Delta starting in 2023. Gas prices slump initially, along with crude oil prices, with Alberta hub prices dropping to under $3 per MMBtu (constant 2008 US dollars) by 2020. Gas prices rise modestly in the second half of the scenario.

Intense operating cost pressure in Deep Freeze motivates continued advances in technology. These are evolutionary in nature but result in a continued lowering of SORs in SAGD projects to an average of 2 by the end of the scenario, together with improvements in drilling, downhole pumps, use of hydrocarbon solvents, and steam distribution.

Bitumen producers have another small consolation in this scenario. Although absolute crude oil prices are low, bitumen pricing is relatively robust at the start of the scenario. This occurs as several US Midwest refineries retool their facilities during 2009 to 2016 to process over 600,000 bd of additional diluted bitumen instead of conventional crude oil. Over 1.6 mbd of pipeline capacity to ship bitumen to these markets is also completed during this time. These refining and pipeline projects were conceived, planned, and begun before the economic crisis, when bitumen supplies were expected to be plentiful and pricing advantageous to refiners.

As new oil sands projects are halted, however, these refineries—which have now completed costly revamps of their facilities to specifically run bitumen—must compete for now-limited bitumen supplies or switch crude slates and absorb the high costs incurred with processing crudes that are not optimal for their facilities. The scarcity of heavy crude in North America is magnified by continued declines in heavy crude production in Mexico and Venezuela. Indeed, production declines from these traditional heavy crude suppliers accelerate from 2010 to 2020, as the low world oil price prevents them from making the type of large-scale investment needed to shore up production.

As a result of this tightening balance for heavy crude, bitumen's discount to light, sweet crude oil is narrow during the first part of this scenario, and bitumen trades above the price of similar heavy, sour crudes in the US Gulf Coast such as Mexican Maya. Deep conversion refiners that are exposed to this narrowing differential face a poor return on investment as a result, and new investments in deep conversion refining capacity are scrapped. Planned pipelines to the US Gulf Coast and Canada's west coast are similarly canceled. These are an unambiguous market signal to oil sands producers to keep major new investments on hold.

In this scenario diluent is initially in short supply until a pipeline is finished that can recycle diluent from Chicago (along with diluent supplies brought up from the Gulf Coast) back to producers in Edmonton. At this point diluent becomes relatively oversupplied, as the pipeline exceeds the required amount of diluent.

## Oil Demand Comes Out of Hibernation

By 2020 oil demand in North America is finally on the upswing, stimulated by the prolonged period of low oil prices in the previous decade and a resumption of stronger economic growth. Oil sands productive capacity growth resumes tentatively. Expansion is largely a result of debottlenecking efforts and modest brownfield investments, since the oil price remains too low to support large-scale new investments. Average annual growth from 2020 to 2035 is only 30,000 bd, and new capacity additions slow to less than 20,000 barrels per year for the last ten years, limited to brownfield expansion of existing bitumen production since upgrading economics remain out of reach. The growth in world oil demand is primarily met by lower-cost oil fields, not the oil sands.

Gas demand for oil sands production reaches 1.5 Bcf per day in 2035 for in-situ and mining, while gas demand for upgrading reaches 1.1 Bcf per day in 2035. With gas relatively plentiful and prices modest, alternative technologies such as petroleum coke or asphaltene gasification or in-situ combustion techniques are not needed and not developed commercially.

## The Environment: The Impact of Lower Growth

In the Deep Freeze scenario's grim world of sustained low economic growth, environmental issues gain less traction. Although international discussions continue on a new climate change protocol, no real progress occurs as all countries now focus on the more pressing issue of restarting economic growth. The urgency to act quickly on climate change also declines owing to a significant slowdown in growth of GHG emissions. The rate of fossil fuel consumption growth moderates in line with slower economic activity. Although this slowing in emissions growth does not result in a significant change in atmospheric accumulation of GHG, it does reduce public alarm about growing emissions.

Discussions to limit GHG emissions at the global level break down in Copenhagen in 2009, and as a result the United States and Canada both continue to delay on the issue. In the interim some of the state and provincial policies move forward, but with little fanfare and with limited success at actually reducing emissions. However, the issue of carbon abatement does not fade completely, and by 2025 a carbon cap-and-trade program is negotiated between the United States and Canada. However, $CO_2$ prices are capped and held below $10 per metric ton (constant 2008 US dollars).

With carbon prices low and less urgency to develop new technologies for carbon abatement, CCS is not commercially developed in the Deep Freeze scenario. As a result oil sands GHG emissions grow under this scenario. By 2035 GHG emissions associated with oil sands production climb to about 60 mt per year, accounting for about 8 percent of total Canadian GHG (an increase from about 5 percent in 2008). The overall emissions in the Deep Freeze scenario are lower than in the other two scenarios, despite the absence of carbon-abatement technologies such as CCS, nuclear, and in-situ combustion techniques. Adoption of these technologies reduces emissions intensity, but slower growth in oil sands production has the biggest impact on aggregate emissions.

The deep and prolonged economic downturn means that oil sands projects must be managed in a world of slow growth and poor project economics. The implementation of recently enacted regulations on tailings management and water recycling is delayed as a way of preserving the economic viability of existing projects. New targets are set in keeping with the industry's ability to pay in a low growth and low oil price environment. Nevertheless, some improvements are made in water use and tailings management. Mining operations reduce fresh water use and store water to avoid exceeding the Athabasca River's winter low-flow withdrawal limits. The relatively small amount of water that needs to be stored in this scenario means that each operator decides on its own summer month water storage strategy, such as adding extra water to its existing tailings ponds or using mined-out areas to store water inventories. The expense and technological challenge of dewatering tailings results in only incremental progress in eliminating fluid fine tailings. Since little water is available to recycle from tailings, the rate of mining water use remains relatively stagnant in this scenario at approximately 4 barrels of water for every barrel of bitumen produced. Ultimately, EPLs are required to store tailings in the reclaimed landscape, and the pace of reclamation is slow as operators struggle to pay for reclamation efforts. Research on wetlands restoration stalls due to lack of funding, and reclaimed land consists primarily of highland forest and EPLs.

# CHAPTER V: CONCLUSION

# CHAPTER V: CONCLUSION

## INNOVATION ACROSS ALL SECTORS

When Dr. Karl Clark cracked the code to separate the oil from the sand nearly a century ago, it was the first of many challenges that were overcome in the story of the Canadian oil sands. Innovation has been a continual part of the story ever since. In the 1990s cooperation between government and private industry led to the development of steam-assisted gravity drainage (SAGD), one of the major techniques that offers a way to unlock the 80 percent of oil sands resources that are too deep to mine. Indeed, the history of the oil sands shows how the cumulative effect of innovation, research, government policy, and private capital have made the oil sands one of the most important sources of oil supply growth in the past decade and potentially in the decades ahead.

As a result, the oil sands today have moved from the fringe of energy supply to the center. Their commercial development makes Canada the world's second largest holder of recoverable oil reserves and an increasingly important part of the fabric of hemispheric and global energy security. The development of this oil resource has become an important source for economic growth. The oil sands have become a vital element in the $597 billion of US-Canadian trade and the overall relationship between Canada and the United States. They are a major part of the network of energy trade—involving also conventional oil, natural gas, and electric power—that binds the two nations together. They have made Canada the largest oil exporter to the United States, connected by pipelines and adjacency. They have the potential for significant future growth, contributing further to supply and security and helping to provide balance for the global energy system. Recognizing the significance and impact of oil sands is very important, and approaching the questions about oil sands in an appropriate fashion is essential. To do otherwise is to risk wider disruption in US-Canadian relations, with significant economic and security impacts.

But new challenges face the oil sands industry. The world's most severe economic downturn in decades has cast a chill on many investment plans. Also, like other energy sources, the oil sands will be affected by the future path of greenhouse gas (GHG) regulation in Canada and the United States. Sometimes, however, there is a tendency to take the current status quo, a moment in time, as the fixed outline for the future. But innovation is not static. Since 2000, the amount of steam used in SAGD has been cut in half, significantly reducing GHG emissions on a per-barrel-of-output basis. As in the past, technology and process advancements will lead to greater efficiency and new ways of doing things, which in turn will enhance investment economics and improve the GHG footprint of oil sands.

How will the oil sands evolve? The pace of their development could move in several different directions, as illustrated by our scenarios. Realization of the oil sands potential, while also requiring environmental protection, means finding an appropriate balance among governments, oil sands operators, investors, local communities, and nongovernmental organizations.

But how is a balance to be found? Moving toward a shared understanding of benefits and risks is essential to productive dialogue among stakeholders. That means getting the GHG question into a comparable framework, which indicates that the oil sands, on a well-to-wheels basis, add about 5 to 15 percent more GHG than the average barrel consumed in the United States. This places them within the general range of crude oils consumed in the United States. Productive dialogue also means clarifying the other environmental and social issues, from tailings to the pace of economic development, and identifying solutions. Our study highlights the important role for government-supported research and development (R&D) to address the environmental challenges. Also important is recognizing the range of uncertainty and timing about future economic growth, oil prices, regulation, and technological advancements.

We hope that as a result of the wide participation in our study workshops by a range of organizations, combined with CERA's eight months of research, this study can contribute to finding an appropriate balance on oil sands development that meets economic and security objectives and, at the same time, safeguards the environment.

# APPENDIX A: PROJECT TEAM BIOS

## APPENDIX A: PROJECT TEAM BIOS

**Daniel Yergin, *IHS CERA Chairman – Study Chairman,*** is a highly respected authority on energy, international politics, and economics. Dr. Yergin is a recipient of the United States Energy Award for “lifelong achievements in energy and the promotion of international understanding.”

Dr. Yergin received the Pulitzer Prize for his work *The Prize: The Epic Quest for Oil, Money and Power*. The book has been translated into 17 languages and has just been released in a new updated edition.

Of Dr. Yergin’s subsequent book, *Commanding Heights: The Battle for the World Economy*, the *Wall Street Journal* said, “No one could ask for a better account of the world’s political and economic destiny since World War II.” It has been translated into 13 languages.

Dr. Yergin is writing a new book on the challenges of energy, geopolitics, and climate change.

He chaired the US Department of Energy’s Task Force on Strategic Energy Research and Development. He is a member of the Board of the United States Energy Association, and a member of the US National Petroleum Council. He recently served as Vice Chair of the new National Petroleum Council study, *Facing the Hard Truths about Energy.* He is one of the “Wise Men” of the International Gas Union.

He serves as CNBC’s Global Energy Expert.

Dr. Yergin was awarded the Medal of the President of the Republic of Italy for combining “an understanding of the dynamics of the market with a broad view of the forces of geopolitics as he seeks to point the way to the positive outcomes for the world community.”

He is a Trustee of the Brookings Institution, on the Board of the New America Foundation, and on the Advisory Board of Energy Initiative at the Massachusetts Institute of Technology and the Advisory Board of the Peterson Institute for International Economics. He is also a Member of the Singapore International Advisory Panel on Energy.

Dr. Yergin holds a BA from Yale University and a PhD from Cambridge University, where he was a Marshall Scholar.

Dr. Yergin cofounded IHS Cambridge Energy Research Associates. Its offices are in Cambridge, Massachusetts; Beijing; Calgary; Dubai; Houston; Mexico City; Moscow; Oslo; Paris; San Francisco; Sao Paulo; Singapore; Tokyo; and Washington, DC.

**David Hobbs, *IHS CERA Vice President and Head of Research – Study Advisor,*** is an expert in energy industry structure and strategies. He previously led CERA's research activities in oil markets and strategies, liquefied natural gas, technology, and environmental strategies.

Mr. Hobbs is an author of the major CERA studies *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures*, a comprehensive analysis of the problem of assessing reserves, and *Modernizing Oil and Gas Disclosures*. He is also a principal author of the CERA Multiclient Study *Harnessing the Storm—Investment Challenges and the Future of the Oil Value Chain* the author of the CERA Private Report *Daring to Be Disciplined: Continuous Portfolio Improvement*, and a project advisor to the CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.*

Prior to joining CERA, Mr. Hobbs had two decades of experience in the international exploration and production business. Mr. Hobbs holds a degree from Imperial College.

**James Burkhard, *Managing Director of IHS CERA's Global Oil Group – Study Director***, leads the team of CERA experts that analyze and assess upstream and downstream business conditions and strategies, including short- and long-term outlooks for global crude oil and refined products markets. Mr. Burkhard's expertise covers geopolitics, world economic conditions, and global oil demand and supply trends.

Mr. Burkhard was the project director of *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030*, the most comprehensive study that CERA has ever undertaken, encompassing the oil, gas, and electricity sectors. He was also the director of the CERA Multiclient Study *Potential versus Reality: West African Oil & Gas to 2020*, and a project advisor to the CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.* Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

**Jackie Forrest, *IHS CERA Director, Capital Costs Analysis Forum – Study Manager,*** has more than a decade's experience in the definition and economic evaluation of refining projects. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products, with a focus on oil sands. As the research lead for CERA's Capital Costs Analysis Forum—Downstream, she is responsible for analyzing global costs markets and monitoring emerging strategic trends related to downstream projects. She is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**James R. Meitl, *IHS CERA Senior Director, Business Development,*** is a senior account specialist focusing on western US regional markets and strategies. Based in Calgary, he has extensive experience in problem solving, strategy development, and market development. He holds an MPA and a BSc from the University of Kansas.

**Samantha Gross, *IHS CERA Associate Director,*** Global Oil, specializes in helping energy companies navigate the complex landscape of governments, nongovernmental organizations, shareholders, and other stakeholders when making investment decisions. Her recent contributions to CERA research include reports on peak gasoline demand in the United States, US vehicle fuel efficiency regulations, international climate change negotiations, and the increasing demands placed on international oil companies by governments in resource-rich countries. Ms. Gross was also the CERA Project Director for *Thirsty Energy: Water and Energy in the 21st Century,* produced in conjunction with the World Economic Forum. Before joining CERA she was a Senior Analyst with the Government Accountability Office, where she managed a study of the role and capability of the US Strategic Petroleum Reserve, led an analysis of US refining capacity and inventory practices, and prepared congressional testimony on electricity risk management practices, among other energy projects. 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.

**Aaron F. Brady, *IHS CERA Director,*** Global Oil, is an expert in the global oil market, including downstream price dynamics, political and regulatory influences, and economic trends. His analyses focus on the fundamentals of the North American refined product markets and on energy/environmental legislation and regulatory issues, including the role of biofuels. Mr. Brady is a regular contributor to CERA's global oil retainer research, providing market analysis on supply and demand fundamentals and key trends in the global downstream industry for both CERA's *World Refined Product Outlook* and the *World Oil Watch.* He was the lead author of the biofuels segment of CERA's Multiclient Study *Crossing the Divide: The Future of Clean Energy.* Mr. Brady holds a BA from Amherst College and an MA from Johns Hopkins School of Advanced International Studies.

**Roger J. Goodman, *IHS CERA Senior Consultant,*** is an authority on natural gas, coal, and electricity market trends. He specializes in strategy, scenario planning, technology, marketing, and business development. For nearly 15 years, Dr. Goodman was employed in a variety of senior management positions with Shell Canada Limited in strategic and scenario planning, business development, and marketing, especially in natural gas, electricity, sulfur, and liquids. He has also held senior management positions in the Canadian government in the areas of trade promotion, metals, minerals, and energy specialist and headed Canadian delegations as a technical expert at international meetings of United Nations Conference on Trade and Development, United Nations Industrial Development Organization, and the OECD. Dr. Goodman is the author of several CERA reports, including analyses of coal commoditization; power generation; fuel cells; hydrogen; Canada's Kyoto compliance strategies; and Canada's electric power and fuels sectors including nuclear, hydro, natural gas, and coalbed methane. Dr. Goodman holds a BA from Carleton University, a BSc (Honors) from the University of Wales in Cardiff, and a DPhil from Oxford.

**Tiffany A. Groode, *IHS CERA Associate Director,*** focuses on critical issues for CERA's Driving the Future: Energy for Transportation in the 21st Century Forum. Her expertise includes modeling and analyzing the environmental impacts of ethanol production by performing life-cycle uncertainty analysis as well as assessing the potential scale of bioethanol production from various biomass sources. While working at the Sloan Automotive Laboratory at the Massachusetts Institute of Technology (MIT), Dr. Groode presented her bioethanol results and conclusions to a variety of national government agencies to provide insight for policy decisions. Dr. Groode holds a BS from the University of California, Los Angeles, and an MS and PhD from MIT.

**Rob Barnett, *IHS CERA Associate Director,*** specializes in energy sector economics, environmental policy and strategy, and emissions markets. Mr. Barnett is responsible for CERA's North American emission price outlooks and regularly contributes to CERA's global retainer research by providing insight on the impact of environmental policies, interfuel competition, technology choice and environmental markets. He is the author of numerous CERA reports on topics including the US clean air rules, cost recovery for pollution control expenditures, and European emissions trading. Recently, he contributed to the environmental market analysis for CERA's Multiclient Study *Crossing the Divide: The Future of Clean Energy.* He also contributed to the CERA Multiclient Study *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030* and to *Clearing the Air: Scenarios for the Future of US Emissions Markets.* Mr. Barnett holds BS and MS degrees from Clemson University and an MA from Boston University.

**William R. Veno, *IHS CERA Director,*** Global Downstream, is an expert on crude oil and refined product markets, on refining and marketing, and on energy economics and strategy. Mr. Veno is a leader of CERA's global refining and marketing research activity, with particular expertise in North American refined product demand, the transportation sector, and refined product pricing. He contributes to CERA's quarterly *World Refined Products Outlook* and coordinated the oil demand analysis for the CERA Multiclient Study on global energy scenarios, *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030.* He directed the CERA studies *Gasoline and the American People 2007, Westward Flows and Refiners' Woes: The Growing Role of Imports in US Gasoline Supply,* and *Global Oil Trends.* He has participated in several National Petroleum Council studies, including analyses of petroleum product supply, the cleaner fuels value chain, and fuel inventory dynamics.

Previously Mr. Veno was Senior Petroleum Economist at Petróleos de Venezuela (USA) in New York, responsible for short- and long-term oil market analysis for the US and global markets, and had similar responsibilities as a Senior Analyst with Conoco and the US Department of Energy. Mr. Veno holds a BS from the University of Notre Dame, an MS from Dartmouth College, and an MS from Columbia University

**Matthew T. Palmer, *IHS CERA Associate Director,*** provides analysis of Western gas market fundamentals and is an expert on natural gas demand issues in North America. He provides oversight on analysis and forecasts for the residential, commercial, and industrial sectors of the North American gas market, and has recently examined how recent trends in weather have affected natural gas demand as well as the impact different climate normal's have upon natural gas demand forecasts. Mr. Palmer has examined the long- and short-term relationship between oil and natural gas prices in North America, including a thorough analysis of the factors that cause convergence and divergence between them. He is also a coauthor of CERA's *North American Natural Gas Watch* and of the *Monthly Gas Briefing* and has contributed to the CERA *Global Energy Watch.* Additionally, Mr. Palmer contributes to the ongoing development of the global scenarios through CERA's Global Energy Forum and also contributes to the North American Gas and Power Scenarios Forum.

Mr. Palmer holds a BS and an MS from the University of Massachusetts at Amherst.

**Jonathan M. Craig,** ***IHS CERA Associate,*** Global Oil Supply, is a specialist in global liquids production and capacity and in oil industry activity. Mr. Craig is the primary contributor to CERA's analytic application *Global Oil Capacity Outlook*, which provides CERA's view on future global liquid production capacity through a unique combination of country-level capacity outlooks, comprehensive data compilations, and an understanding of factors driving liquids capacity and production. Mr. Craig's work is also a major component of CERA's worldwide liquids capacity and E&P Trends Forum research.

Before joining CERA Mr. Craig worked for IHS Energy for over eight years, the last four as regional manager of IHS Global Exploration and Production Services, covering the northern Middle East, providing detailed information on exploration and production activity in the region. Previously he worked on exploration drilling operations in the UK North Sea. Mr. Craig holds a BSc from the University of Manchester.

**Randy J. Mikula,** ***CanmetENERGY Technology Centre – Team Leader, Extraction and Tailings,*** has more than 20 years experience in researching oil sands tailings behavior, including water chemistry and clay interactions. Projects have included pilot- and commercial-scale demonstrations of the gypsum consolidated tailings (CT) process, as well as work on carbon dioxide ($CO_2$) as a CT process aid. This research involves investigation of the fundamental chemistry of the $CO_2$–clay interaction, including CT formation mechanisms and the potential for $CO_2$ sequestration. The program of fundamental research, directed at oil sands tailings handling solutions has been a powerful combination. This has resulted in varied opportunities to discuss his work, ranging from testifying as an expert witness to public lectures on the role of nanotechnology in oil sands development ("Visioning Alberta's Future: The role of Nanotechnology in the Oil Sands Industry"). Most recently, Dr. Mikula has coordinated the scientific program around development and pilot-scale demonstration of centrifuged fluid fine tailings at Syncrude, a program that will likely grow to a commercial demonstration. Dr. Mikula has a PhD in chemistry from the University of British Columbia and BSc in chemistry from the University of Saskatchewan. He also is a Fellow of the Canadian Institute of Chemistry.

April 19, 2013

To:
Ms. Genevieve Walker
U.S. Department of State
NEPA Coordinator 2201 C Street NW
Room 2726 Washington,
D.C. 20520

Dear Ms. Walker,

Please see our comments for the Draft Supplemental Environmental Impact Statement (Draft SEIS) for the Keystone XL Project that was released on March 1, 2013.

Our comments are supported by the attached report, *Oil Sands Greenhouse Gasses, and US Oil Supply: Getting the Numbers Right – 2012 Update*[i].

Our report draws on the analysis and insight from the IHS CERA Oil Sands Dialogue. Since 2009, our Oil Sands Dialogue has brought together policymakers, industry representatives, academia, non-governmental organizations, environmental organizations, and other related stakeholders to advance the conversation surrounding Canadian oil sands development. The objective is to enhance understanding of critical factors and questions surrounding industry issues and foster a fact-based discussion.

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The Draft SEIS is a thorough investigation of the potential environmental impacts from the Keystone XL project. However, our analysis differs from the Draft SEIS in two key areas:

**Incremental greenhouse gas emissions (GHG) emissions associated with consuming oil sands are lower than that reported in the Draft SEIS.** The Draft SEIS states that oil sands life-cycle GHG emissions are 17 percent higher than the average[ii]. Our latest research shows that life-cycle GHG emissions from oil sands imported into the United States are 12 percent higher than the average crude oil consumed in the US[iii]. The Draft SEIS oil sands production and upgrading emissions are dated and outside the range of IHS CERA and other studies that represent current oil sands operations and products[iv].

**If Keystone XL is not approved, GHG emissions from substitute crudes would be in the same GHG emissions range as oil sands, not lower. The reason for this is the alternative to Canadian oil sands will be Venezuelan heavy oil.** The Draft SEIS states that if crudes from the Keystone XL were to replace crudes from other sources, that the lifecycle emissions would likely increase[v]. The US Gulf Coast refining region consumes large volumes of heavy crude oils—crudes that are similar in quality to much of the expected growth in oil sands supply. With or without oil sands supply to the Gulf Coast from Keystone XL, refiners there will continue to process heavy crude oils given the large scale of the coking capacity. Today, the largest supplier of USGC heavy

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crude is Venezuela. While lifecycle GHG emissions from oil sands imported and consumed in the United States range between 4 and 23 percent higher than the average crude oil consumed in the US (average value is 12 percent); Venezuelan crudes are in the same GHG intensity range —between 4 and 20 percent higher[vi]. If Keystone XL is not built, the United States will import more heavy oil from Venezuela; these crudes have similar carbon intensities to Canadian oil sands products (resulting in little to no change in the overall GHG intensity of the US crude slate).

Our attached report provides more analysis to support our conclusions. It cites our publicly available research that we have conducted in recent years with consultation of many stakeholders.

We appreciate your consideration of our comments.

Sincerely,

James Burkhard, Vice-President and Head of Research, Oil Markets, Energy Scenarios and Integrated Services
Jackie Forrest, Senior Director, Oil Sands Research, IHS CERA

[i] The paper's detailed appendix has also been included for reference.
[ii] Specifically, the Draft SEIS states, ES 5.5.2 (page ES-15) "WCSB crudes are more GHG-intensive than the other heavy crudes they would replace or displace in U.S. refineries, and emit an estimated 17 percent more GHGs on a life-cycle basis than the average barrel of crude oil refined in the United States in 2005."
[iii] See Table 2, page 23 IHS CERA Special Report "*Oil Sands Greenhouse Gasses, and US Oil Supply: Getting the Numbers Right – 2012 Update*", November 2012. Reported value assumes a wide boundary for measuring GHG emissions and is consistent with the 2005 average crude baseline used in the Draft SEIS. Wide boundary includes all emissions beyond the facility site including those from producing natural gas used at the oil production facilities and from electricity generated off site.
[iv] The Draft SEIS uses data from 2009 US Department of Energy National Energy Technology Laboratory DOE NETL report which estimates GHG emissions in 2005(DOE NETL, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions, March 27, 2009*). IHS CERA did not use the DOE NETL study in our analysis, since the source is dated and does not represent current operations – which have lower emissions compared with 2005 (The DOE NETL GHG emissions for oil sands extraction and upgrading are about 1.5 times higher than the IHS CERA and others study results of current operations). Also, DOE NETL estimate does not account for how bitumen products are actually shipped to the US market for refining – as a blend of bitumen and lighter diluents:
**Mining and Upgrading SCO.** About half of today's oil sands production is from mining and upgrading. DOE NETL 2009 assumes a 2005 mining and upgrading emission value of 134 kilograms of CO2 (kgCO2) per barrel of SCO or about 120 (kgCO2 per barrel of refined products. The source for this value is not clear. The DOE NETL values are higher than those of any studies used in the IHS CERA analysis (which looked at the range of results across eight sources for mining and upgrading published since 2010). The range of results for the sources studied by IHS CERA was 87.5 to 103 kgCO2 per barrel of refined products, and the average value was 92 kgCO2 per barrel of refined products (see IHS CERA detailed Appendix A1-9 for data).
**Thermal extraction emissions.** Thermal methods inject steam into the wellbore to heat up the bitumen and allow it to flow to the surface. Two thermal processes are in wide use in the oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). On average SAGD has lower GHG emissions per barrel produced than CSS. In 2012 about 65 percent of oil sands produced from thermal extraction were from the SAGD method, and SAGD volumes are growing. To estimate GHG emissions for producing dilbit with thermal extraction, the DOE NETL study draws on a 2005 value for producing bitumen using the relatively high-emission CSS method (a process that represents 35 percent of current production) and assumes 134 kgCO2 per barrel. In the case of thermal production, there is no source for the estimate used in the DOE NETL 2009 paper; however, in a previous paper published in 2008 DOE NETL does provide a source for this value (a 2006 estimate for CCS Imperial to produce a barrel of bitumen). In addition, the estimate assumes the production of a barrel of bitumen only, a product that cannot be transported via pipeline. IHS CERA assumes that dilbit, not bitumen, will be shipped down the pipeline and ultimately converted into refined products on the US Gulf Coast. The IHS CERA analysis (which looked at the range of results across 8 sources published since 2010), found that thermal extraction of dilbit produced between 43 and 109 kgCO2 per barrel of refined products, and the average value (assuming 65% dilbit from SAGD and the reminder from CCS) was 80 kgCO2 per barrel of refined products (see detailed Appendix A1-9 for data).
[v] [v] Specifically, the Draft SEIS states, ES 5.5.2 (page ES-15) "As WCSB and Bakken crudes replace crudes from other sources—independent of whether the proposed Project exists—the life-

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cycle GHG emissions associated with transportation fuels produced in U.S. refineries would likely increase"

[vi] See Table 2, page 23 IHS CERA Special Report "*Oil Sands Greenhouse Gasses, and US Oil Supply: Getting the Numbers Right – 2012 Update*", November 2012. Reported values all assume a wide boundary for measuring GHG emissions and are consistent with the 2005 average crude baseline used in the Draft SEIS. Wide boundary includes all emissions beyond the facility site including those from producing natural gas used at the oil production facilities and from electricity generated off site.

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# All aboard: A view of Alberta curtailment

May 2019

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Canadian Oil Sands Dialogue | **Strategic Report**

# Contents

# All aboard: A view of Alberta curtailment

## Key implications

Since the Government of Alberta announced that it would curtail output for 2019, the guidance and monthly curtailment volumes have evolved, and the timing of the Enbridge Line 3 Replacement project (previously expected in late 2019) was delayed by a year. This report provides a view on the key supply and demand developments in the western Canadian market and an assessment of their impact.

- **Since curtailment was announced, western Canadian crude price differentials have narrowed to a level much tighter than averaged in 2018.** Since curtailment was announced, the heavy oil differential between Western Canadian Select (WCS) at Hardisty and WTI at Cushing has averaged about $12/bbl. Mixed Sweet Blend (conventional light oil) has averaged less than $5/bbl beneath WTI, while Synthetic Crude Oil has averaged just over $1/bbl beneath WTI. This result compares with $27/bbl, $12/bbl, and $7/bbl beneath WTI in 2018, respectively.

- **IHS Markit expectations for Alberta production have increased over 2019 as Alberta has moderated curtailment and as publicly available information has increased.** We currently expect 2019 Alberta production to average 3.4 MMb/d, which is about 300,000 b/d less than our precurtailment outlook but certainly a more optimistic view of the potential level of Alberta output that would result in a much larger estimate of the scale of reduction. With a few exceptions, western Canadian supply available for export is generally exceeding pipeline takeaway capacity even with the completion of Enbridge Line 3 until additional pipeline can be brought online—the latter likely sometime in 2022.

- **The delay of Enbridge Line 3 increases the importance and the call on rail.** The estimated call on rail is highly sensitive to the productivity of oil production facilities and the state of provincial curtailment policy, which is currently less certain given the recent change in government in Alberta. Based on what we know today, owing to the delay of Line 3 to late 2020, the call on rail could crest over the winter of 2019/20 between 400,000 b/d and 500,000 b/d, which is typically the high point of western Canadian output.

- **Crude by rail remains critical for ensuring western Canadian crude market access and avoiding the extreme upstream price discounts of late 2018.** IHS Markit estimates that crude-by-rail capacity should exceed 500,000 b/d in late 2019—roughly capable of meeting anticipated demand. However, this estimate includes some rail capacity that was idled in early 2019 because of narrower price differentials. There is risk that should some of this capacity face delays in ramp-up, there may be little room in the market to absorb any takeaway upsets.

—May 2019

# All aboard: A view of Alberta curtailment

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## About this report

**Purpose.** As supply overtook available pipeline takeaway capacity in 2018, western Canadian crude oil price differentials widened—a lot—and prices collapsed to record lows. As a result, the Government of Alberta made the extraordinary decision in late 2018 to impose mandatory production limits for Alberta crude oil production in 2019. This report provides a brief overview of curtailment, the impact on the western Canadian oil market, and the implications of the additional delay in the Enbridge Line 3 Replacement project.

**Context.** Since 2009, IHS Markit has provided research on issues surrounding the development of the Canadian oil sands. This report is part of a series of reports from the IHS Markit Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

**Structure.** This report has five sections.

1. How did western Canada get here?
2. Western Canadian 2019 production in curtailment
3. An evolving production outlook
4. Curtailment impact on prices
5. The question of adequacy of rail capacity

## How did western Canada get here?

Price volatility was the defining story of the Western Canadian Sedimentary Basin in 2018. As pipelines that were proposed to increase western Canadian takeaway capacity were delayed, it became increasingly clear that oil supply would eventually overtake available pipeline export capacity and railroads would be required to move increasing volumes of western Canadian crude oil to market. However, what may not have been fully appreciated was that it would take time to bring online the required rail capacity, and thus capacity might lag demand. The result: extreme price volatility.

As new projects continued to ramp up over the course of 2018, pressure built on the western Canadian takeaway system. At times, some producers were unable to move crude to market. When differentials were at their widest, Western Canadian Select (WCS) at Hardisty—the principal western Canadian heavy oil benchmark—traded down as much as $50/bbl beneath WTI at Cushing. These extreme differentials, coupled with weakening global prices on the back half of 2018, caused the price of WCS in Alberta to reach lows of $14/bbl—worse than during the nadir of the global oil price collapse in early 2016. Although WCS was the most extreme example, all crude grades were impacted. Key light benchmarks such as Mixed Sweet Blend (MSW) and Synthetic Crude Oil (SCO), in Alberta traded $36/bbl and $33/bbl below WTI, respectively, at their widest, with absolute prices falling to nearly $20/bbl and $25/bbl, respectively, at their lowest.

Faced with a large reduction in the value of oil in western Canada, from which the province collects royalties, and the prospect that if the extreme differentials persisted, some smaller producers may have struggled to remain solvent, the Government of Alberta made the extraordinary decision to intervene in the market and limit production in 2019. On 2 December 2018, the government announced it would put in place mandatory production limits on individual operators in Alberta. Alberta is the largest oil-producing region in Canada; in December 2018, it was producing about 3.5 MMb/d—80% of western Canadian production.

The impact on western Canadian prices following the curtailment announcement was almost immediate. To be certain, differentials had already been narrowing as US Midwest refining turnarounds were subsiding and potentially being aided by voluntary production restraint within the market and anticipation that the government may intervene.[1, 2] However, there is no way to be certain how long it may have taken for differentials to mount a full recovery absent the curtailment mandate. The WCS-WTI differential dropped from a peak of $50/bbl in mid-October to $29/bbl just prior to the curtailment announcement on 2 December 2018. By the end of the trading day on 3 December, the differential narrowed to $22/bbl and two weeks later to $17/bbl. The differentials for lighter grades like MSW and SCO also narrowed from $23/bbl and $20/bbl, respectively, just prior to the announcement to $7/bbl and $3/bbl, respectively.

## Western Canadian 2019 production in curtailment

Since curtailment was announced, the rules and curtailment volumes have evolved. In total, the Government of Alberta has made seven separate changes since 2 December 2018. Some were minor tweaks that appear aimed at increasing the equitability and/or flexibility for individual operators. Others were more material, such as how curtailment was being calculated and assessed for each operator, as well as changes in the amount of monthly curtailment.

Estimating curtailed production and allocation volumes is not straightforward, and, coupled with the ongoing changes and monthly allocations, there have been differences of opinion over the degree of curtailment and associated reductions. It has also become increasingly difficult to consistently forecast production since output is being dictated by the government with only one or two months' notice. Based on what has been announced to date, curtailment has reduced our expectation for western Canadian supply available for export in 2019 by more than 125,000 b/d, with the greatest impact felt by heavy, sour crudes.[3] However, the expected reduction from a precurtailment outlook depends on how curtailment unfolds (the degree of future curtailment) over the course of the year and on the level of production that could have been achieved in the absence of curtailment. A more optimistic view on the depth and breadth of downtime associated with seasonal oil sands maintenance; the expected utilization rate of key oil sands operations such as Syncrude, which showed nearly

1. Dan Healing, "Cenovus Makes Oilsands Cuts to Avoid Low Prices, 'Not for Charity,' Says CEO," Financial Post, 31 October 2018, https://business.financialpost.com/pmn/business-pmn/cenovus-reports-241-million-third-quarter-loss-lowers-capex-guidance, retrieved 24 April 2019; "Alberta Energy Firms Split on Call for Government-Imposed Production Cuts," CBC, 16 November 2018, https://www.cbc.ca/news/canada/calgary/production-oil-cuts-government-companies-husky-cenovus-suncor-price-differential-1.4909036, retrieved 24 April 2019.

2. US Midwest refinery turnarounds in the fall of 2018 were some of the deepest in the past three years. At its peak, nearly 1 MMb/d of capacity (and, as a result, demand) was offline.

3. Western Canadian supply available for export is western Canadian production, plus imported blending requirements, less regional refinery demand.

record levels of output prior to curtailment; or even the potential ramp-up of a new facility such as Cenovus's Christina Lake expansion could all result in a greater expectation of production in the absence of curtailment and thus a greater estimate of the degree of supply constraint. For more information on how to estimate curtailed production allocation volumes, see the box "How to estimate curtailment."

## An evolving production outlook

Expectations for the 2019 Alberta production outlook have evolved along with changes to curtailment rules, progressive announcements of monthly allowances, and shifting expectations of the timing of the Enbridge Line 3 Replacement project. Currently, IHS Markit expects Alberta production to average 3.4 MMb/d in 2019, down from our precurtailment outlook of about 3.8 MMb/d.

Since curtailment was first announced, there have been three distinct changes to the rules, one of which had a material impact on the curtailment volumes for most operators. This rule change based the operator's curtailment off the maximum production month between November 2017 and October 2018, rather than the average of the top six months during that time frame. This rule change significantly increased allowable production for some operators that had projects in ramp-up during that time or had achieved above-average results in at least one month. The other two rule changes were aimed at more equitably distributing the curtailment between operators, particularly operators with projects in ramp-up.

Monthly curtailment volumes have also been modified over the year. At the onset of curtailment, the government had stated that monthly curtailment volume over first quarter 2019 would average 325,000 b/d and curtailment would step down to average 95,000 b/d for the remainder of the year. To date, the government has announced 325,000 b/d for January, 250,000 b/d for February and March, 225,000 b/d for April, 200,000 b/d for May, and 175,000 b/d for June. These changes have been a source of uncertainty for anticipated western Canadian output. Moreover, with monthly curtailment volumes announced for April to June in excess of 95,000 b/d, should the government wish to achieve its prior target of an average of 95,000 b/d from April to December, a lower level of curtailment will be required during July–December (for which the monthly curtailment volumes are yet to be announced). For the balances in this report, IHS Markit assumed a monthly curtailment volume of 95,000 b/d for the remainder of the year. The recent election of a new government in Alberta, which could change the direction of policy, is another source of complexity in the outlook.

Another source of shifting expectations has been over the timing of the Enbridge Line 3 Replacement project. The Line 3 Replacement project represents potentially the earliest new incremental pipeline capacity that could be brought online. The Line 3 Replacement project will replace an existing pipeline that runs from Hardisty, Alberta, to Superior, Wisconsin, which has been running at reduced capacity. This project will restore capacity to 760,000 b/d and result in an incremental takeaway uplift for western Canadian producers of about 370,000 b/d.

For many, the timing of Enbridge Line 3 was a potential pivot point in curtailment, with the additional capacity greatly increasing western Canadian takeaway. Early in the IHS Markit outlook, we had anticipated a need to remove or significantly weaken curtailment with the onset of Enbridge Line 3 operations. As recently as late 2018, Enbridge had indicated that Line 3 was expected online in late 2019; however, in early 2019 it was announced that the in-service date was delayed until second half 2020.[4]

As a result of the delay of Line 3, the likelihood that curtailment would remain in place to the end of 2019 increased. Production growth in 2020 may also be affected as upstream operators could decide to slow the

4. Please see "State of Minnesota Provides Permitting Timeline for Line 3 Replacement Project," Enbridge, 1 March 2019, https://www.enbridge.com/media-center/news/details?id=123564&lang=en, retrieved 12 March 2019.

## How to estimate curtailment

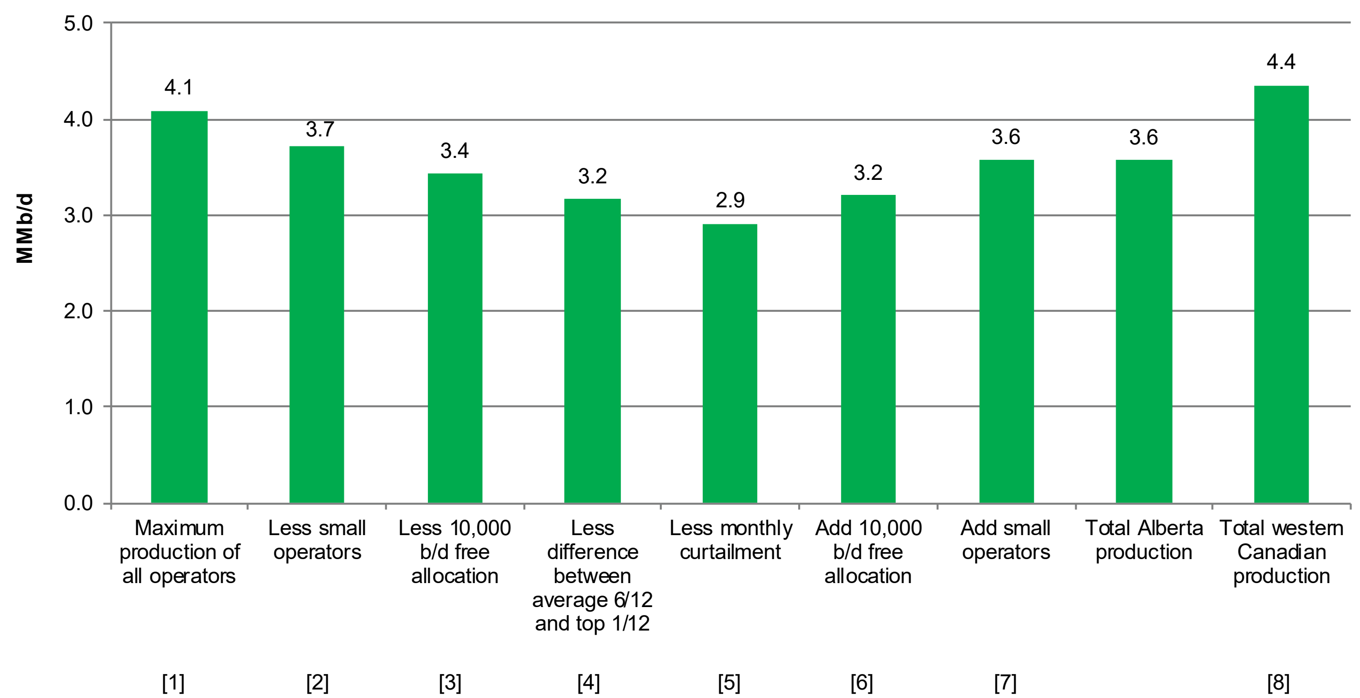
Estimating curtailed production allocation volumes is not straightforward. There are numerous steps in the calculation, and the order of these steps can impact the results. On 8 February 2019, the Government of Alberta released a presentation that better clarified the curtailment method as well as production volumes for each of the calculations.* This box outlines how curtailment is calculated using February 2019 average production and curtailment volumes as an example.

The first part of the calculation involves establishing the baseline, or maximum production of all operators, as denoted in Figure 1 by "[1]." The baseline is not the current, past, or forecast production but rather a calculation based on historical production for each operator producing light, heavy, and bitumen crude oil (pentane plus [including condensate], NGL, and natural gas production are exempt). The peak month for each operator from November 2017 to October 2018 is summed to attain the baseline. IHS Markit estimates the baseline to be 4.1 MMb/d.

From this baseline, the small operators that produce less than 10,000 b/d are removed, bringing the volume down to 3.7 MMb/d, as denoted by "[2]" in Figure 1. The volume is then further reduced by the 10,000 b/d that is free for operators that produce more than 10,000 b/d (large operators). IHS Markit estimates that 28 operators in Alberta produce more than 10,000 b/d. This result brings the volume down to 3.4 MMb/d (note [3] in Figure 1) and is referred to by the Government of Alberta as the adjusted baseline.

Figure 1

**Government of Alberta production allocation calculation for February 2019**




Source: IHS Markit



*Government of Alberta: "Curtailment Rules Under Responsible Energy Development Act," https://www.energy.alberta.ca/AU/History/Documents/CurtailmentRulesUnderREDAWebinar.pdf, retrieved 8 February 2019.

### How to estimate curtailment (continued)

The adjusted baseline is further reduced by a difference established between the six-month average calculation and the top month calculation. IHS Markit believes this adjustment is the result of attempting to adjust for the difference in aggregate output that would result between the two calculation methods.** IHS Markit assumes the six-month average calculation to be the average of the top six months from November 2017 to October 2018 for total Alberta crude oil (excluding condensates). The top month calculation is attained similarly; however, it is only the peak month during this time frame. This reduction brings the adjusted baseline down to 3.2 MMb/d, as denoted by "[4]" in Figure 1.

Lastly, the adjusted baseline is further reduced by the announced curtailment volume for the month. For first quarter 2019, the announced curtailment volumes equaled 325,000 b/d for January and 250,000 b/d for February and March. This amount results in what the government is calling the combined provincial production allocation, which IHS Markit estimates to be 2.9 MMb/d, noted by "[5]" in Figure 1.

The production allocation for each large operator is calculated by dividing the combined provincial production allocation by the adjusted baseline, estimated to be 85% for February and March 2019. This result indicates that large operators are allowed to produce up to 85% of their peak month's production plus the 10,000 b/d free.

Total Alberta production can be reached by adding back the 10,000 b/d free for the large operators and the production of the small operators to the 2.9 MMb/d combined provincial production allocation, denoted in "[6]" and "[7]" in Figure 1. IHS Markit estimates total Alberta production in first quarter 2019 to be 3.6 MMb/d.

To understand western Canadian supply and demand (adequacy of takeaway), total Alberta crude oil production must be added to condensate supply from Alberta, as well as British Columbia, Saskatchewan, and Manitoba crude oil production, as noted in "[8]" in Figure 1, since all western Canadian crude competes for the same pipeline space. IHS Markit estimates total western Canadian production to be 4.4 MMb/d in first quarter 2019.

**This adjustment is noted by the box with red writing on slide 8 of the presentation by the Government of Alberta: "Curtailment Rules Under Responsible Energy Development Act," https://www.energy.alberta.ca/AU/History/Documents/CurtailmentRulesUnderREDAWebinar.pdf, retrieved 8 February 2019.

ramp-up of recently or soon-to-be completed projects to coincide with the revised timing of Line 3. Moreover, during the recent Alberta election campaign, the party that will now form the government indicated that the delay of Line 3 could impact the timing for the end of curtailment.[5]

## Curtailment impact on prices

It can be argued that Alberta's production curtailment has been successful in reducing the extreme price discounts and volatility of 2018. However, curtailment remains a stopgap measure, and the underlying structural issue that led to it being invoked in the first place—the adequacy of takeaway capacity— remains. The recent delay of Line 3 underscores this point.

An unintended consequence of curtailment has been a narrowing of the price differential between western Canada and key export markets such as the US Gulf Coast to a level that has been insufficient to cover the higher cost of incremental rail transportation. IHS Markit estimates that when western Canadian heavy crude oil can clear the market by pipeline, the price difference between WCS at Hardisty and WTI at Cushing

5. Chris Varcoe, "Varcoe: Line 3 Delay Will Keep Oilpatch Spending Stagnant," Calgary Herald, 7 March 2019, http://calgaryherald.com/business/energy/varcoe-line-3-delay-will-keep-oilpatch-spending-stagnant, retrieved 22 April 2019.

should be $14–16/bbl (or slightly narrower in a tight heavy market, as has been the case recently), reflecting transportation costs and quality differences between the two crudes.

The most efficient form of rail transport—a dedicated train of roughly 100 crude tank cars known as a unit train—should result in a difference in price of $17–19/bbl (or potentially narrower depending on the type of crude, individual producer situation, and, in the case of heavy oil, a tight heavy oil market). Since early December 2018, the differential between WCS and WTI has averaged just $11/bbl—which is even better than what would be expected by pipeline economics.

To be fair, recently WTI has been afflicted with its own bottlenecks and constraints and has traded down from global benchmarks. An alternative comparison, with less noise, can be made between WCS at Hardisty and WCS in Houston, tracked by Argus Media. Over first quarter 2019, the WCS, Hardisty–WCS, Houston differential has averaged $13/bbl. This result is more than would be indicated by pipeline, which we estimate should cost $9–11/bbl between these markets, but less than what would typically be expected for rail, which we believe is in excess of $15/bbl.[6]

Nevertheless, as a result of the narrower differential, some producers opted to turn down their rail capacity early in the year that had been ramping up over 2018, creating concern over the adequacy of future rail capacity.[7]

Other producers indicated they have been able to break even moving crude oil by rail, and recently some operators that had turned down their rail capacity have announced the restart of the ramp-up of movements owing to improving transportation economics.[8]

The adequacy of rail capacity, which includes the time it can take to ramp up rail capacity, is a concern, since demand for crude-by-rail is anticipated to build over 2019 should curtailment ease and production rise into 2020 and beyond. Even with the completion of the Enbridge Line 3 Replacement project, this extra pipeline capacity is not expected to be sufficient on its own to absorb all of western Canada's potential production. In the interim, rail will remain critical to ensure that western Canadian output is able to get to market. IHS Markit believes this situation will persist until additional pipeline capacity can be brought online. Currently, Keystone XL and Trans Mountain Expansion are trending toward start dates in late 2021 and in 2022, respectively, although Keystone XL is increasingly looking like it may be delayed to 2022. However, should either of these projects be delayed further, the importance and call on rail will only increase. Irrespective of these pipelines, IHS Markit sees an extended use of rail as some operators have invested in significant rail capacity, which can be used to reach remote refineries unconnected by pipeline or take advantage of arbitrage opportunities that may emerge from time to time.

It is unlikely that the Government of Alberta intended for differentials to narrow quite as dramatically and affect the ramp-up of western crude-by-rail capacity. The government's stated aim was to reduce price volatility, narrow the differentials, and draw down storage.[9] We believe the government sought to narrow the differentials from levels in excess of $40/bbl while keeping them sufficiently wide to support crude-by-rail. To achieve this

6. It should be noted that rail companies have sought out longer-term contracts from oil producers to ship crude by rail. These contracts can result in both a fixed and variable cost in moving crude by rail. As a result of the fixed cost component, which the shipper must pay regardless if it moves oil or not by rail, the resulting price differential to cover or justify the movement of crude by rail is lower for existing capacity than would be required to justify new incremental capacity.

7. Please see Kyle Bakx, "Falling Oil-by-Rail Shipments Could Hurt Alberta's Plan to Clear Backlog," CBC, 7 February 2019, https://www.cbc.ca/news/business/ crude- by-rail-oilpatch-imc-suncor-cn-cp-1.5007949, retrieved 12 March 2019.

8. Please see Rod Nickel and Devika Krishna Kumar, "Cenovus Pressing Ahead with Aggressive Plans to Move Crude by Rail, Fearing Full Pipelines," The Globe and Mail, 21 February 2019, https://www.theglobeandmail.com/business/industry-news/energy-and-resources/article-cenovus-energy-pressing-ahead-with-aggressive-plans-to-move-crude-by//, retrieved 12 March 2019. Please see Nia Williams, "Canada's Imperial Oil Resumes Shipping Crude by Rail," Reuters, 26 March 2019, https://ca.reuters.com/article/businessNews/idCAKCN1R72R0-OCABS, retrieved 27 March 2019.

9. "Oil production limit," https://www.alberta.ca/protecting-value-resources.aspx, Government of Alberta, retrieved 24 April 2019.

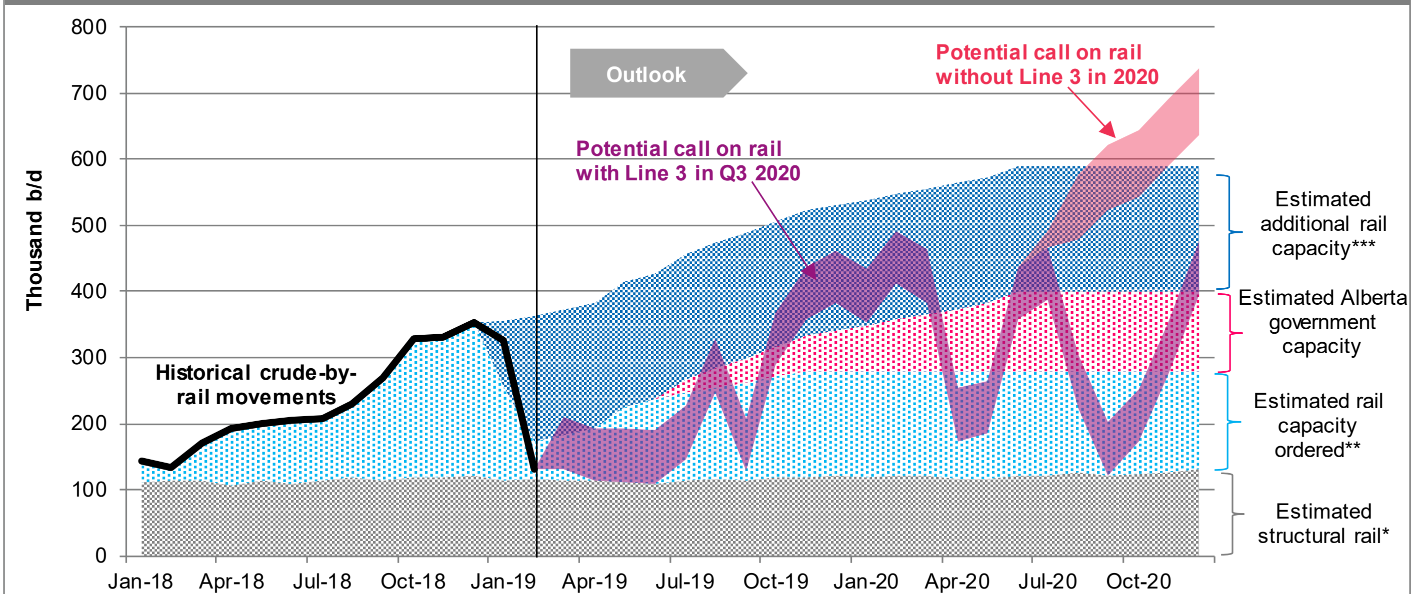
outcome, the government aimed to guide western Canadian export supply to a level that was above pipeline takeaway capacity but below available crude-by-rail capacity and thereby attempt to also draw down inventories. However, the data precision required to accurately achieve this balancing act on a 4.0 MMb/d system may simply not be achievable. Western Canadian production data typically lag two to three months, and the entire system is dynamic: production ebbs and flows, as do pipeline operations, which can impact throughput.

Moreover, the width or margin of error in placing western Canadian supply to achieve the Alberta government objectives is exceedingly narrow. At the time of curtailment, the estimated difference between total pipeline capacity and total estimated rail capacity was about 300,000–350,000 b/d. Moreover, we believe there is approximately 120,000 b/d of crude-by-rail that may be "structural," meaning production volumes that are tied to long-term rail contracts predating the current situation and thus do not compete for pipeline capacity. As a result, the price-setting fairway between pipeline and crude-by-rail may be even narrower—potentially between 160,000 b/d and 230,000 b/d. On a system of about 4.0 MMb/d, this result amounts to a margin of error of 4–5%. Since curtailment was announced, Alberta has been gradually easing limitations, appearing to try to increase supply to push differentials out toward a price difference more supportive of the economics of western Canadian crude-by-rail exports.

Looking at Figure 2, which takes into account both structural rail and potential error, it appears that the call-on-rail may be reduced over the first half of 2019, and narrower differentials more closely associated with pipeline economics have the potential to prevail until turnarounds are complete this year (May/June). However, the duration and depth of oil sands turnarounds, western Canadian inventory levels, and the fact that Alberta is allowing trading of curtailment allowances between operations creates uncertainty in estimating supply available for export. Following the turnaround season, wider differentials more consistent with crude-by-rail should settle into place. Except for turnaround periods, we expect wider price differentials, consistent with crude-by-rail economics, to persist right up to and even after the streaming of Line 3, continuing until the next pipeline can be brought online (currently anticipated for 2022).

Figure 2

Western Canadian crude oil call on rail




Note: The call-on-rail outlook represents the physical requirement on a month-to-month basis of supply available for export in excess of pipeline takeaway capacity. *"Structural rail" is established crude-by-rail movements that predate the volatility in 2018, which IHS Markit estimates to be about 3% of total supply. **"Estimated rail capacity ordered" is based on February 2019 movements (last actual data available) and is adjusted for various producer announcements (up and down) (historical less crude-by-rail movements that are expected to be down in first quarter 2019). ***"Estimated additional rail capacity" includes the maximum of known prior and anticipated capacity (including historical peak movements by operator and not just recent announcements).
Source: IHS Markit

## The question of adequacy of rail capacity

Crude-by-rail remains critical for ensuring western Canadian crude oil market access and avoiding the extreme upstream price discounts in late 2018. Several producers and the Government of Alberta have invested in incremental rail capacity, which will ramp up over 2019. Figure 2 presents the estimated call on rail based on our current understanding of curtailment, including it ending on 31 December 2019 as originally announced. As shown, the call-on-rail could crest between 400,000 b/d and 500,000 b/d through late 2019 and into early 2020, corresponding with the high point in the annual production calendar as winter drilling results begin to emerge, oil sands facilities aim to operate at their best, and diluent blending rates rise to offset colder temperatures. This result may exceed our current estimate of rail capacity believed to be in ramp-up, which includes rail capacity announcements made by companies ("estimated rail capacity ordered" in Figure 2) but not rail capacity that was reduced or turned down. If the preexisting, now reduced, rail capacity is fully revived (denoted as "estimated additional rail capacity" in Figure 2), the chance of another oversupply and resulting price instability will be substantially reduced.

It is important to acknowledge the uncertainty in IHS Markit estimates of both the anticipated call-on-rail and available rail capacity. The call-on-rail shown in Figure 2 represent the physical requirement on a month-to-month basis of supply available for export in excess of pipeline takeaway capacity. The volatility of the forecast call on rail is the result of seasonality—particularly turnarounds—anticipated curtailment levels, and the timing of Enbridge Line 3 in late 2020. In reality, month-to-month changes in movements will likely be smoother as operators choose to keep their railcars moving because of firm or fixed cost commitments of crude-by-rail, inventory changes, and arbitrage opportunities that may open up. Our estimate of available rail capacity is based on company announcements. We are aware there is additional rail capacity that we are unable to quantify that is held by some midstream and energy marketing firms. As a result, available capacity may be greater than is shown. That said, most of the anticipated rail capacity is not common carrier or publicly accessible and, as a result, access is not equitably distributed across the industry. Moreover, crude-by-rail capacity does not emerge overnight, requiring time to acquire or lease tank cars, arrange upstream and downstream loading and unloading agreements, and obtain transportation capacity from the railroads. Given the potential lead time to meet the anticipated call on rail, rail capacity would likely have to already be on order to meet future demand.

The key takeaway from Figure 2 is that the balance between anticipated export supply and takeaway capacity appears tight throughout the next year to year and a half. In the absence of sufficient spare capacity, the system may be particularly vulnerable to any disturbances such as pipeline upsets or extreme weather, which can affect rail capacity. Even with the completion of Enbridge Line 3, available supply is anticipated to exceed pipeline capacity, and the need for rail will remain until additional pipeline capacity can be brought online potentially in late 2021 or in 2022. Should Line 3 be delayed further, more rail capacity, in addition to what is believed to be on order, would be necessary to support the anticipated supply outlook. Longer term, even if all pipeline projects advance as anticipated—which is a source of uncertainty in our outlook—we see a longer-term role of crude-by-rail, which includes providing an important backstop for any unplanned pipeline outages, connecting producers to more remote refiners across North America, and accessing any potential arbitrage opportunities that may open up from time to time.

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# Four years of change

## Oil sands cost and competitiveness in 2018

April 2019

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Crude Oil Markets | **Strategic Report**

# Contents

# Four years of change

## Oil sands cost and competitiveness in 2018

### Key implications

In the run-up to the oil price collapse of 2014–15, the expansion of the Canadian oil sands developed a reputation for cost escalation. More often than not, the bill for a new project came in well above the projected budget. In 2015, IHS Markit documented oil sands' history of cost inflation and the impact lower prices were having on reducing oil sands' cost structure. Four years later, this report provides a new look at the market environment and the price of oil required for the Canadian oil sands.

- **By many metrics, oil sands costs have fallen.** The cost to construct a new oil sands project may be up to one-third less than in 2014, and the cost to operate an oil sands project fell more than two-fifths from 2014 to 2018.
- **The price of oil required for an oil sands project—thermal or mining—to break even has fallen since 2014.** IHS Markit estimates the lowest-cost oil sands project—an expansion of an existing thermal operation—could break even in 2018 (putting aside the extreme volatility in late 2018) at about a WTI price of $45/bbl compared with more than $65/bbl in 2014. A mining operation without an upgrader required a WTI price approaching $100/bbl in 2014 compared with nearly $65/bbl in 2018.
- **Yet, investment in the Canadian oil sands has continued to decline.** In 2019, IHS Markit estimates new capital investment could be the lowest in 15 years at about $8 billion. This result is a significant change from levels in 2014, when investment approached $33 billion.
- **Local prices, not global prices, are contributing to uncertainty over the timing of further investments in the Canadian oil sands.** Insufficient pipeline capacity to deliver growing volumes of Canadian oil sands crude to market contributed to extreme price volatility in 2018. Western Canadian heavy oil averaged $27/bbl less than WTI in 2018, compared with $12/bbl in 2017, and ranged from as little as $11/bbl to more than $50/bbl beneath WTI.
- **A more modest oil sands growth scenario is taking shape.** From 2018 to 2030, IHS Markit expects more than 1 MMb/d of oil sands production growth. This result would put total oil sands output at about 4 MMb/d in 2030. This number equates to average annual additions of less than 100,000 b/d, compared with additions closer to 160,000 b/d over the prior decade.

—April 2019

# Four years of change

## Oil sands cost and competitiveness in 2018

**Kevin Birn,** Vice President

### About this report

**Purpose.** In the years preceding the oil price collapse of 2014–15, the Canadian oil sands developed a reputation for cost escalation. More often than not, the bill for a new project came in well above budgeted cost. In 2015, IHS Markit documented the oil sands' history of cost inflation and the impact lower prices were having on reducing oil sands cost structure. Four years later, this report takes stock of the current state of oil sands costs. How have they changed? Why? What are the competitive implications?

**Context.** Since 2009, IHS Markit has provided research on issues surrounding the development of the Canadian oil sands. This report is part of a series of reports from the IHS Markit Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

**Structure.** This report has six sections.

- Introduction
- Costs are down
- The price of oil required to break even is down
- Local, not global, oil prices holding back the oil sands
- An uncertain investment climate
- A more modest oil sands growth scenario emerging

## Introduction

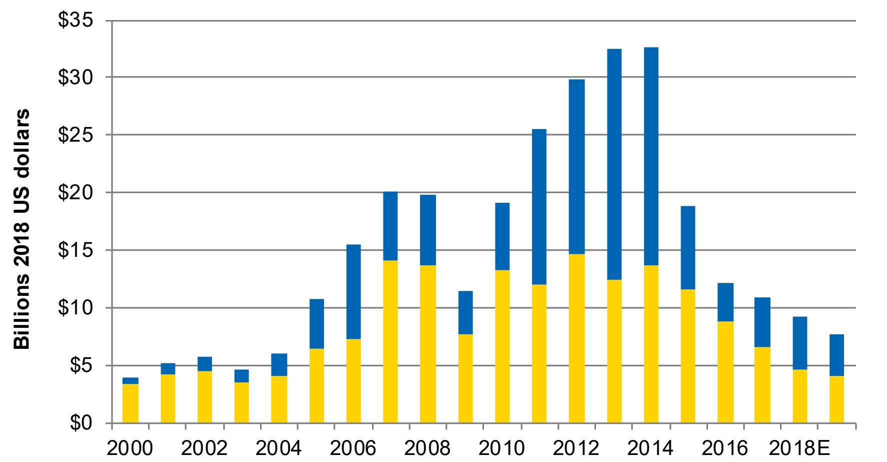
Although the global oil market remains volatile, there is a general sense that the worst of the low oil prices of recent years may be in the rearview mirror. Indeed, 2018 was marked by both a bull and bear market. Brent prices reached highs above $80/bbl and lows approaching $50/bbl. However, this was still an improvement compared with the sub-$30/bbl during the first quarter of 2016.

Although volatile, higher oil prices on average have allowed oil companies globally to begin to rebuild their balance sheets and resulted in an uptick in new investments in oil production.

Western Canada's oil sands, however, has seen investment continue to trend down. Since the 2014–15 oil price collapse began, most of the large oil sands projects in construction have been completed. Relatively higher oil prices in 2017 and 2018 encouraged the restart of the construction of projects deferred during the worst of the low prices. Operators have also advanced new capital efficiency initiatives aimed at improving reliability and output from existing operations. These initiatives include debottlenecking projects and investing in projects where excess capacity exists, utilizing that capacity to achieve higher output. All signs continue to point to a further deceleration in growth. In fact, investment in 2019 is expected to be the lowest in 15 years (see Figure 1).

Figure 1

Oil sands capital investment




Note: E = estimate.
Source: IHS Markit, Canadian Association of Petroleum Producers, Statistics Canada © 2019 IHS Markit

For detractors of the Canadian oil sands, this decline in investment confirms a view that the industry is too costly to compete. However, this view ignores the ongoing cost changes and the impact of the incredible price volatility, exceeding or in addition to global price instability, that has taken place in western Canada.

In many respects, concerns over oil sands costs are based on a historical reputation for being "high cost"—a by-product of rapid investment that preceded the oil price collapse of 2014–15. At the end of 2015, IHS Markit took stock of the efficiency gains the industry had made. We found that the industry had lowered costs, with the potential for more reductions. Indeed, when that report was issued the oil sands had yet to endure the worst of the low prices felt over the first half of 2016 (and more recently in late 2018). Through this period, the industry has continued to scrutinize existing operations and future projects for savings and adapt to a lower price environment.

This report revisits the prior report, "Oil Sands Cost and Competitiveness," released in December 2015. Now four years since 2014, how have costs changed? What does it now cost a project to produce, and what oil price is needed for a new project to break even?

Some of our methodology has changed slightly since that prior report, and subtle differences in our assessment between those years may exist. Throughout this report, we refer to various oil sands terms. See the box "Canadian oil sands primer" for definitions.

## Costs are down

Since 2014, IHS Markit has tracked significant cost reductions in the Canadian oil sands. Two key components of oil sands production costs are the capital cost and operating cost.

Capital cost represents the up-front cost to develop, construct, or bring online a new facility. Capital cost is significant for an oil sands operation: it can range into the multiple billions of dollars, and for some of the largest mining operations, into tens of billions.

## 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 166 billion bbl, making it 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 crude oil with high viscosity. Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with light oil or converted into a synthetic light crude oil. Different grades of crude oil are produced from bitumen.

**Bitumen blends.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. A common bitumen blend is dilbit—short for diluted bitumen—typically about 70% bitumen and 30% lighter hydrocarbons.

**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.

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

**Mining.** About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process, similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed and stockpiled for later use in reclamation. The layer of oil sands ore is excavated using massive shovels that scoop the material, which is then transported by truck to a processing facility. About half of production in 2018 was from mining. Mines can come with and without upgrading units.

- **Integrated mines.** The original mining operations all featured an integrated upgrader that transformed bitumen into higher-quality SCO.
- **Unintegrated mines.** The two most recently completed mining operations do not include an upgrader and, instead, market a bitumen blend.

**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 just over half of current oil sands production, and two commercial processes are used today:

- **Steam-assisted gravity drainage (SAGD).** This process has been the fastest-growing source of oil sands output and in 2018 accounted for 40% of total oil sands production.
- **Cyclic steam stimulation (CSS).** CSS was the first process used to commercially recover oil sands in situ. Growth of CSS has been outpaced by other extractive technologies, and in 2018 it accounted for less than 10% of total oil sands production.
- **Primary production.** The remaining oil sands production is referred to as primary production. Less viscous oil sands are extracted without steam using conventional oil production methods. Primary production made up nearly 4% of oil sands output in 2018.

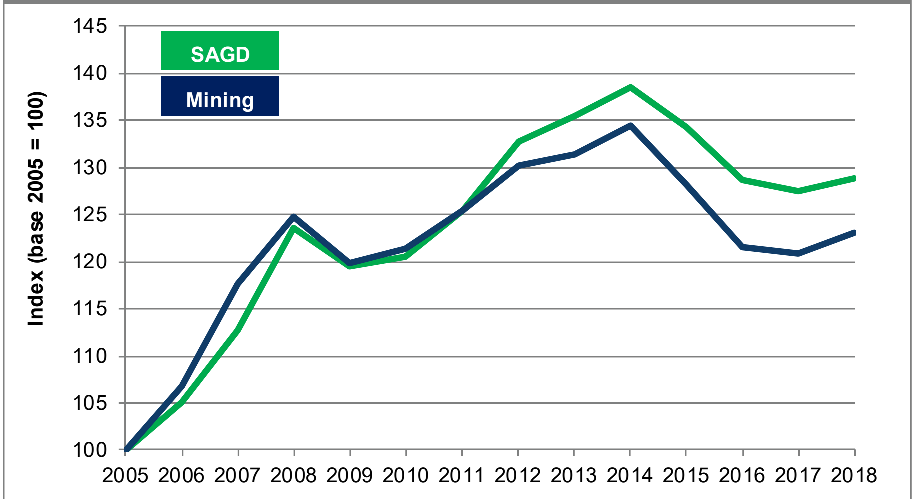
Operating cost refers to the cost to run an established plant and produce oil. Facilities that opt to upgrade bitumen into a light synthetic crude oil (SCO) will incur additional development/capital cost and operating cost than those that do not upgrade. In exchange, they sell a higher-quality and thus higher-priced crude oil. Facilities that opt to dilute bitumen with lighter hydrocarbons to permit pipeline transport will incur additional cost associated with the acquisition of the diluent. The cost of diluent is not typically reported as part of a producer's operating cost because it also has value, although generally the value received for diluent by oil sands companies from end-use refiners is less than the acquisition cost.

## Capital costs have continued to fall

Since 2014, the cost to construct a new oil sands project has come down. IHS Markit tracks the cost of the individual components that underpin the construction cost of an oil sands facility—capturing the pure inflationary or deflationary changes in oil sands construction cost over time (i.e., the change in cost to construct the same operation over time). From 2014 to 2018, IHS Markit estimates that the oil sands capital cost deflated, on average, by 10%. While this result may not seem significant, considering the scale of oil sands projects—which can average more than $1 billion—it represents a savings of at least $100 million. See Figure 2 for a complete history of oil sands capital cost inflation/deflation.

Figure 2

Oil sands capital cost index (inflation)




Source: IHS Markit © 2019 IHS Markit

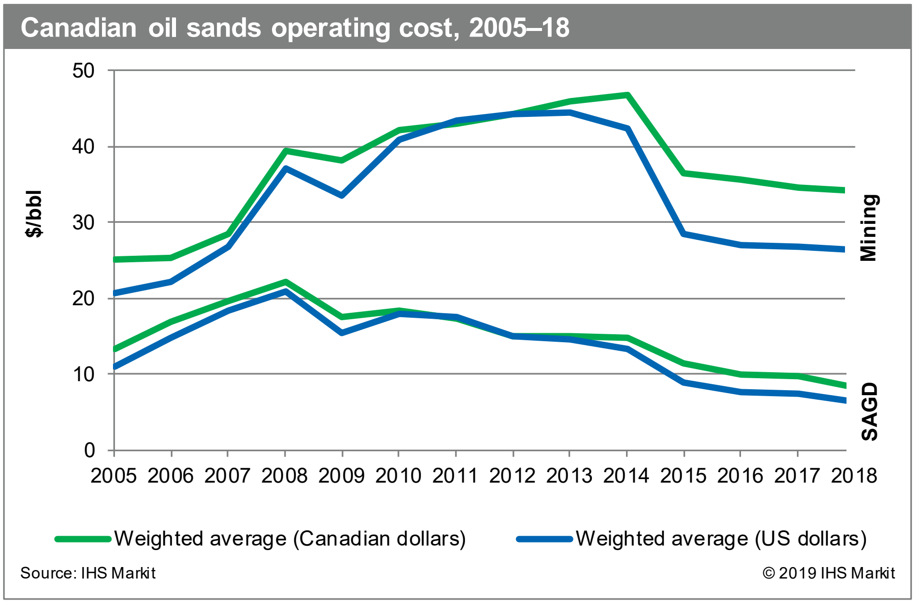
However, no one would build the same project today that would have been built in 2014. Over the past four years, producers and service providers have been working to reengineer and redesign operations. They have focused on simplifying project designs, building for less, constructing more quickly, and ramping up production faster. In addition to the cost deflation shown in Figure 2, recent announcements by oil sands producers indicate that reengineering may have resulted in an additional savings of 20–25% for new SAGD projects (the dominant source of growth in the IHS Markit outlook). Taken together—reengineering and cost deflation—the cost of a new oil sands project may be anywhere from 25% to a full third cheaper than in 2014.[1]

## Operating costs have nearly been cut in half

Operating costs fell more dramatically than capital cost (see Figure 3). From 2014 to 2018, the operating cost for both oil sands mining operations with an upgrader and SAGD facilities fell, on average, by more than 40%. In some instances, operators were able to cut operating costs in half. In 2014, the average SAGD operating cost ranged in the mid- to high teens per barrel, whereas in 2018 it had fallen to less than $10/bbl. Some operations are achieving an operating cost approaching $5/bbl. Integrated mining operating costs averaged above $40/bbl in 2014 compared with under $30/bbl in 2018.

1. In 2014, IHS Markit assessed the typical oil sands SAGD project capital cost to be approximately $40,000–50,000 per flowing barrel, with expansions being approximately $10,000 per flowing barrel lower. Recent announcements by various operators indicate a potential capital cost range of $28,000–38,000, with expansions potentially ranging around $20,000 per flowing barrel of capacity.

Figure 3




The key drivers behind the operating cost reductions include access to more efficient labor and capital, finding ways to do more with less, and improvements in operational efficiency and project reliability. Slowing activity has allowed producers to access more efficient or productive labor and equipment. Project operators have also sought to weed out unnecessary expenses. For example, mines that used to run multiple garbage trucks may now run only one. What once was thought important, such as an exterior light here or there at a plant, may now be deemed unnecessary. However, the largest factor appears to be a focus on reducing facility downtime and increasing throughput—in other words, increasing reliability. Oil sands operating costs have a high fixed cost component. Improvements in reliability allow more units to be produced (greater output), which lowers the cost on a per unit basis. These improvements also have positive implications for the greenhouse gas (GHG) emission intensity, which has fallen 10% since 2014.[2]

## The resilience of cost reductions

Looking at key measures of cost deflation—operating and capital cost, shown in Figures 2 and 3—it is apparent deflation may be in the trough. This situation raises questions about the potential for further reductions or how resilient current savings may be. This subsection discusses the outlook for oil sands cost.

Although Figures 2 and 3 point to slowing cost reductions, with overall western Canadian upstream activity trapped by both government production limits and available transportation capacity, a rapid rise in inflation is unlikely in the immediate term. Looking beyond current constraints, there are inflationary risks to the oil sands cost structure. These risks include the capacity of the remaining western Canadian service sector, which has contracted since 2014, as well as the potential for increased competition for services and skilled labor from emerging western Canadian unconventional plays, associated petrochemical and midstream infrastructure build-out, and advancing west coast LNG export projects.

However, it is important to make a distinction between inflation- or deflation-driven cost changes—increases or decreases in the cost of key inputs—versus changes that are the result of structural changes, such as how projects are designed, constructed, and operated. Structural changes tend to be more permanent.

IHS Markit analysis indicates that the largest share of oil sands capital cost reductions can be attributed to structural changes. For example, of the capital cost reductions we have tracked for SAGD, we estimate two-thirds to three-quarters of savings may be associated with reengineering and design changes. This result may mean oil sands costs have greater potential to remain in check even should inflationary pressures resume. There are also new technologies being piloted that have the potential to deliver even greater capital savings.

2. For more information on oil sands GHG intensity, see the IHS Markit Strategic Report *Greenhouse gas intensity of oil sands production: Today and in the future*.

See the text box “The promise of technology: Potential future capital efficiency gains” for a discussion of potential implications of advancing steam displacement technologies.

**The promise of technology: Potential future capital efficiency gains**

Producers are advancing various forms of “steam displacement technologies” as a means to drive operating and capital costs lower (as well as GHG emission intensity). Solvent-assisted extraction is the most talked about, but producers are actively experimenting with the coinjection of methane and other noncondensable gases.

SAGD operates on two fundamental principles: the transfer of heat from steam to the bitumen to improve its mobility and pressure from the application of steam to drive the mobilized bitumen to the recovery wells (assisting gravity). Producers have learned from experience that the reservoir can hold temperature better than they earlier anticipated. This fact means they may be able to reduce the energy required over time. The challenge is that they need to maintain pressure. They are experimenting with injecting noncondensable gases, like methane, that can physically replace some of the steam required per barrel. SAGD facilities are sized to manage treatment of recovered water and the generation of steam. As the steam needed per barrel falls, producers can redeploy excess steam and produce more oil from the same capital investment—increasing capital efficiency and potentially reducing operating cost depending on the cost and recycle rate of the coinjected material.

## The price of oil required to break even is down

In part because of cost improvements, the price of oil required for a new oil sands project to cover and earn a return on investment capital has fallen. The oil price breakeven is an important metric that determines the relative attractiveness in investing in a new oil-producing asset. For our analysis, we include all the up-front capital required to bring an oil project online, the cost to operate the facility over its life, any sustaining capital required to maintain the operation, and a reasonable return on capital deployed (we used 10% for this analysis), discounted back to the present. Because oil sands operations produce both heavy and light crude, the breakevens are expressed on a WTI equivalent basis (adjusting for quality and transportation costs to allow for an apples-to-apples comparison).

All things being equal, the price of oil required to justify a new oil sands project—mining or SAGD—has fallen. As shown in Figure 4, IHS Markit estimated that the lowest-cost oil sands project—an expansion of an existing SAGD facility—required a WTI price more than $65/bbl in 2014 to break even. In 2018, this price had fallen into the mid-$40s/bbl. A mine without an upgrader required a WTI price approaching $100/bbl in 2014 compared with nearly $65/bbl in 2018.[3]

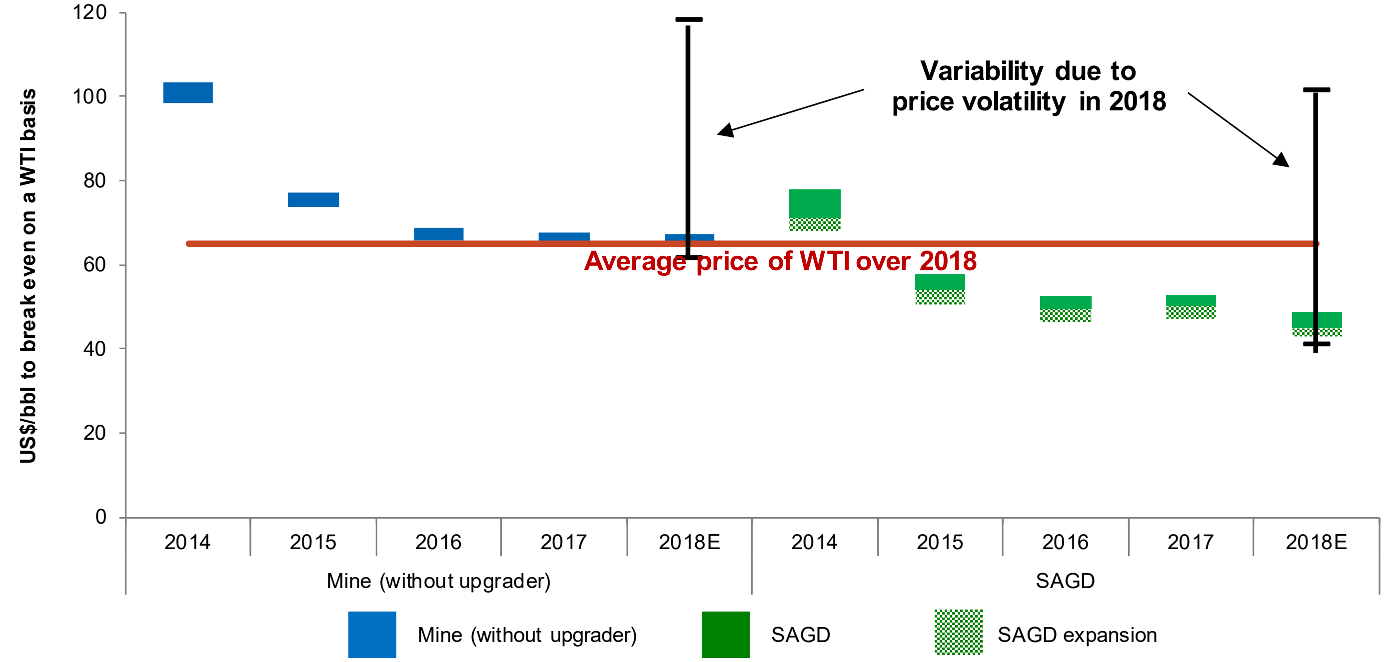
## Local, not global, prices holding back oil sands

Despite the sizable reductions in operating cost and capital cost, oil sands economics hinge on a number of market-based factors. These factors can be as important as, if not more important than, factors arguably within the producer’s control (such as operating and capital cost). These include factors like the price of natural gas used to generate heat and steam; the price of condensate used in the creation of diluted bitumen (for facilities that lack an upgrader); exchange rates that influence the cost of goods purchased in Canadian dollars while oil is sold in US dollars; and finally (and perhaps most importantly), the basis differential or difference in price between crude oil in western Canada and crude priced in the US and international markets.

3. It is important to note that these break-even estimates assume a differential between western Canada and WTI more consistent with that in 2017 (and early 2019), approximately $12/bbl between western Canadian heavy oil as tracked by Western Canadian Select (WCS) and WTI, as opposed to the extreme volatility in 2018.

Figure 4

Canadian oil sands break-even analysis, 2014–18




Source: IHS Markit



These market-based inputs are not necessarily always negative for the Canadian oil industry. Canada is a major exporter of crude oil, and during the low oil prices of the past few years, the rapid reduction in the value of oil exports contributed to a weakening in the value of the Canadian dollar. This reduction, in turn, lowered the price of goods that producers sourced domestically. Therefore, although producers were receiving a lower price for their oil, the lower cost of goods helped offset some of this impact. Additionally, the price of natural gas—an important input cost for oil sands producers—has fallen since 2014. From 2014 to 2018, the price of natural gas in western Canada has fallen more than two-thirds, from $4.00/Mcf in 2014 to about $1.20/Mcf in 2018. Additionally, the expectation is that western Canadian gas prices will likely remain beneath $3.00/Mcf for the foreseeable future. The price of condensate in western Canada typically commands a premium to light crude oil, but also tracks global benchmarks, and its value declined along with crude oil over the past few years, another benefit on the cost side for oil sands producers.

To a large extent, these market variables worked in the oil sands' favor through the worst of the low oil prices over the past few years. However, the impact of oil price differentials is a different story. A differential is the price difference of a particular crude oil relative to the price of oil in another region or globally, as typically tracked by key oil benchmarks such as WTI or Brent.

A differential typically consists of both a quality factor, which accounts for the differences in properties of various crude oil, and a transportation factor, which captures the cost to move a crude oil between markets. For an inland producer of crude oil, the narrower the differential, the lower the difference in price between regions would be, and the better it is for the producer. In western Canada, if the market is functioning smoothly and producers can move their crude to US markets via pipeline, western Canadian heavy crude oil should trend toward $14–16 beneath WTI on average—reflecting the approximate transportation and quality difference to Cushing, Oklahoma, where WTI is traded.

Through the oil price downturn from 2014 to 2017, differentials seemed to work in the producer's favor. In fact, in 2017, western Canadian heavy oil averaged $12/bbl beneath WTI—a stronger level than what would otherwise be expected.[4] However, in 2018, western Canadian supply began exceeding available pipeline capacity, forcing some producers to seek alternative means to market, most notably crude-by-rail. Canadian oil exports by rail more than doubled over 2018, from 144,000 b/d in January to 354,000 b/d in December.[5] Despite this rapid expansion, movements still lagged demand. Some producers faced the prospect of not being able to move their product to market and were forced to discount their barrels by increasingly larger amounts, which led to a widening of the differential. In 2018, the western Canadian heavy oil differential, as tracked by WCS, averaged $27/bbl below WTI—more than double that in 2017. Moreover, over the course of the year, the differential ranged wildly from $11/bbl to more than $50/bbl beneath WTI—the worst level in recorded history.

The impact of the volatility in the western Canadian differentials transferred to the price of oil in western Canada—above and beyond global price volatility. At its worst, the price of western Canadian heavy oil reached lows of $14/bbl around mid-November. This result was lower than that in early 2016 during the nadir of the global oil price collapse.

Because differentials impact the price of oil received by producers in western Canada, they have a direct and pronounced impact on oil sands economics. Generally, the wider the differential, the lower the price of oil in western Canada relative to global benchmarks and thus the higher the break-even price will be required to offset the differential. When differentials were at their narrowest in 2018—about $11/bbl beneath WTI—we estimate that a new greenfield SAGD project would require a WTI price in the low $40s/bbl (and expansion of an existing facility being even lower) to break even. At the worst or widest differential in 2018, the differential exceeded $50/bbl. If sustained, the implied breakeven would have ballooned to nearly $100/bbl. For unintegrated mines, the breakeven ranged from $60/bbl to $120/bbl, WTI.

The extreme price volatility in late 2018 resulted in the Government of Alberta intervening in the market to reduce the extraordinary price differentials by mandating a cap on oil production in 2019. This action, coupled with a tightening of available heavy oil globally, principally from further deterioration of Venezuelan production, has contributed to narrower than historical light-heavy spreads and thus attractiveness of oil sands project economics. Over the first quarter of 2019, the differentials averaged about $12/bbl between WCS and WTI. However, it is expected that as Alberta eases production limits, known as curtailment, over 2019, the differentials should increase to reflect the higher cost of crude-by-rail. The decision by the government may have bought the industry time to bring in additional rail capacity to prevent a recurrence of the extreme volatility seen in 2018. However, the uncertainty of unresolved pipeline issues and potential for price volatility is contributing to price insecurity in western Canada in the immediate term.

## An uncertain investment climate

Investments in the Canadian oil sands are generally based on the long-term potential returns that accrue from projects that can produce oil for multiple decades—a time horizon that is unique in the world of oil production. However, investments in the Canadian oil sands are not immune to investor confidence, which tends to take a much shorter view.

Ongoing campaigns against the expansion of the Canadian oil sands have contributed to multiple delays in the timing of new pipeline takeaway capacity, which ultimately contributed to the extreme price volatility of 2018.

4. For more information on why this premium occurred, see the IHS Markit Strategic Report *Looking north: A US perspective on Canadian heavy oil*.

5. Source: National Energy Board, "Canadian Crude Oil Exports by Rail – Monthly Data," https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/cndncrdlxprtsrl-eng.html, accessed 24 February 2019.

Investors are now questioning Canada's ability to complete the necessary pipeline infrastructure projects and thus the potential value of western Canadian crude.

Out of a fleet of five originally proposed pipeline projects, three remain in the race (see Table 1), with the average length of time in review now exceeding three-quarters of a decade. The Line 3 Replacement project is currently the most advanced and could be online in the second half of 2020. This project is followed by the Keystone XL and Trans Mountain pipeline projects, which could stream in late 2021 and 2022, respectively—although Keystone XL is increasingly looking like it may not be online until 2022 as well. IHS Markit estimates that Line 3 will be insufficient on its own to absorb the existing production potential in western Canada and that additional capacity is required. In the interim, IHS Markit believes crude-by-rail will be a critical component of the western Canadian transportation mix, with a structural element remaining in place over the long term.

Historically, industry hesitated in investing in additional rail capacity based on the anticipated timing of future pipelines that in the end have continued to be delayed. In the end, however, supply ended up overtaking available takeaway capacity in 2018. This result encouraged a more rapid expansion of crude-by-rail. It is hoped that the Alberta government's action to curtail production will provide time for additional capacity—both pipe and rail—to be brought online to prevent a future shortfall in takeaway capacity.

## A more modest oil sands growth scenario emerging

Despite remarkable cost reductions outlined in this report, the western Canadian oil market continues to move through a period of price uncertainty. This period of uncertainty was first brought on by the shift to lower global oil prices that began in 2014 but is now largely dominated by regional price disparities stemming from significant delays to the timing of advancing pipeline projects. To add complexity, there are yet more challenges on the horizon for the industry, including the pending international low-sulfur marine fuel specification coming into force in 2020, which could once again weaken heavy crude prices relative to light crudes.[6] These challenges—particularly around the value of western Canadian heavy oil—are expected to continue to contribute to hesitation over future large-scale investment decisions in the Canadian oil sands until some of the uncertainty can be resolved.

Looking out over a longer horizon, IHS Markit believes growth will continue in the Canadian oil sands—albeit at a much slower pace. During 2009–18, oil sands grew at an annual average rate of approximately 160,000 b/d. Over the coming decade (and a bit), from 2018 to 2030, IHS Markit expects oil sands additions to average

Table 1

**Major long-distance Canadian crude oil export pipeline projects**

| Destination | Pipeline project (proponent) | Route | Incremental capacity (b/d) | Review initiated | Status |
|---|---|---|---|---|---|
| US markets | Line-3 Replacement (Enbridge) | Edmonton, Alberta, to Superior, Wisconsin | About 380,000 | 2012 | Permitting |
| | Keystone XL (TransCanada) | Hardisty, Alberta, to US Gulf Coast region | 830,000 | 2008 | In review |
| Eastern Canada and East Coast offshore | Energy East (TransCanada) | Hardisty, Alberta, to tidewater in Saint John, New Brunswick | 1.1 million | 2014 | Canceled |
| West Coast offshore | Northern Gateway (Enbridge) | Bruderheim, Alberta, to Kitimat, British Columbia | 525,000 | 2010 | Denied |
| | Trans Mountain Expansion (Government of Canada) | Edmonton, Alberta, to tidewater in Burnaby, British Columbia | 590,000 | 2013 | In review |

Source: Various sources, IHS Markit



6. For more information on the low-sulfur marine fuel specification, see https://ihsmarkit.com/research-analysis/navigating-choppy-waters-initial-findings.html and https://ihsmarkit.com/Info/0818/navigating-choppy-waters.html.

beneath 100,000 b/d per year. Although more modest than the past decade, the anticipated growth should still be sufficient to allow oil sands production to top 4 MMb/d by 2030—1 MMb/d more than in 2018. This level of growth may seem significant, but a lot of supply can come simply through optimization and ramp-up of existing or recently completed facilities. In fact, nearly one-third of growth in the IHS Markit outlook to 2030 comes from ramp up, optimization, and then sustaining of existing facilities. Key to the scale of future growth will be the ability of government and industry to restore confidence that Canadian crude oil will get to market by pipe or rail.

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# Looking south

A Canadian perspective on the US Gulf Coast heavy oil market

3 April 2018

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Canadian Oil Sands Dialogue | **Strategic Report**

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# Looking south

## A Canadian perspective on the US Gulf Coast heavy oil market

### About this report

**Purpose.** Since 2009, IHS Markit has made research public on issues surrounding the development of the Canadian oil sands. More heavy, sour crude oil (heavy oil) from the oil sands is expected to supply the United States and specifically the US Gulf Coast (USGC) region. The USGC is home to the largest concentration of complex heavy crude oil refineries in the world—an ideal match for growing Canadian heavy supply from the oil sands. This is the first of two reports that will explore the long-term relationship potential between USGC heavy oil refiners and upstream oil sands heavy oil suppliers.

**Context.** This report is part of a series of reports from the IHS Markit Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. This report is part one of two reports exploring the long-term relationship between Canadian heavy oil production and US heavy, sour demand.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

**Structure.** This report has five sections.

- Introduction
- The rise of Canadian heavy oil
- The US Midwest: The largest market for Canadian oil
- The USGC: The world's largest heavy oil market
- Importance of a Canadian offshore hedge

# Looking south

## A Canadian perspective on the US Gulf Coast heavy oil market

### Key implications

Canada is the world's largest producer of heavy, sour crude oil (heavy oil) and the United States is the world's largest consumer. With demand satisfied in the US Midwest, increasing volumes of Canadian heavy oil have begun to reach the US Gulf Coast (USGC)—which accounts for half of all US heavy oil demand. Heavy oil supply from Canada competes with production from Mexico and Venezuela, and the USGC market is not limitless. This report explores the relationship potential between USGC refiners and Canada's oil sands.

- **The United States and, in turn, the USGC is the world's largest consuming market for heavy oil.** Heavy oil processing capacity allows refiners to optimize operations over a greater range of crudes, which include lower-cost heavy crude oil. In 2017, the US market consumed more than 5 MMb/d of heavy oil, with nearly 3 MMb/d in the USGC region alone. More than 90% of this demand was met by imports.
- **Canadian supply has begun to reach the USGC at a timely moment when supply from key competitors, such as Mexico and Venezuela, is waning.** Declining availability from traditional sources of heavy oil imports has provided opportunities for Canadian crude oil of similar quality. Conversely, USGC refiners have benefited from greater access to growing Canadian supply.
- **Canadian heavy oil is a good substitute for Latin American heavy oil, but the two are not identical.** Subtle differences, such as a higher proportion of lighter ends in diluted bitumen (the dominant source of Canadian heavy oil growth) compared with Mexican Mayan crude, can present a challenge for some refiners looking to run greater levels of Canadian crude. Overcoming these differences is not insurmountable but may require greater incentives for refiners.
- **From the Canadian perspective, there are risks to overreliance on the US market.** US supply and demand fundamentals exert much influence on the value of Canadian crude oil. Should the USGC heavy oil market become more competitive in the future, Canadian heavy oil may have to compete more aggressively on price.

—3 April 2018

# Looking south

## A Canadian perspective on the US Gulf Coast heavy oil market

**Kevin Birn,** Vice President

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## Introduction

Since 2000, Canadian crude oil production has grown more than 2 MMb/d—the third-fastest pace in the world behind Russia and the United States—faster than Saudi Arabia, Iran, and Iraq. In 2017, Canada was the fifth-largest producer of crude oil globally and the single-largest source of crude oil imports to the United States. In 2017, the United States imported more than 3.4 MMb/d from Canada—more than all of OPEC combined.[2]

Canada's growth has been propelled by investment in the oil sands, and heavy, sour crude oil (heavy oil) has dominated Canadian supply output. In 2017, Canada produced more than 4.1 MMb/d, about half of which was heavy oil.[3]

Oil sands production growth is on course to decelerate, but significant gains are still anticipated. By 2025, oil sands supply may be almost 1.4 MMb/d greater than in 2017—reaching 4.5 MMb/d—with more than 90% of the growth in supply being heavy oil.

The dominance of heavy oil growth has allowed Canadian crude oil exports to complement US light, tight oil growth. Tight oil supply primarily meets the needs of less complex light, sweet crude oil refineries (displacing offshore imports of light, sweet crude). Heavy oil supply from Canada meets the needs of more complex heavy crude oil refineries. Access to growing US and Canadian crude oil—light and heavy—has, in turn, made North America more energy self-sufficient, shoring up domestic refining runs and increasing continental energy security.

The single-largest market for Canadian crude oil exports has been the US Midwest. In 2017, IHS Markit estimates the US Midwest consumed nearly half of all Canadian crude oil exports. Conversely, over two-fifths of the crude oil processed in the US Midwest came from Canada, three-quarters of which was heavy oil. However, the US Midwest may be nearing its limit to consume increasing volumes of Canadian supply. More Canadian crude oil is now flowing to the US Gulf Coast (USGC) region. The USGC is home to the world's largest concentration of heavy oil refineries—an ideal match for growing Canadian output. However, Canada's expanding reliance on the US market brings challenges and risks. This report will explore the potential for further Canadian and US oil market integration.

Throughout this report, some common terms are used to describe the oil sands, refining, and crude oil quality. These are discussed in the boxes "Canadian oil sands primer" and "Heavy oil 101."

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1. Special thank you to Steve Fekete, Managing Director at IHS Markit.

2. This estimate is based on the first 10 months of 2017 as derived from the US Energy Information Administration's (EIA) "US Imports by Country of Origin," 31 January 2018, retrieved 16 February 2018.

3. It is important to note that supply exceeds production in Canada, because oil sands producers that choose to market heavy crude oil must dilute bitumen with lighter hydrocarbons. Often, condensate or pentane plus hydrocarbons are imported from the United States and elsewhere to meet demand. On a supply basis, Canada marketed more than 4.3 MMb/d in 2017. Because of this blending, about two-thirds of supply is heavy oil. Although oil sands are the single-largest source of Canadian heavy oil, they are not the only Canadian source.

## Canadian oil sands primer

The immensity of the oil sands is their signature feature. Current estimates place the amount of crude oil that can be economically recovered from the Canadian oil sands at 166 billion bbl, 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, sour crude oil with high viscosity. Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with light oil or converted into a synthetic light crude oil. Different grades of crude oil are produced from bitumen.

**Bitumen blends.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. The blend density is between 923 kg and 940 kg per cubic meter (20–22° API gravity), making it comparable to other heavy crudes, such as Mexican Maya. The most common bitumen blend is diluted bitumen (dilbit)—typically about 70% bitumen and 30% lighter hydrocarbons. We expect the vast majority of oil sands supply growth in the future to be bitumen blends, specifically dilbit.

**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.

## Heavy oil 101

Crude oil is not homogeneous. It can vary depending on density (light or heavy) and quality (the presence of impurities such as sulfur, giving rise to terms like sweet or sour). Density is by far the most common metric of quality, which is measured according to API gravity. Light crude oil generally has an API gravity of 32° or higher. Heavy crude oil has an API gravity below 24° (with the API gravity for extra-heavy crude oil below 10°). Medium crudes have an API gravity between light and heavy crudes. The sulfur content for sweet crude oil is less than 1wt%, with levels for sour crude oil exceeding this amount.

Differences in density result from the composition of hydrocarbons found in a given crude oil. Different hydrocarbon molecules have different properties. Generally, the longer or more complex the hydrocarbon, the "heavier" the molecule and the higher its boiling point. The greater the share of these molecules in a given crude oil, the heavier the oil is, and more energy is required to convert the oil into higher-value refined products, such as gasoline.

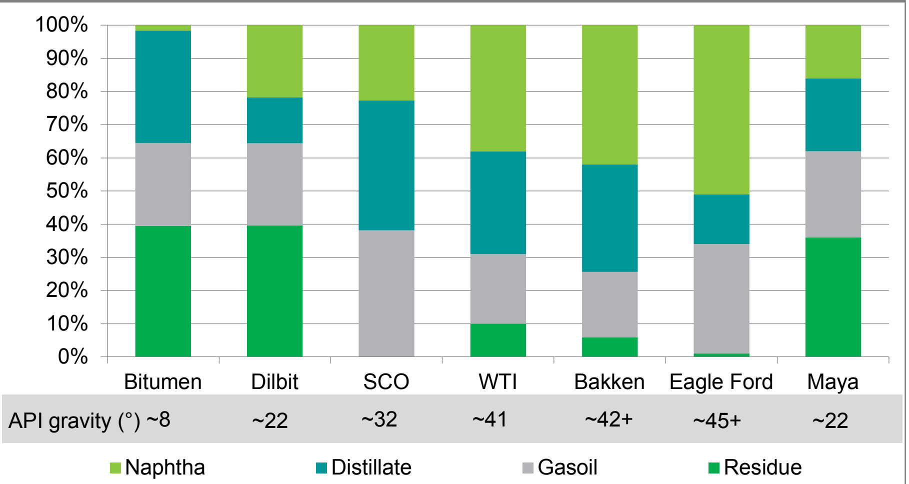
Different crude oils will vary in their ability to be converted into different refined products. Within any given barrel of oil, there are various fractions, or groupings, of hydrocarbons that distill or boil at distinct temperature ranges. Naphtha is the lightest fraction and boils at a lower temperature. Gasoline is generally derived from naphtha. Kerosene (jet fuel) and diesel are found in the distillate range, boiling at higher temperatures between 180°C and 350°C. Vacuum gasoil and residue are viscous materials that boil between 350°C and 550°C, respectively. These fractions require additional processing (via catalytic or thermal processes) to be converted into lighter fractions of distillate and naphtha, which can then be converted into higher-value products. Less complex refineries (facilities that lack additional heavy crude oil processing technology) will not be able to process these heavier fractions into lighter products. As a result, they will pay a premium for lighter crude oil. By contrast, more complex refineries—facilities that have invested in specialized units capable of converting heavy fractions to light products—will seek out crude oil with larger fractions of heavy molecules. Because of the complexity and cost required to process heavier crude oils, they typically are cheaper than lighter crude oil.

## The rise of Canadian heavy oil

Bitumen found in the oil sands is an extra-heavy, sour crude oil and features a large fraction of residue (nearly half) (see Figure 1). To convert a barrel of oil from the oil sands (the residue specifically) into a refined product, such as gasoline or diesel, refiners need to have made large capital investments in specialized heavy crude oil processing units. If refiners have not made these investments, they will be unable to convert many of these heavier molecules into higher-value refined products and will have to sell lower-value intermediate products to facilities with the ability to handle them.

Figure 1

**Assay of key crude oils**




Note: Crude assays will vary. Values are approximations and will vary by cut point and reservoir quality, which does vary across a play and over time. Estimate assembled from various sources and adjusted based on feedback.
Source: Derived and adapted from IHS Markit, US EIA, CrudeMonitor.ca © 2018 IHS Markit

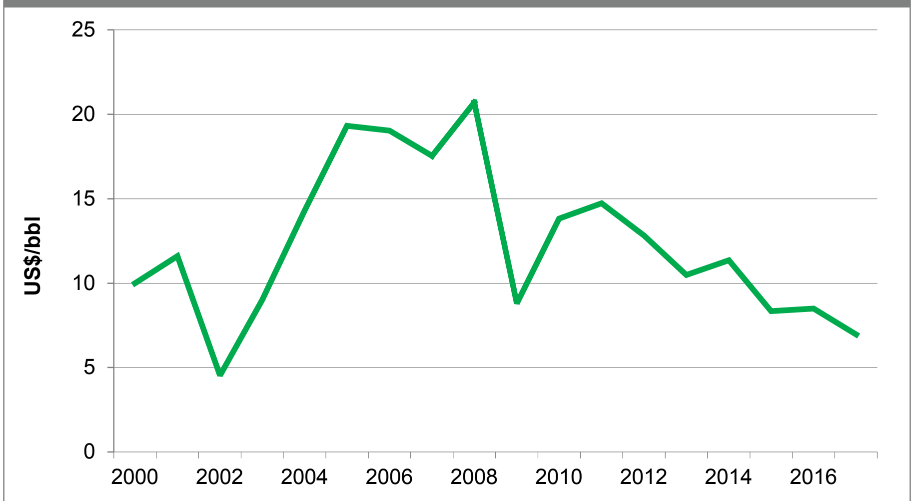
Over time, refiners tailor their operations toward available crude oil as historical sources decline and new sources arise. However, the decision to invest in heavy oil processing capacity is significant. Heavy processing units, such as a delayed coker (vessels capable of reaching the temperature and pressure required to convert residue into lighter fractions), typically cost well over US$1 billion.[4] Refiners will weigh this cost against the estimated savings from being able to process lower-value heavy crude oil over continuing to purchase and run higher-priced lighter crude oils. The price differential between light crude oil and heavy crude oil is known as the light-heavy differential.

The difference in price between light and heavy crude oil is set by the relative demand for these two general categories of crude oil. This is influenced by the demand for light and heavy refined products as well as the availability of heavy conversion capacity.

Preceding the US tight oil boom, the availability of heavy oil was on the rise while light, sweet crude oil was in decline. This contributed to a wider price difference between light and heavy crude oil, which supported investments in more complex refining capacity (see Figure 2). This occurred first in the USGC, through a number

Figure 2

**Global light-heavy crude oil price differential (2000–17)**




Note: Based on difference between Louisiana Light Sweet and Maya FOB Mexico.
Source: Argus Media, IHS Markit © 2018 IHS Markit

4. Delayed cokers use high temperature and residence to crack the complex molecules found in residue into lighter fractions, which can then be converted into higher-value refined products.

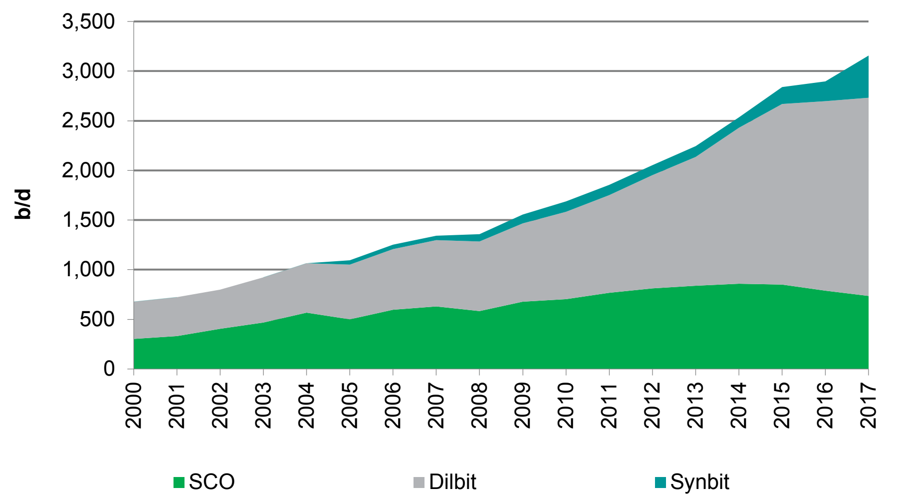
of JVs and crude oil supply arrangements, to meet growing supply from Latin America, then later in the US Midwest to take advantage of growing volumes of heavy oil from Canada.

Investments were also made in the oil sands for economic and technical reasons to convert the large fraction of residue in bitumen into lighter fractions. This was called upgrading. The resulting ("bottomless") SCO product could then be marketed to refiners that lacked heavy oil processing capacity.[5] However, over time, new forms of extraction, which often lacked the scale of mining operations, and the appreciation of the cost to construct upgraders reduced interest in upgrading (but has not eliminated it).[6]

Heavy oil growth, particularly bitumen blends and specifically dilbit, has outpaced SCO supply growth in the Canadian oil sands (see Figure 3). In 2012, bitumen blends overtook SCO as the dominant source of oil sands supply. This trend was helped along by the renaissance of US tight oil production, which provided an ample supply of light, sweet crude oil. This has diminished the price difference between light and heavy crude oil and, in turn, the economic incentive to further expand bitumen upgrading in Canada.

Figure 3

Canadian oil sands supply by major marketed product




Note: Synbit is a roughly 50/50 blend between SCO and bitumen.
Source: IHS Markit

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## The US Midwest: The largest market for Canadian oil

Crude oil production in western Canada has long surpassed regional demand, and increasing volumes have found a home in the United States. In 2017, Canada produced 4.1 MMb/d in total, and the oil sands accounted for about 2.6 MMb/d. On a supply basis, which accounts for Canadian imports of condensate (from the United States and offshore) used to create dilbit, Canada exceeded 4.3 MMb/d in 2017, with oil sands topping 3.1 MMb/d.

The single-largest market for Canadian oil of all grades (light to heavy) continues to be the US Midwest. However, volumes are increasing in the USGC region, which is home to the world's largest concentration of heavy, sour complex refining capacity. These two markets—key for current and future Canadian heavy crude oil supply—account for nearly three-quarters of total US crude oil refinery demand, processing over 12 MMb/d in 2017, one-third of which, or over 4 MMb/d, was heavy oil.

The rise of Canadian imports, until recently, had been supported by the historical decline in US supply. From the mid-1970s until the dawn of the tight oil revolution, the availability of domestic crude oil for refiners steadily fell. US Midwest refineries historically processed US domestic crude oils and foreign imports delivered inland via pipeline from ports in the USGC. Refiners in the US Midwest invested in expanding heavy crude oil processing capacity to access growing volumes from Canada. Over the past decade (2008–17), heavy crude

5. SCO may be referred to as bottomless because nearly all the residue has been converted to lighter fractions (see Figure 1).

6. Steam-assisted gravity drainage technology played a major role in enabling production of a marketable heavy crude oil, which was not possible for mined bitumen using naphthenic froth separate processes. More recently, advances in paraffinic froth treatment have allowed the development of mines without upgraders. For more information, see the IHS Markit Strategic Report *A New Look: Extracting economic value from the Canadian oil sands*.

oil processing increased by about 500,000 MMb/d. Over the same period, a combination of growing US domestic tight oil and Canadian supply collapsed offshore imports into the US Midwest by 400,000 b/d, to near negligible levels today. Nearly every barrel imported into the US Midwest today comes from Canada. In 2017, the region consumed 3.6 MMb/d—with 90% split almost equally between Canadian and domestic supply—and more than one-third was heavy oil from Canada.[7]

With supply overtaking US Midwest demand, increasing volumes of heavy oil from Canada must find a new home: the most logistically approximate and technically suited is the USGC.

## The USGC: The world's largest heavy crude oil market

The USGC region is one of the largest refining centers in the world and home to the world's largest concentration of heavy oil processing capacity. In 2017, the region processed nearly 8.7 MMb/d of crude oil, of which 2.8 MMb/d was heavy oil. Although the USGC has the potential to become the largest market for Canadian crude oil exports, it is not limitless, and there are challenges that may come at a cost for Canadian producers.

### Light, tight oil to limit demand growth for heavy, sour crude

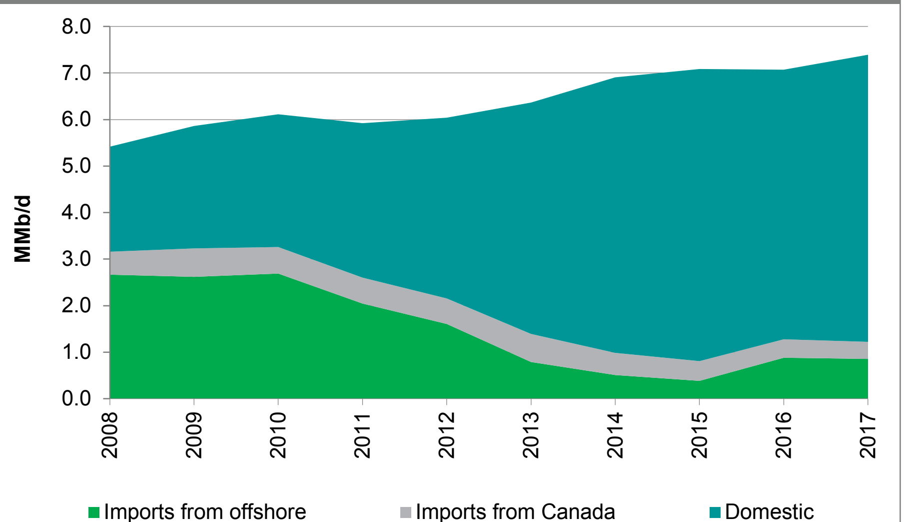
Over a very short period—since the start of the decade—the US oil market has changed remarkably. The revolution in tight oil has ushered in an era of abundant domestic supplies of light, sweet crude oil. Meanwhile, the output of traditional sources of heavy crude oil imports to the United States—namely Venezuela and Mexico—has fallen. Lower prices accelerated the decline of Mexican Mayan heavy oil and exacerbated the economic and political crisis in Venezuela, which, in turn, has contributed to greater production losses. These factors have contributed to a reduction in the light-heavy crude oil differential globally, reducing the economic incentive to invest further in expanding downstream heavy oil processing capacity (as well as reducing the incentive to upgrade in Canada).

IHS Markit expects that growing supplies of light, tight oil in the United States will encourage refiners to invest in consuming more of it. Indeed, over the past decade (2008–17), total runs of light, sweet crude increased 1.1 MMb/d, while US domestic supply growth displaced 1.8 MMb/d of offshore imports of similar quality (see Figure 4).

Yet, although investments to increase heavy oil processing capacity may have diminished with the rise of light, tight oil, existing heavy processing capacity is not expected to be idled.[8] Heavy crude oil processing capacity, such as cokers, represents a significant

Figure 4

US consumption (refinery runs) of light, sweet crude oil by region




Source: IHS Markit © 2018 IHS Markit

7. The US Midwest imports a range of crude oils from Canada, from light to heavy, but heavy oil is—by far—the largest share.

8. Investments are expected to expand the "top end," such as naphtha handling, which is found at greater quantities in tight oil and even oil sands dilbit than historical supply in the region.

investment and once installed allows refiners to process lower-value, and thus lower-cost, feedstock. Once this capacity is operational, refiners will not want to idle it.

Indeed, from 2008 to 2017, USGC heavy oil consumption increased by more than 750,000 b/d, while equivalent offshore imports declined 160,000 b/d. Although the availability of traditional imports from key Latin American suppliers has been declining, increased availability and access to Canadian heavy crude oil has thus far been able to more than offset these declines, resulting in greater refinery runs.

## Canadian heavy crude oil will have to compete

Despite logistical challenges facing Canadian supply, it has begun to reach the USGC at a time when supply from key competitors is waning.[9] Over the past five years, production from key sources of historical heavy oil imports, such as Mexico and Venezuela, has declined by nearly 1 MMb/d. This has helped to make growing Canadian heavy oil supply an attractive substitute.

Although Canadian imports are of similar quality as Latin American crudes, they are not identical. Compared with Mexican Mayan, oil sands dilbit (from the Athabasca region specifically)—the dominant source of Canadian heavy, sour supply growth—has similar fractions of vacuum gasoil and residue but larger fractions of naphtha and less distillate (see Figure 1). Given the relatively larger fractions of heavy and light, the distillation of dilbit is referred to as “dumbbell” given the nonhomogeneous boiling curve of the crude. Refiners can manage some differences between crudes by blending various crude oils as well as making minor modifications to existing processing units. However, all things being equal, there is a point when more extensive modifications will be required to better tailor facilities toward dilbit. Should dilbit exports continue to dominate, loosely speaking, volumes under 1.2 MMb/d should be readily accommodated with minor modifications (based on available residue processing capacity and corresponding light ends handling capacity at these refineries). However, as volumes exceed this level, more extensive modifications may be required.[10]

As volumes build, USGC refiners may require greater incentives to process increasing quantities of Canadian heavy crude oil over entrenched offshore competition. This then comes down to the availability of traditional competitive sources of supply and the price. Should Latin American heavy oil supply continue to decline, this would push refiners to more aggressively seek out alternative sources of heavy oil supply—to Canada’s benefit. However, should Latin American supply prove more resilient, Canadian crude oil may have to compete for space sooner. For crude oil, competition is about price; and in the absence of an alternative outlet market, this implies that Canadian crude oil would have to discount or price under crude oil of comparable quality to encourage refiners to make the necessary modifications.

The degree of the discount may be within a few dollars, but it could translate to a reduction in the economic value to Canada. Moreover, with millions of barrels per day of exports, the discount would add up. The theoretical price floor is set by the cost to move Canadian crude oil farther afield to more distant markets, including refiners not currently connected by pipelines to the Houston refinery complex.[11]

9. See the IHS Markit Strategic Report *Pipelines, Prices, and Promises—The story of western Canadian market access*.

10. To be certain, any estimate of crude quality fit is an approximation. There is variability in bitumen and therefore dilbit quality across the oil sands (as with any crude-producing region), which will influence the potential modifications that may be required as greater volumes reach the USGC. For example, dilbit from the Cold Lake region is a closer match to Mexican Maya than Athabasca dilbit. The estimate presented in this report is based on Athabasca dilbit because the majority of growth is expected to come from Athabasca in the IHS Markit outlook. In addition, creation or marking of alternative blends that use less natural gas condensate (the principal contributor to the large naphtha share in dilbit) or refiners rejecting naphtha could also affect refiners’ abilities to process greater volumes of heavy oil from Canada. All of these factors—bitumen quality, naphtha rejection, and creation of alternative blends—will influence the volume and type of modifications that may be required to substitute greater volumes of Canadian heavy oil for traditional offshore sources of heavy oil.

11. Planned infrastructure to deliver Canadian heavy oil into the USGC would provide access from Houston/Port Arthur to New Orleans. Although this provides access for the majority of the heavy oil capacity in the region, operations farther afield, such as in Mississippi, exist.

## Importance of a Canadian offshore hedge

The United States, particularly the US Midwest and now the USGC, is expected to remain the most significant crude oil export market for Canada. With traditional sources of offshore heavy oil supply in decline, Canadian supply has become an attractive substitute. All indications are that heavy crude oil trade will grow between Canada and the United States—an effective match to the benefit of both parties. IHS Markit estimates that current runs of Canadian crude in the USGC are already in excess of 800,000 b/d—far greater than headline EIA import data would indicate due to commingling, storage, and internal transfers within the United States.[12] By 2020, IHS Markit estimates that with increased rail movements, runs of Canadian heavy could top 1.2 MMb/d—a full one-third of the region's heavy oil market.

Although the United States provides security of demand for Canada, there are risks to Canada from overreliance. The IHS Markit forecast assumes the completion of all three remaining major long-distance export pipelines: Enbridge Mainline expansion (Line 3 Replacement Project, specifically), TransCanada Keystone XL, and Kinder Morgan Trans Mountain Expansion Project.[13] The first two pipelines would permit increased flows of western Canadian crude oil to the USGC; the Trans Mountain pipeline would deliver Canadian crude oil offshore via a port on Canada's west coast. If the Trans Mountain pipeline continues to meet delays, or Canadian or competitive heavy oil supply is more prolific than anticipated, Canada may have to compete more aggressively for market share in the United States. In this instance, Canadian crude oil may have to discount to incentivize refiners to make even greater modifications to better tailor their facilities to Canadian heavy oil supply and/or displace greater quantities of offshore imports.

Alternative diversification strategies can help mitigate some of these risks. These could involve customizing oil sands blends or developing upstream partial processing technologies that would result in the marketing of a greater range of crude oil qualities. This would allow oil sands to meet the needs of more US refiners, expanding market share and integration with the US market. Yet, given the scale of Canadian heavy oil supply today and anticipated growth, these solutions would not remove the risk and would still take considerable investment and time. For Canada—the fifth-largest oil producer in the world—its almost singular reliance on one market is unique in the world, and there are associated risks.

12. EIA tracks overland crude oil imports when they "break bulk," which means when the crude oil is unloaded or leaves the pipeline. IHS Markit believes that Canadian heavy oil imports may be "stopping off" at Cushing, which would result in a reported delivery into PADD 2 as opposed to PADD 3.

13. See the IHS Markit Strategic Report *Pipelines, Prices, and Promises—The story of western Canadian market access*.

## IHS Markit team[14]

**Kevin Birn,** Vice President, IHS Markit, is part of the IHS Markit North American Crude Oil Markets team, leads the IHS Markit Oil Sands Dialogue. Mr. Birn is responsible for a team of oil market analysts focused on western Canada. Mr. Birn has authored more than 40 reports associated with the development of the Canadian oil sands. His expertise includes Canadian oil sands development, oil sands cost and competitiveness, crude oil markets, crude oil transportation logistics, greenhouse gas intensity of crude oil, and Canadian energy and climate policy. Mr. Birn has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US secretary of energy. Prior to joining IHS Markit, Mr. Birn was a senior economist with the Government of Canada and a partner in a software firm. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta. He is based in Calgary.

**Vijay Muralidharan,** Director, IHS Markit, is part of the IHS Markit North American Crude Oil Markets team and is an integral part of the IHS Markit Oil Sands Dialogue. In addition, he supports the oil market analysis team with a focus on western Canada. Mr. Muralidharan has more than 12 years of experience in upstream, midstream, and downstream global oil and gas economic evaluation. His expertise includes crude oil market analysis, macroeconomics, risk analysis, oil asset evaluation, technology, crude oil logistics, and Canadian energy and climate policy. Prior to joining IHS Markit, Mr. Muralidharan held posts at ConocoPhillips, Statoil, EY, and Bank of Canada. As a senior economist in Norway with Statoil, he oversaw the global macroeconomic forecast, where he provided assistance to the global energy market group. He has authored many reports, both in the public and private sector, and won the John Vanderkamp Prize for best public policy paper in 2006. Mr. Muralidharan holds an undergraduate degree and a graduate degree from the University of Alberta. He is based in Calgary.

**Patrick Smith,** Research Analyst, IHS Markit, is part of the North American Crude Oil Markets team. His responsibilities include the delivery of market research concerning supply and demand analysis, price forecasting, transportation, and overall policy and geopolitical issues that influence oil markets. Prior to joining IHS Markit, Mr. Smith was an energy market analyst at Cenovus Energy in its Market Fundamentals and Hedging department. Mr. Smith holds a BComm from Dalhousie University.

14. Special thank you to Steve Fekete, Managing Director at IHS Markit.

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# The greenhouse gas intensity of oil sands production

Appendix A: Data tables/results

September 2018

# The greenhouse gas intensity of oil sands production

## Appendix A: Data tables/results

Table A-1

### Oil sands GHG emission intensity summary results: History and outlook to 2030

| | | Historical | | | | | | | | | | Forecast | | | | | | | | | | | | | | % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Upper-bound case (more conservative)** | **Units** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **% change, 2008/09–17** | **change, 2017–30** |
| CSS* | $kgCO_2e$/bbl of dilbit | N/A | 96 | 77 | 69 | 68 | 71 | 73 | 76 | 89 | 90 | | | | | | | | | | | | | | -7% | |
| SAGD | $kgCO_2e$/bbl of dilbit | N/A | 66 | 63 | 64 | 65 | 65 | 62 | 62 | 64 | 63 | 62 | 62 | 63 | 62 | 61 | 60 | 58 | 57 | 56 | 54 | 53 | 53 | 52 | -4% | -17% |
| **In situ average** | **$kgCO_2e$/bbl of dilbit** | **N/A** | **80** | **69** | **66** | **66** | **67** | **65** | **66** | **68** | **68** | **66** | **65** | **66** | **65** | **64** | **63** | **62** | **60** | **60** | **58** | **57** | **56** | **55** | **-16%** | **-18%** |
| Mined SCO | $kgCO_2e$/bbl of SCO | 112 | 115 | 108 | 104 | 110 | 105 | 105 | 97 | 92 | 91 | 88 | 91 | 90 | 90 | 88 | 88 | 88 | 87 | 87 | 87 | 86 | 86 | 86 | -18% | -6% |
| Mined dilbit (PFT) | $kgCO_2e$/bbl of dilbit | - | - | - | - | - | 98 | 57 | 48 | 47 | 46 | 45 | 41 | 41 | 41 | 41 | 41 | 40 | 40 | 40 | 40 | 39 | 39 | 39 | | -15% |
| **Mining average** | **$kgCO_2e$/bbl of product** | **112** | **115** | **108** | **104** | **110** | **105** | **101** | **89** | **83** | **83** | **75** | **75** | **74** | **74** | **73** | **73** | **73** | **72** | **72** | **72** | **71** | **71** | **71** | **-28%** | **-15%** |
| **Average (of shown)**** | **$kgCO_2e$/bbl of product** | **N/A** | **100** | **90** | **85** | **87** | **84** | **80** | **76** | **74** | **74** | **70** | **69** | **69** | **69** | **68** | **67** | **66** | **65** | **64** | **63** | **62** | **61** | **60** | **-27%** | **-18%** |
| | Share of supply | - | 84% | 86% | 86% | 85% | 85% | 86% | 88% | 90% | 92% | 93% | 93% | 93% | 93% | 93% | 94% | 94% | 94% | 94% | 94% | 94% | 94% | 94% | | |
| **Industry average***** | **$kgCO_2e$/bbl of product** | **N/A** | **89** | **84** | **79** | **81** | **79** | **76** | **73** | **70** | **70** | **67** | **67** | **67** | **67** | **66** | **65** | **64** | **63** | **62** | **61** | **60** | **60** | **59** | **-21%** | **-16%** |
| | Share of supply | - | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | | |
| **Lower-bound case (more aggressive)** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| CSS* | $kgCO_2e$/bbl of dilbit | N/A | 96 | 77 | 69 | 68 | 71 | 73 | 76 | 89 | 90 | | | | | | | | | | | | | | -7% | |
| SAGD | $kgCO_2e$/bbl of dilbit | N/A | 66 | 63 | 64 | 65 | 65 | 62 | 62 | 64 | 63 | 62 | 61 | 62 | 60 | 59 | 58 | 56 | 54 | 53 | 50 | 48 | 47 | 46 | -4% | -27% |
| **In situ average** | **$kgCO_2e$/bbl of dilbit** | **N/A** | **80** | **69** | **66** | **66** | **67** | **65** | **66** | **68** | **68** | **66** | **65** | **65** | **64** | **63** | **61** | **60** | **58** | **57** | **54** | **52** | **51** | **50** | **-16%** | **-26%** |
| Mined SCO | $kgCO_2e$/bbl of SCO | 112 | 115 | 108 | 104 | 110 | 105 | 105 | 97 | 92 | 91 | 88 | 90 | 90 | 89 | 87 | 87 | 87 | 86 | 83 | 83 | 82 | 82 | 82 | -18% | -10% |
| Mined dilbit (PFT) | $kgCO_2e$/bbl of dilbit | - | - | - | - | - | 98 | 57 | 48 | 47 | 46 | 45 | 41 | 41 | 40 | 40 | 40 | 39 | 39 | 38 | 38 | 35 | 35 | 34 | | -24% |
| **Mining average** | **$kgCO_2e$/bbl of product** | **112** | **115** | **108** | **104** | **110** | **105** | **101** | **89** | **83** | **83** | **75** | **74** | **74** | **74** | **72** | **72** | **71** | **71** | **69** | **68** | **67** | **67** | **67** | **-28%** | **-20%** |
| **Average (of shown)**** | **$kgCO_2e$/bbl of product** | **N/A** | **100** | **90** | **85** | **87** | **84** | **80** | **76** | **74** | **74** | **70** | **69** | **69** | **68** | **67** | **65** | **64** | **63** | **61** | **59** | **58** | **57** | **56** | **-27%** | **-25%** |
| | Share of supply | - | 84% | 86% | 86% | 85% | 85% | 86% | 88% | 90% | 82% | 84% | 84% | 85% | 85% | 85% | 86% | 86% | 86% | 87% | 87% | 87% | 87% | 88% | | |
| **Industry average (including primary and experimental)** | **$kgCO_2e$/bbl of product** | **N/A** | **89** | **84** | **79** | **81** | **79** | **76** | **73** | **70** | **70** | **67** | **67** | **67** | **66** | **64** | **63** | **62** | **61** | **60** | **58** | **56** | **55** | **54** | **-21%** | **-23%** |
| | Share of supply | 0% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | | |

Note: GHG = greenhouse gases; CSS = cyclic steam stimulation; SAGD = steam-assisted gravity drainage; SCO = synthetic crude oil; PFT = paraffinic froth treatment; $kgCO_2e$/bbl = kilograms of carbon dioxide equivalent per barrel; dilbit = diluted bitumen.

*No intensity improvements were modeled for CSS. For average in situ, CSS 2017 intensities were held constant but were allowed to fluctuate in accordance with the IHS Markit production outlook

**Includes CSS in outlook based on 2017 intensities but adjusting for production changes..

***Including primary and experimental.

Source: IHS Markit

Table A-2

## Upper-bound (more conservative) mined oil sands by process and component, 2008–30

| | | Historical | | | | | | | | | | Forecast | | | | | | | | | | | | | Percent | Percent |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Mined SCO** | **Units** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **change, 2008/09–17** | **change, 2017–30** |
| Natural gas | kgCO$_2$e/bbl of SCO | 41 | 41 | 38 | 35 | 45 | 38 | 40 | 38 | 38 | 38 | 38 | 39 | 38 | 38 | 46 | 45 | 45 | 45 | 45 | 45 | 44 | 44 | 44 | -7% | 14% |
| Produced gas | kgCO$_2$e/bbl of SCO | 29 | 32 | 31 | 31 | 25 | 34 | 33 | 27 | 24 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | -19% | 0% |
| Petroleum coke | kgCO$_2$e/bbl of SCO | 20 | 21 | 17 | 16 | 13 | 10 | 11 | 11 | 10 | 10 | 9 | 9 | 9 | 9 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | -53% | -50% |
| Mobile mine fleet | kgCO$_2$e/bbl of SCO | 9 | 9 | 10 | 9 | 9 | 9 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | -5% | -9% |
| Fugitives, venting, and flaring | kgCO$_2$e/bbl of SCO | 9 | 8 | 8 | 8 | 10 | 9 | 6 | 6 | 6 | 6 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | -37% | -5% |
| Carbon capture | kgCO$_2$e/bbl of SCO | - | - | - | - | - | - | - | -1 | -3 | -2 | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | | -4% |
| Electrical balance (import/export) | kgCO$_2$e/bbl of SCO | -4 | -3 | -2 | -1 | 0 | -1 | 0 | 1 | 1 | 1 | 0 | 1 | 1 | 2 | -5 | -5 | -5 | -5 | -5 | -5 | -5 | -5 | -5 | -129% | -518% |
| Upstream natural gas production | kgCO$_2$e/bbl of SCO | 7 | 6 | 6 | 6 | 7 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | -2% | 8% |
| Upstream diluent | kgCO$_2$e/bbl of SCO | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| **IHS Markit upstream GHG intensity** | **kgCO$_2$e/bbl of SCO** | **112** | **115** | **108** | **104** | **110** | **105** | **105** | **97** | **92** | **91** | **88** | **91** | **90** | **90** | **88** | **88** | **88** | **87** | **87** | **87** | **86** | **86** | **86** | **-18%** | **-6%** |
| **Mined dilbit (PFT)** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Natural gas | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 50 | 28 | 25 | 25 | 24 | 27 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 21 | 21 | 21 | 21 | 21 | | -13% |
| Produced gas | kgCO$_2$e/bbl of dilbit | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Petroleum coke | kgCO$_2$e/bbl of dilbit | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Mobile mine fleet | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 10 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | | -5% |
| Fugitives, venting, and flaring | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 8 | 3 | 1 | 1 | 1 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | 3% |
| Carbon capture | kgCO$_2$e/bbl of dilbit | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Electrical balance (import/export) | kgCO$_2$e/bbl of dilbit | 0 | 0 | 0 | 0 | 0 | 15 | 8 | 5 | 5 | 5 | -1 | 1 | 1 | 1 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | -73% |
| Upstream natural gas production | kgCO$_2$e/bbl of dilbit | 0 | 0 | 0 | 0 | 0 | 8 | 4 | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | | -13% |
| Upstream diluent | kgCO$_2$e/bbl of dilbit | 0 | 0 | 0 | 0 | 0 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | | 3% |
| **IHS Markit upstream GHG intensity** | **kgCO$_2$e/bbl of dilbit** | **0** | **0** | **0** | **0** | **0** | **98** | **57** | **48** | **47** | **46** | **45** | **41** | **41** | **41** | **41** | **41** | **40** | **40** | **40** | **40** | **39** | **39** | **39** | | **-15%** |
| **Mined average** | **Units** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Natural gas | kgCO$_2$e/bbl of dilbit | 41 | 41 | 38 | 35 | 45 | 39 | 39 | 36 | 36 | 36 | 35 | 33 | 33 | 33 | 38 | 38 | 38 | 37 | 37 | 37 | 37 | 37 | 36 | -13% | 2% |
| Produced gas | kgCO$_2$e/bbl of dilbit | 29 | 32 | 31 | 31 | 25 | 33 | 30 | 23 | 19 | 19 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | -34% | -17% |
| Petroleum coke | kgCO$_2$e/bbl of dilbit | 20 | 21 | 17 | 16 | 13 | 10 | 10 | 9 | 8 | 8 | 6 | 6 | 6 | 6 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | -62% | -58% |
| Mobile mine fleet | kgCO$_2$e/bbl of dilbit | 9 | 9 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 | 7 | 7 | -12% | -14% |
| Fugitives, venting, and flaring | kgCO$_2$e/bbl of dilbit | 9 | 8 | 8 | 8 | 10 | 8 | 6 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -46% | -17% |
| Carbon capture | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | - | - | -1 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | | -20% |
| Electrical balance (import/export) | kgCO$_2$e/bbl of product | -4 | -3 | -2 | -1 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 1 | 1 | 2 | -3 | -3 | -3 | -3 | -3 | -3 | -3 | -3 | -3 | -147% | -254% |
| Upstream natural gas production | kgCO$_2$e/bbl of product | 7 | 6 | 6 | 6 | 7 | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | -9% | -3% |
| Upstream diluent | kgCO$_2$e/bbl of product | - | - | - | - | - | 0 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | | 79% |
| **IHS Markit upstream GHG intensity** | **kgCO$_2$e/bbl of product** | **112** | **115** | **108** | **104** | **110** | **105** | **101** | **89** | **83** | **83** | **75** | **75** | **74** | **74** | **73** | **73** | **73** | **72** | **72** | **72** | **71** | **71** | **71** | **-26%** | **-15%** |

Source: IHS Markit



Table A-3

## Lower-bound (more aggressive) mined oil sands by process and component, 2008–30

| | | Historical | | | | | | | | | | Forecast | | | | | | | | | | | | | Percent | Percent |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Mined SCO** | **Units** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **change, 2008/09–17** | **change, 2017–30** |
| Natural gas | kgCO$_2$e/bbl of SCO | 41 | 41 | 38 | 35 | 45 | 38 | 40 | 38 | 38 | 38 | 38 | 38 | 38 | 38 | 45 | 46 | 45 | 47 | 44 | 44 | 44 | 44 | 43 | -7% | 13% |
| Produced gas | kgCO$_2$e/bbl of SCO | 29 | 32 | 31 | 31 | 25 | 34 | 33 | 27 | 24 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | -19% | 0% |
| Petroleum coke | kgCO$_2$e/bbl of SCO | 20 | 21 | 17 | 16 | 13 | 10 | 11 | 11 | 10 | 10 | 9 | 9 | 9 | 9 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | -53% | -50% |
| Mobile mine fleet | kgCO$_2$e/bbl of SCO | 9 | 9 | 10 | 9 | 9 | 9 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | -5% | -16% |
| Fugitives, venting, and flaring | kgCO$_2$e/bbl of SCO | 9 | 8 | 8 | 8 | 10 | 9 | 6 | 6 | 6 | 6 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | -37% | -5% |
| Carbon capture | kgCO$_2$e/bbl of SCO | - | - | - | - | - | - | - | -1 | -3 | -2 | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | | -4% |
| Electrical balance (import/export) | kgCO$_2$e/bbl of SCO | -4 | -3 | -2 | -1 | 0 | -1 | 0 | 1 | 1 | 1 | 0 | 1 | 1 | 2 | -5 | -5 | -5 | -7 | -7 | -7 | -7 | -7 | -7 | -129% | -756% |
| Upstream natural gas production | kgCO$_2$e/bbl of SCO | 7 | 6 | 6 | 6 | 7 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | -2% | 7% |
| Upstream diluent | kgCO$_2$e/bbl of SCO | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| **IHS Markit upstream GHG intensity** | **kgCO$_2$e/bbl of SCO** | **112** | **115** | **108** | **104** | **110** | **105** | **105** | **97** | **92** | **91** | **88** | **90** | **90** | **89** | **87** | **87** | **87** | **86** | **83** | **83** | **82** | **82** | **82** | **-18%** | **-10%** |
| **Mined dilbit (PFT)** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Natural gas | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 50 | 28 | 25 | 25 | 24 | 27 | 22 | 22 | 21 | 21 | 21 | 21 | 21 | 20 | 20 | 18 | 18 | 17 | | -27% |
| Produced gas | kgCO$_2$e/bbl of dilbit | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Petroleum coke | kgCO$_2$e/bbl of dilbit | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Mobile mine fleet | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 10 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | | -13% |
| Fugitives, venting, and flaring | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 8 | 3 | 1 | 1 | 1 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | 3% |
| Carbon capture | kgCO$_2$e/bbl of dilbit | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |
| Electrical balance (import/export) | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 15 | 8 | 5 | 5 | 5 | -1 | 1 | 1 | 1 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | | -73% |
| Upstream natural gas production | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 8 | 4 | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | | -27% |
| Upstream diluent | kgCO$_2$e/bbl of dilbit | - | - | - | - | - | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | | 3% |
| **IHS Markit upstream GHG intensity** | **kgCO$_2$e/bbl of dilbit** | **0** | **0** | **0** | **0** | **0** | **98** | **57** | **48** | **47** | **46** | **45** | **41** | **41** | **40** | **40** | **40** | **39** | **39** | **38** | **38** | **35** | **35** | **34** | | **-24%** |
| **Mined average** | **Units** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Natural gas | kgCO$_2$e/bbl of product | 41 | 41 | 38 | 35 | 45 | 39 | 39 | 36 | 36 | 36 | 35 | 33 | 33 | 32 | 37 | 38 | 37 | 38 | 37 | 36 | 35 | 35 | 35 | -13% | -2% |
| Produced gas | kgCO$_2$e/bbl of product | 29 | 32 | 31 | 31 | 25 | 33 | 30 | 23 | 19 | 19 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | -34% | -17% |
| Petroleum coke | kgCO$_2$e/bbl of product | 20 | 21 | 17 | 16 | 13 | 10 | 10 | 9 | 8 | 8 | 6 | 6 | 6 | 6 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | -62% | -58% |
| Mobile mine fleet | kgCO$_2$e/bbl of product | 9 | 9 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | -12% | -20% |
| Fugitives, venting, and flaring | kgCO$_2$e/bbl of product | 9 | 8 | 8 | 8 | 10 | 8 | 6 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -46% | -17% |
| Carbon capture | kgCO$_2$e/bbl of product | - | - | - | - | - | - | - | -1 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | | -20% |
| Electrical balance (import/export) | kgCO$_2$e/bbl of product | -4 | -3 | -2 | -1 | 0 | 0 | 0 | 1 | 2 | 2 | 0 | 1 | 1 | 2 | -3 | -3 | -3 | -4 | -4 | -4 | -4 | -4 | -4 | -147% | -356% |
| Upstream natural gas production | kgCO$_2$e/bbl of product | 7 | 6 | 6 | 6 | 7 | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | -9% | -6% |
| Upstream diluent | kgCO$_2$e/bbl of product | - | - | - | - | - | 0 | 1 | 1 | 1 | 1 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | | 79% |
| **IHS Markit upstream GHG intensity** | **kgCO$_2$e/bbl of product** | **112** | **115** | **108** | **104** | **110** | **105** | **101** | **89** | **83** | **83** | **75** | **74** | **74** | **74** | **72** | **72** | **71** | **71** | **69** | **68** | **67** | **67** | **67** | **-26%** | **-20%** |

Source: IHS Markit

Table A-4

## Oil sands SAGD dilbit GHG emission intensity cases by component, 2009–30

| Upper-bound case (more conservative) | Units | Historical 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Forecast 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Percent change, 2008/09–17 | Percent change, 2017–30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural gas | $kgCO_2e$/bbl of dilbit | 62 | 57 | 56 | 55 | 56 | 51 | 50 | 50 | 49 | 47 | 47 | 47 | 47 | 46 | 45 | 43 | 42 | 42 | 40 | 39 | 39 | 38 | -22% | -22% |
| Flaring and fugitives | $kgCO_2e$/bbl of dilbit | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0% | 0% |
| Electrical import/export | $kgCO_2e$/bbl of dilbit | -19 | -15 | -13 | -11 | -12 | -9 | -8 | -6 | -6 | -5 | -4 | -4 | -4 | -4 | -4 | -4 | -4 | -4 | -4 | -4 | -4 | -4 | -70% | -31% |
| Upstream natural gas production | $kgCO_2e$/bbl of dilbit | 12 | 11 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | -22% | -22% |
| Upstream diluent production | $kgCO_2e$/bbl of dilbit | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 0% | 0% |
| Upstream solvent/natural gas production for coinjection | $kgCO_2e$/bbl of dilbit | - | - | - | - | - | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| **IHS Markit upstream GHG intensity** | **$kgCO_2e$/bbl of dilbit** | **66** | **63** | **64** | **65** | **65** | **62** | **62** | **64** | **63** | **62** | **62** | **63** | **62** | **61** | **60** | **58** | **57** | **56** | **54** | **53** | **53** | **52** | **-4%** | **-17%** |
| **Lower-bound case (more aggressive)** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Natural gas combustion | $kgCO_2e$/bbl of dilbit | 62 | 57 | 56 | 55 | 56 | 51 | 50 | 50 | 49 | 47 | 46 | 46 | 46 | 45 | 44 | 42 | 41 | 40 | 38 | 36 | 35 | 34 | -22% | -29% |
| Flaring and fugitives | $kgCO_2e$/bbl of dilbit | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0% | 0% |
| Electrical import/export | $kgCO_2e$/bbl of dilbit | -19 | -15 | -13 | -11 | -12 | -9 | -8 | -6 | -6 | -5 | -4 | -4 | -4 | -5 | -5 | -5 | -5 | -5 | -6 | -5 | -5 | -5 | -70% | -4% |
| Upstream natural gas production | $kgCO_2e$/bbl of dilbit | 12 | 11 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 6 | -22% | -29% |
| Upstream diluent production | $kgCO_2e$/bbl of dilbit | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 0% | 0% |
| Upstream solvent/natural gas production for coinjection | $kgCO_2e$/bbl of dilbit | - | - | - | - | - | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | |
| **IHS Markit upstream GHG intensity** | **$kgCO_2e$/bbl of dilbit** | **66** | **63** | **64** | **65** | **65** | **62** | **62** | **64** | **63** | **62** | **61** | **62** | **60** | **59** | **58** | **56** | **54** | **53** | **50** | **48** | **47** | **46** | **-4%** | **-27%** |

Source: IHS Markit

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Table A-5

## Oil sands CSS dilbit historical GHG emission intensity, 2009–17

| Component | Units | Historical 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Percent change, 2008/09–17 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Natural gas | $kgCO_2e$/bbl of dilbit | 77 | 61 | 54 | 53 | 56 | 58 | 61 | 75 | 76 | -2% |
| Flaring and fugitives | $kgCO_2e$/bbl of dilbit | - | - | - | - | - | - | - | - | - | 0% |
| Electrical import/export | $kgCO_2e$/bbl of dilbit | -5 | -5 | -5 | -5 | -5 | -5 | -7 | -10 | -9 | 83% |
| Upstream natural gas production | $kgCO_2e$/bbl of dilbit | 15 | 11 | 10 | 10 | 10 | 11 | 11 | 14 | 14 | -2% |
| Upstream diluent production | $kgCO_2e$/bbl of dilbit | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 0% |
| **IHS Markit upstream GHG intensity** | **$kgCO_2e$/bbl of dilbit** | **96** | **77** | **69** | **68** | **71** | **73** | **76** | **89** | **90** | **-7%** |

Source: IHS Markit

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# Crude by Rail

## The new logistics of tight oil and oil sands growth

December 2014

ihs.com

**SPECIAL REPORT**

Canadian Oil Sands Dialogue


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## About this report

**Purpose.** The Great Revival in North American crude oil production has occurred so rapidly that pipeline infrastructure has struggled to catch up with supply growth. "Crude by rail" has become a key part of the system to ship oil from producing areas to refineries. As the volume of crude oil moving by rail has increased, so have safety concerns. The US and Canadian governments are responding with new rules to improve safety. This report explores the evolution and outlook for movements of crude by rail in North America; the safety of these movements; and the implications of new policies aimed at enhancing the safety of crude by rail.

**Context.** This report is part of a series from the IHS Canadian Oil Sands Energy Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Participants include representatives from governments, regulators, oil and gas industry, academics, pipeline operators, refiners, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS conducted our own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Ottawa, Ontario, on 3 April 2014 and participant feedback on a draft version of the report. IHS has full editorial control over this report and is solely responsible for the report's content (see the end of the report for a list of participants and the IHS team).

**Structure.** This report has four parts and an appendix:

- Part 1: Introduction
- Part 2: Moving crude by rail
- Part 3: The history and outlook for crude by rail
- Part 4: Safety of moving crude oil by rail
- Part 5: Evolving policy

# Crude by Rail

## The new logistics of tight oil and oil sands growth

### Key implications

Railroad transportation has become an enabler of production growth in North America because pipeline capacity has struggled to catch up. But several accidents have raised safety concerns about the increasing role of “crude by rail.” In response, new safety rules have been proposed that could affect the movement of crude by rail. This report explores the evolution of and outlook for crude by rail in North America, the safety of these movements, and the potential implications of new safety rules.

- **Rail transport has become an enabler of crude oil production growth in North America.** In the absence of sufficient pipeline capacity, increasing volumes of crude have been shipped to market by rail. Since 2009, crude-by-rail shipments have increased from 20,000 barrels per day (b/d) to an anticipated annual average of 1.1 million barrels per day (MMb/d) for 2014—about 9% of North American production.

- **The peaking of crude by rail is linked to production growth and the timing of new pipeline capacity.** IHS expects crude by rail to peak between 2015 and 2016 at approximately 1.5 MMb/d—over 10% of North American production. However, should production growth exceed expectations or pipeline projects encounter delays, crude movements by rail could be higher.

- **Rail is here to stay.** Even with new pipeline capacity, we expect movements of crude by rail to continue—exceeding 900,000 b/d out to 2020. The ability of rail to reach refineries unconnected by pipeline will make rail a key and enduring element of the North American oil transport system.

- **Accidents involving rail transport of hazardous material, which includes ethanol, crude oil, and other materials, have declined since the early 1980s.** Despite a nearly threefold increase in the transport of hazardous materials since 1980, over the past five years (2009–13) accidents in which hazardous material was released were a third of the 1980–85 total.

- **Regulatory changes to improve safety, such as speed reductions and more robust tank cars, may also contribute to greater traffic.** Lower speeds and heavier cars (with lower capacity) could lead to demand for more carloads to transport the same volume of crude. This is contributing to some uncertainty over the availability of tank cars, the cost of crude by rail, and the potential for congestion and capacity impacts.

—December 2014

# Crude by Rail

## The new logistics of tight oil and oil sands growth

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## Part 1: Introduction

Shipments by rail were the dominant form of transport in the early decades of the North American oil industry. [1] However, rail was supplanted by the growth of pipelines. As recently as 2009, rail shipments constituted a very small share of oil transit, delivering just over one-tenth of 1 percent of all crude oil consumed by refineries in North America that year.

But railroads maintained their role as the backbone of the North American economy. They service many sectors, including petrochemicals, agriculture, mining, forestry, overall manufacturing, and consumer goods. On a ton-mile basis, or the distance that freight is moved, rail accounted for two-thirds of all freight movements in the United States in 2012. In 2013, in excess of 2 billion tons of goods were moved by rail in the continental United States.[2]

In 2009, the great revival of American oil production began which, combined with already steadily growing output from Canada, led to immediate and growing needs for capacity to ship more oil. The existing pipeline network was unable to keep pace with production growth, nor was it all well-placed for the new production. The North American rail system offered immediate and flexible capacity along with an extensive network.

In less than five years, the volume of crude shipped on North American railroads has grown tremendously. In 2009, about 20,000 barrels per day (b/d) (12,000 carloads per year) of crude moved by rail.[3] In 2013, over 950,000 b/d (about 540,000 carloads per year) were estimated to have been transported by rail—nearly 9% of North American production. As the volume of crude oil moving by rail has increased, a number of accidents have been reported, increasing safety concerns. In a few of these events, explosions occurred, including a tragic accident in Lac Mégantic, Québec, in July 2013, which claimed the lives of 47 people. These accidents have captured the attention of the public, crude oil producers, railroads, and governments in Canada and the United States.

With even greater movements of crude by rail expected, regulators are seeking ways to enhance the safety of this form of transport. This effort also encompasses ethanol, of which 250,000 b/d (about 390,000 carloads) were shipped by rail in 2013.[4] A number of measures have been proposed on both sides of the border that could affect future movements.

Tight oil and oil sands are referenced throughout this report. For additional background information on these two sources of supply growth, see the text box “Primer: Oil sands and tight oil.”

1. North America is used throughout this report to mean Canada and the United States.

2. Source: US Department of Transportation, “Freight Facts and Figures 2013,” www.ops.fhwa.dot.gov/freight/freight_analysis/nat_freight_stats/docs/13factsfigures/pdfs/fff2013_highres.pdf, accessed 13 November 2014.

3. IHS Transearch North American freight flow database. Data include only movements by rail intersecting the continental United States. Wholly inter-Canadian movements are not captured. For more information see http://www.ihs.com/products/global-insight/industry/commerce-transport/database.aspx.

4. IHS Transearch North American freight flow database.

### Primer: Oil sands and tight oil

The two pillars of the Great Revival of North American crude oil production are US tight oil and the Canadian oil sands.

**US tight oil**

Tight oil is sourced from rocks of low permeability and porosity. Oil is produced by drilling horizontal wells into the rock formations and fracturing them through hydraulic stimulation. This process opens pathways in the rocks that allow hydrocarbons to be recovered.

To date, the most prolific producing tight oil areas have been the Bakken (including the Three Forks) Formation in North Dakota and the Eagle Ford Shale and Permian Basin in Southwest Texas. In 2013 these regions accounted for over 80% of US tight oil production.*

**Canadian oil sands**

Oil sand is a naturally occurring mixture of sand, clay, water, and bitumen. In its natural state, raw bitumen is solid at room temperature and cannot be transported by pipeline. To be transported by pipeline, bitumen must be either blended with lighter hydrocarbons or converted into a light crude oil, called synthetic crude oil (SCO).

- **SCO.** SCO is produced by upgrading bitumen (by either removing carbon or adding hydrogen) from a heavy crude oil into a lighter crude oil. SCO resembles light, sweet crude oil, typically with a density of less than 876 kilograms (kg) per cubic meter (or an API gravity greater than 30°).

- **Bitumen blends.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensate, which is a pentane plus hydrocarbon) into a bitumen blend. The blend density is between 923 and 940 kg per cubic meter (20–22°API), making it comparable to other heavy crudes, such as Mexican Maya. A common bitumen blend is “dilbit”—short for diluted bitumen—which is typically about 70% bitumen and 30% lighter hydrocarbons. Alternative blends known as “railbit” and “neatbit” are increasingly being discussed for rail transport. Railbit is a blend of 12–18% diluent, and neatbit is a nearly pure bitumen product containing about 1–2% diluent.

*Bakken Three Forks Formation extends into Montana and Saskatchewan.

# Part 2: Moving crude by rail

## The components of moving crude by rail from field to refinery

Compared with pipelines, the transport of crude by rail generally involves more parties. For crude by pipeline, these typically include a shipper, which contracts for space on a pipeline; a pipeline operator, which transports the crude; and a receiver, typically a refiner, which takes receipt on the other end. The parties typically involved in the transport of crude by rail are described below and illustrated in Figure 1.

- **Shipper.** Crude oil is transported from the field to a loading terminal by pipeline and/or truck. Shippers can be crude oil producers, refiners, or third-party marketing agents.

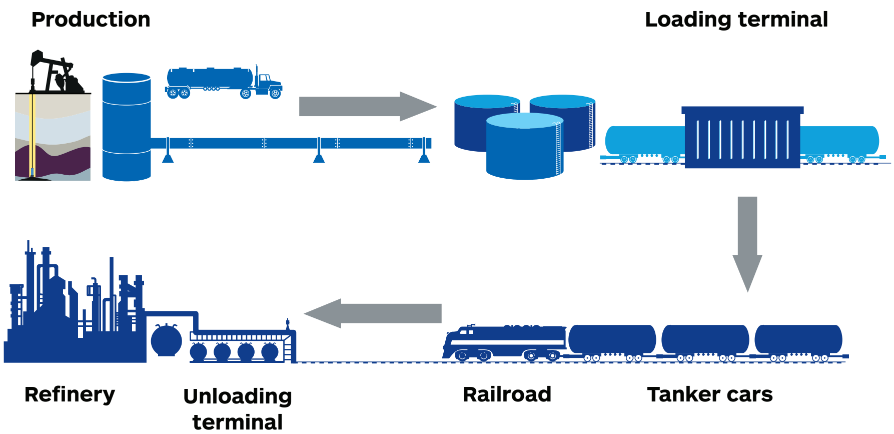
- **Loading/unloading terminals.** Terminal operators are responsible for the proper loading or unloading of tank cars. It is the responsibility of the terminal operator to ensure that crude oil is loaded into appropriate tank cars (in accordance with hazardous material regulations) and that the cars are properly labeled (so first responders are aware of the contents). Crude oil loading terminals are typically owned by third-party companies but can also be owned by producers or refiners.

- **Tank cars.** Tank car owners are responsible for ensuring that their cars meet regulatory standards. About 75% of the cars in North America are owned by third-party leasing companies. Shippers, receivers, and railroads also own tank cars.
- **Railroads.** The railroads are responsible for the safe transport of crude to market. This requires that they ensure that their tracks and equipment are properly maintained.
- **Receiver.** Refiners receive the crude, either directly or from an unloading terminal operated by a third party.

Two key components of crude by rail are the railroads and the tank car. These are discussed below in more detail.

Figure 1

**Components of moving crude by rail**




40326-1
Source: IHS Energy

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## The North American railroads

In North America, freight railway companies are classified as either Class 1 or short-line railroads. Although the distinction is technically based upon revenue, with Class 1 being the larger operation, for simplicity they can be considered as long-haul versus short-haul.[5]

The North American freight rail industry consists of seven Class 1 railways and over 500 short-line operations. Industry operations can be loosely divided by geography. In Canada, there are two transcontinental networks, those of Canadian Pacific Railway (CP) and the Canadian National Railway (CN), as well as over 50 short-line operations. Both CP and CN have significant operations in the United States and therefore qualify as Class 1 on both sides of the border.

In the United States, freight rail is dominated by four large Class 1 rail networks. Two operations are focused in the East—Norfolk Southern and CSX Corporation—and two in the West—Burlington Northern Santa Fe and Union Pacific. Kansas City Southern is the other Class 1 railway in the United States, with a network stretching from the Midwest to the US Gulf Coast (USGC) and farther south into Mexico.

As common carriers, railways have an obligation to respond to all reasonable requests for transport. This obligation provides few rights of refusal, and railroads assume the liability associated with the transport of goods regardless of the risks. In this way, rail must permit the transport of hazardous materials like chlorine—essential for sanitation and clean drinking water—that otherwise may be unable to reach market at a reasonable cost.

## Tank cars

A tank car is a specialized freight car designed for carrying liquids or compressed gases. Tank cars can carry nonhazardous and hazardous goods.[6] Crude and ethanol are considered "hazardous materials" in the United States and "dangerous goods" in Canada.

5. A freight railway operating in Canada is considered Class 1 if it has operating revenues exceeding $250 million. The United States uses the same threshold but adjusts it for inflation every year. For example in 2012, Class 1 railways were those that had revenues in excess of $452.7 million. Source: Canada Transportation Act., Part II Rail Carriers, http://laws-lois.justice.gc.ca/eng/acts/C-10.4/ -- accessed 29 August 2014. Surface Transportation Board, http://www.stb.dot.gov/stb/faqs.html#econ, accessed 29 August 2014.

6. Corn syrup and vegetable oil are examples of nonhazardous goods.

Various tank car designs that differ by their features and intended service are permitted by regulators. These requirements establish a minimum threshold for cars transporting dangerous goods. The design and durability of key features, such as the type and thickness of shell steel, affect the crashworthiness of a tank car and are a source of differences between cars.

The most common tank car specification in North America is the US Department of Transportation 111 (DOT-111). These general purpose tank cars are designed to carry both nonhazardous and hazardous liquids. According to the Railway Supply Institute (RSI), which represents railcar manufacturers, at midyear 2014 DOT-111 cars accounted for 80% of all tank cars in service in North America (about 270,000 out of 330,000 cars).

### Weight and volume limits: Reaching one before the other

Tank cars are both weight and volume restricted. For a given tank car, liquids of different densities can reach one limit before the other. Therefore, tank cars are often purpose-built to the size and weight for the commodity they will handle and directed into dedicated service. For example, a light crude oil, such as tight oil, is most likely to be volume restricted before weight limits are reached. However, the reverse is true for a heavy crude oil, such as oil sands bitumen blends.

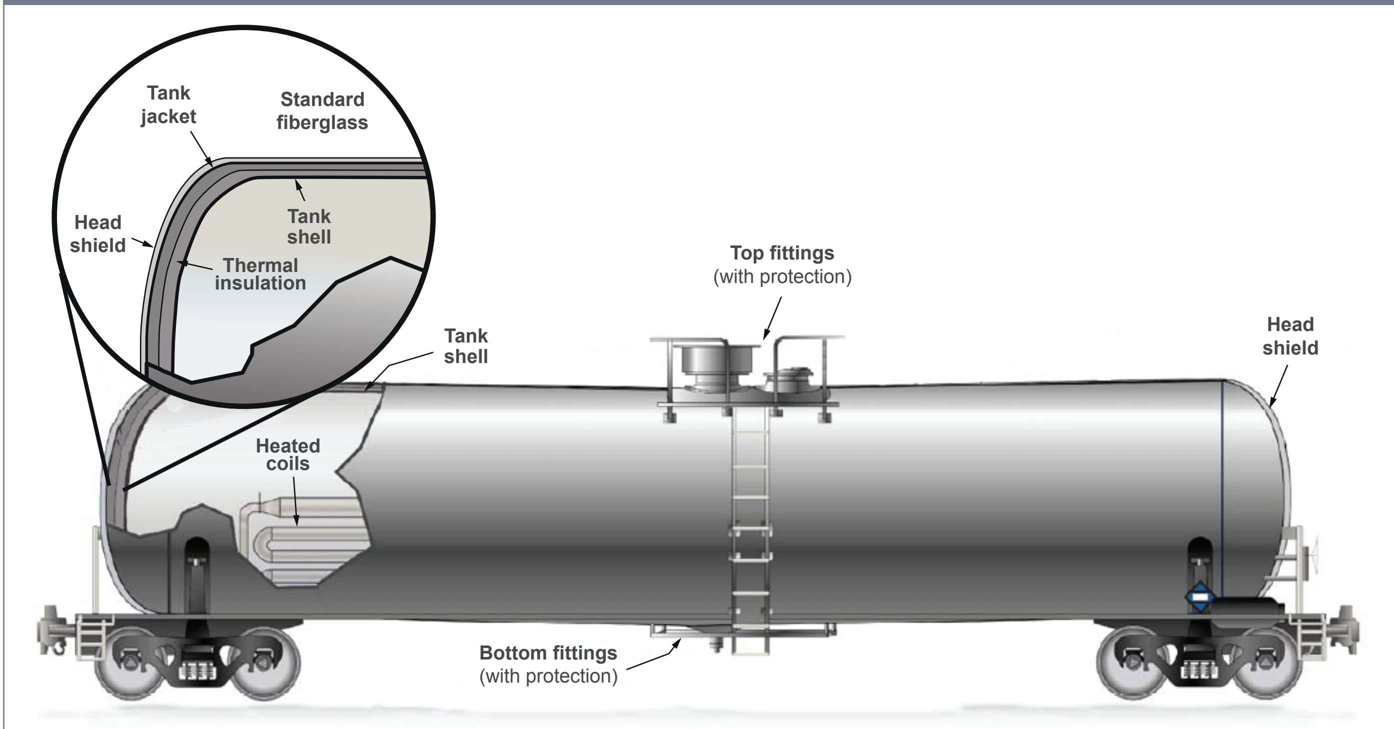
Below is a description, including a depiction shown in Figure 2, of features common to all tank cars, followed by some that have been historically optional. Common features include

- **Tank.** A tank is made up of a shell (the long cylindrical part) with two hemispherical heads (the ends of the tank). Depending on the density of the commodity carried, the capacity of a DOT-111 tank can range from about 10,000 to 34,500 gallons (maximum capacity is around 30,000 gallons for crude oil).

- **Fittings.** Fittings include the equipment that enables the contents to be loaded and unloaded and that can relieve pressure in the event of unplanned pressure buildup while in transit or due to exposure to fire. There are fittings on top

Figure 2

**Components of general purpose North American tank car**




40726-1
Source: Railway Supply Institute

of the shell ("top fittings"), which can be enclosed within a protective housing (a requirement for newer DOT-111 cars). Some cars may also have bottom fittings.

- **Stub sills and couplers.** Stubsills are located on either end of the tank and support the structure. They absorb the forces a railcar is subject to as the train moves along the track. Stubsills are equipped with couplers that connect the tank cars to other cars in the train.

Optional features include

- **Head shields (partial or full).** A tank car may have a partial or full head shield, which deflects or absorbs an impact that otherwise could puncture the head of a tank car.

- **Thermal protection.** In the event of a fire, thermal protection prevents a rapid rise in temperature in the car, which could cause this pressure to build faster than can be vented, compromising the tank car or resulting in an explosion.

- **Jacket.** Jackets (with or without insulation) act as a double hull, absorbing energy in the event of an accident and preventing an unintended release of the cargo.[7]

These optional features have been proposed as mandatory for certain future tank car designs discussed in Part 5 of this report.

## Part 3: The history and outlook for crude by rail

### The Great Revival underpins the rise of crude by rail

The growth of crude by rail is tied to the Great Revival of North American oil production. For decades, North American production had been trending down. Oil sands production began to increase significantly in the early 2000s, but overall North American output was in a long-lasting decline. Starting in 2009, this changed. North American production began to grow again—and rapidly. Rising output in the United States and Canada has backed out offshore imports, and North America is becoming increasing self-reliant in meeting domestic oil demand. Since 2009, North American gross imports of offshore crude oil have fallen by 2.8 MMb/d, to 5 MMb/d in 2014. Production increased 4.4 MMb/d, to 12.4 MMb/d, making North America the largest source of world oil supply growth during this time. Moreover, Canada became by far the largest source of imported oil into the United States.

Historically, North American transportation infrastructure for crude oil was designed to move production and imports to inland markets from coastal regions. In some regions, the Great Revival has led to supply overtaking existing pipeline capacity. To get growing production to market, producers have turned to rail because of its relatively low capital cost and speed to build.[8] In less than five years, crude by rail has increased from a modest 20,000 b/d (12,000 carloads) in 2009 to over 950,000 b/d (about 540,000 carloads) in 2013. By the end of 2014 annual average movements could exceed 1.1 MMb/d—nearly 9% of North American production. In some regions, however, the reliance on rail is much higher. In North Dakota, for example, rail accounts for about 68% of all crude transportation.[9]

Shipping crude oil has become an important part of North American railroad operations—not to mention crucial for US supply growth—delivering not only crude oil to market, but the goods required to support production, such as steel, pipe, and sand. Yet the movement of crude by rail still represented less than 3% of all rail movements by weight (fewer than 2% of all carloads) in 2013.[10]

7. Insulation helps maintain the temperature of the lading (i.e., cargo) in transit.

8. Compared to pipeline that can take several years to develop and bring online, with some pipelines being subject to additional regulatory delay, new rail loading capacity can be brought online in about one year. Source: Gibson Energy and USD completed a rail logistics facility at Hardisty, Alberta. The project was announced on 6 August 2013 and completed on 31 July 2014. See http://usdg.com/media/press-releases.

9. As of August 2014. Source: North Dakota Oil and Gas Division, https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp—accessed October 2014 and North Dakota Pipeline Authority, http://northdakotapipelines.com/rail-transportation, accessed October 2014.

10. Estimate based on revenue freight from the IHS Transearch North American freight flow database.

Uncertainty surrounds the outlook for crude-by-rail volumes in North America. Key areas of uncertainty include the timing of new pipeline capacity; the extent of crude production growth, particularly of tight oil; and regulatory factors. At present, IHS expects North American production growth to continue to outpace new pipeline capacity and the movement of crude by rail to continue to build, although a lower oil price environment could ease the growth of crude by rail.

## *Pipeline capacity the key to the peaking of crude by rail*

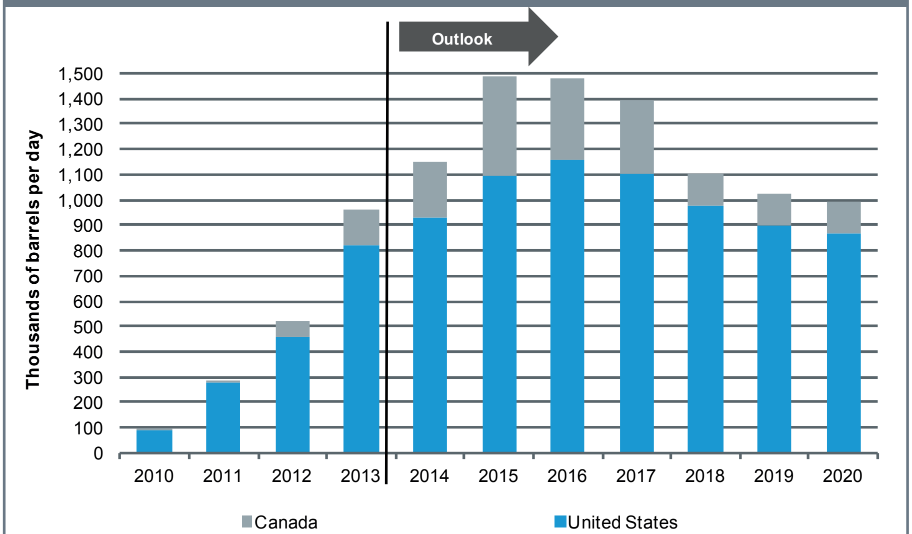
Several large proposed pipeline projects and expansions exiting western Canada and North Dakota could be online in 2016–18.[11] Since moving crude by pipeline is less expensive than moving it by rail, the addition of new pipeline capacity will contribute to the peaking of crude by rail movements between 2015 and 2016 at around 1.5 MMb/d, or over 10% of North American production (see Figure 3). However, should growth be greater than anticipated and/or pipeline projects encounter delays, crude-by-rail movements could peak at a higher level at a later date.

### *North Dakota tight oil growth: A key driver of crude by rail*

Most crude-by-rail movements in North America have occurred in the United States. The majority of these movements have come from production growth in North Dakota. Between 2009 and 2013, Bakken production expanded nearly 500%—from 170,000 b/d to 850,000 b/d—and by the end of 2014 Bakken production is expected to exceed 1.1 MMb/d. With limited access to pipelines and major refining centers some distance away, much of this incremental growth has ended up on the rails. By August 2014, crude by rail departing North Dakota averaged around 765,000 b/d.[12]

Figure 3

Annual average North American crude by rail (thousands of barrels per day)




Source: IHS Energy, IHS Transearch freight flow database, Statistics Canada, and National Energy Board © 2014 IHS

In 2013, just over two-thirds of all North American (or over three-quarters of all US) crude-by-rail movements came from North Dakota. Over half of all movements terminated in the USGC. Fewer movements occurred throughout the United States, with the only other notable source of crude by rail in the lower 48 states coming from growing tight oil production in Texas.[13]

US rail movements are expected to continue to rise largely as a result of growing North Dakota production. However, the destination is shifting from the USGC and toward the East, West, and even the US Midwest. USGC refiners are near the limit of their ability to consume greater quantities of light, sweet crude. Growing production from the Eagle Ford in South Texas and the Permian Basin in West Texas is displacing more distant production from North Dakota. The East Coast market of Canada and the United States is a particularly good fit for North Dakota production. A number of refineries on the East Coast designed to import and run offshore light crudes are not connected to pipelines. In 2014, IHS estimates that these refineries collectively consumed about 1.3 MMb/d of light, sweet crude oil, making them a natural fit for Bakken crude.

11. These include, pending approval where appropriate, expansion of the Canadian mainline, Energy East, Keystone XL, Pony Express Sandpiper, and Trans Mountain Expansion. Northern Gateway obtained regulatory approval in 2014 but has been postponed by Enbridge, anticipated by IHS in 2019.

12. North Dakota Pipeline Authority, Estimated North Dakota Rail Export Volumes, https://ndpipelines.files.wordpress.com/2012/04/nd-rail-estimate-april-2014.jpg, accessed 31 October 2014.

13. Source: IHS Transearch database.

The trajectory of all US crude-by-rail volumes is difficult to predict because inland transportation of crude oil is becoming increasingly complex. Pipeline, rail, barge, and marine tankers will all be leveraged. There is additional uncertainty from the continuing ban on US crude oil exports that could exacerbate imbalances between refinery demand and domestic supply.[14]

IHS currently expects crude-by-rail movements originating in the US to peak between 2015 to 2017, with volumes hovering around 1.1 MMb/d before beginning to subside in 2018 (see Figure 3).[15] This plateau is linked to a combination of planned new pipeline capacity, such as Sandpiper, Pony Express, Keystone XL, Line 9 reversal, and Energy East; completion of new refining capacity in and around North Dakota; and moderation in the pace of production growth. Should production be higher or pipeline projects be delayed, volumes shipped by rail would be higher.

## Western Canada: Crude by rail is just beginning

Production from western Canada is finding its way onto the rails, although the volume is modest compared with the United States. A combination of supply growth and delays in the addition of new pipeline capacity is behind this trend. Western Canadian production, led by the oil sands, has been rising steadily for a number of years. Most existing western Canadian pipeline takeaway capacity transits to the US Midwest. Some of the western Canadian pipeline takeaway capacity is also accessible to North Dakota via cross-border "on-ramps." Combined tight oil and western Canadian supply growth has led to bottlenecks at various stages of the pipeline transportation system. As a result of growing supply and insufficient pipeline takeaway, the price of western Canadian oil has been discounted, sometimes quite severely. For example, Cold Lake Blend, a western Canadian heavy crude oil benchmark, historically traded at a discount of around $20 per barrel (bbl) compared with Brent, a globally traded light crude oil benchmark.[16] But since 2011, the Cold Lake Blend has traded at a discount of about $30/bbl, and at times by as much as $60/bbl compared with Brent.[17] These discounts and the lack of incremental capacity on existing pipelines prompted some producers to turn to rail. As shown in Figure 3, crude-by-rail movements from western Canada are expected to average around 220,000 b/d in 2014—up 80,000 b/d from 2013.

Most Canadian crude that moves by rail is heavy, unlike in the United States where it is mostly light. The largest market for heavy crude oil in North America, by far, is in the USGC region. IHS estimates that the market for Canadian heavy crude oil in the USGC could be up to 1.8 MMb/d.[18] However, as production expands, rail may also provide inland western Canadian production access to offshore markets. For example, in September 2014, nearly three-quarters of a million barrels of western Canadian crude oil were exported to Italy after having been delivered by rail to a port near Montréal, Québec.[19]

Similar to the situation for US crude, movements of Canadian crude by rail could peak in a few years. After averaging about 400,000 b/d in 2015—nearly double the 2014 average—volumes of Canadian crude shipped by rail are linked to timing of new pipeline capacity. Should pipeline proceed as currently proposed, western Canadian movements are anticipated to begin to soften in 2016.[20] Should pipeline projects be delayed, the peak of Canadian crude-by-rail shipments would occur later and at a higher level.

## A look at crude by rail economics: Crude by rail is here to stay

The Great Revival of crude production in North America is expected to provide opportunities for crude to move by rail for many years to come. As shown in Figure 3, even after significant new pipeline capacity comes online, meaningful movements of crude by rail will persist. This section discusses the economics and drivers of the future of crude by rail.

14. See the IHS Special Report *US Crude Oil Export Decision: Assessing the impact of the export ban and free trade on the US economy.*

15. A peaking of US crude-by-rail movements is visible in Figure 3. However this was deemed to be within the range of error with estimated movements in 2015 and 2017.

16. Estimated based on average monthly price Cold Lake Blend at Edmonton, Alberta, and Dated Brent, FOB between 2006 and 2010.

17. Estimate based on average monthly price from 2011 to October 2014.

18. See the IHS Special Report *Future Markets for Oil Sands.*

19. Source: Bloomberg, http://www.bloomberg.com/news/2014-09-24/suncor-looks-east-to-find-buyers-for-western-canada-crude.html, accessed 29 October 2014.

20. Specifically between 2016 to 2018, expansion of the Canadian mainline, Keystone XL, Trans Mountain Expansion, and Energy East are planned to be online.

## Rail economics

Although rail provides producers the flexibility to alter markets from day to day to achieve a higher price for their output, cost and reliability continue to provide pipeline with an economic advantage over rail. Given the option, producers would generally prefer to ship their crude by pipeline. For example, on average it is estimated that rail costs about $8 more to move a barrel of heavy crude blend from western Canada to the USGC compared with pipelines (see Table 1). In addition to a lower cost, the operation of pipelines—unlike railroads—is rarely impeded by weather and other external factors. For example, the estimated average travel time by rail from western Canada to the USGC and back (known as a cycle time) is about 16 to 20 days, but can be up to 30 days.[21] Pipeline transport, for comparison, would average about 23 days (one way) with little variability.[22]

To be sure, the revival of shipping crude by rail is still in the early days. Even over the past few years, the transport of crude by rail has become more efficient. Compared with early 2013, some costs associated with moving crude by rail—including transit times, gathering, and loading—have declined.[23] Use of unit trains over manifest is also leading to lower costs.[24] A unit train can carry more crude and deliver it more rapidly, with less handling (starts, stops, and switching of cars) than a manifest train. Unit trains provide more rapid transit and lower rates from reduced handling. Yet, point-to-point, as shown in Table 1, pipeline continues to have an advantage over rail in terms of cost.

Table 1

**Estimated average transportation cost for rail and pipeline from and to selected markets**

| | | Gathering/ loading | Lease* | Unloading | Transport | Total |
|---|---|---|---|---|---|---|
| Pipeline | Bakken light crude oil to USGC | -- | -- | -- | 10.00 | 9.50 (+/- 1.00) |
| | Western Canada heavy to USGC | -- | -- | -- | 10.50 | 10.50 (+/- 1.00) |
| Rail | Western Canada heavy to USGC | 1.50 | 1.50 | 1.50 | 14.00 | 18.50 (+/- 2.50) |
| | Bakken light crude oil to East Coast | 1.30 | 1.10 | 1.30 | 11.00 | 14.75 (+/- 1.5) |
| | Bakken light crude oil to USGC | 1.30 | 0.90 | 1.30 | 9.50 | 13.00 (+/- 1.5) |

Note: In US dollars. Transportation costs estimated in 2014. All estimates are average values rounded to the nearest decimal point. A most likely range has been provided in the "Total" column; however, considerable variability in crude by rail exists and in some instances cost can exceed even this range. For example at times, and under the right terms and conditions, the rate from western Canada to the USGC can approach $26. Key factors that can affect variability include the rate charged by railroads, tank car capacity, density of crude oil being transported, tank car lease or financing rate, and cycle times (round trip). Tank car lease rates assumed to be $1,500 per month. Estimated average cycle time (round trip) assumed above were 18 days from western Canada to the USGC; 15 days from North Dakota to the US East Coast; and 12 days from North Dakota to USGC. Tank car capacity based on weighted average of existing tank car fleet of 67% DOT-111 and 33% CPC-1232. Tank capacity estimates are 650 barrels for light crude oil, 600 barrels for heavy (dilbit). Additional tank car weight and terminal handling cost was assumed for dilbit transport, as it would likely require special heating capabilities for both railcars and terminals.

Source: IHS Energy © 2014 IHS

As shown in Table 1, the costs of shipping crude by rail include loading and unloading tank cars at rail terminals; leasing or financing tank cars; and charges for transport by the railroad. The IHS estimate of the most likely average value has been provided for each component of transport; however, each input is subject to variability. The most likely range has been provided in the total column; however, in reality the range can exceed what has been shown. For example, if crude by rail requires gathering and transport by truck to rail terminal, loading costs can be as high as $7/bbl. In addition to gathering costs, other factors can affect transport cost. Whether a train is unit or manifest affects the rate charged by railroad; tank car capacity, density of crude oil, and cycle times (round trip) all influence the per-barrel tank car lease/finance estimate. The density of the crude oil can impact terminal loading and unloading handling fees. For these reasons the economics of crude by rail for light, tight oil and heavy oil sands exist over a range and differ.

## The future of rail is going where pipelines do not or cannot go

The ability of railroads to connect producers with remote refiners or to go more readily where pipeline may be challenged to reach will make rail a permanent feature of delivering inland crude (heavy and light) to refiners in North America.

21. Cycle time are impacted by a number of factors, including precise origin and destination, route, seasonality, weather, congestion, and whether train is manifest or unit train.

22. Assumes the completion of Keystone XL, anticipated to be the most direct route to the USGC with crude oil traveling at 5 kilometers per hour over 2,750 kilometers of pipeline.

23. See the IHS Energy Special Report *Keystone XL Pipeline: No material impact on US GHG emissions.*

24. A manifest train transports a variety of cargoes and makes multiple stops to deliver its goods. A unit train is a dedicated nonstop train of one commodity that takes a good from origin to destination and typically consists of 100 to 120 tank cars. Depending on the number of cars, tank car capacity, and density of crude oil, a unit train can transport between 60,000 and 80,000 barrels of crude oil.

A number of refineries in North America built near the coast to access offshore supplies have limited or no access to pipelines. Rail offers these facilities access to growing inland supply, which is expected to continue to be less expensive than offshore imports. A major concentration of facilities that are capable of processing heavy oil sands crudes is located in the USGC region, but additional opportunities may exist for heavy barrels across North America.[25] For light crude oil from North Dakota, the East Coast may provide longer-term opportunities for rail. It could also be particularly challenging to complete new pipelines to connect oil fields in the US Mid-Continent to refiners on the East Coast because the routes would likely need to pass through some of the most densely populated regions in the United States. This provides another longer-term opportunity for rail to transport crude.[26]

### There are unique opportunities to improve the economics of oil sands transport by rail

There are unique opportunities in the Canadian oil sands to improve the cost of transport by rail. Heavy crude from the oil sands is expected to continue to be the largest source of production growth in Canada, and therefore the largest source of crude transported by rail. Rail's ability to move raw bitumen (a pure bitumen-only barrel) from Canada's oil sands is cost advantaged over moving bitumen blends by rail.

The typical oil sands product shipped today is diluted bitumen, or dilbit. Diluent is added to bitumen to allow pipeline transport. Rail has no need for diluent and is capable of moving bitumen-only barrels—the raw undiluted oil sands product. Reduction of diluent can improve the cost of transport via crude by rail for heavy oil sands producers in two ways.

- **Diluent savings.** From a producers' perspective, diluents add cost to shipping bitumen. In fact, condensate, the most common form of diluent, is a premium priced crude oil in Alberta because of demand for bitumen blending. From 2012 to mid-2014, its price has been 25% higher than a barrel of Cold Lake Blend.

- **Transport savings.** Dilbit typically contains about 30% diluent. A reduction in the diluent increases the volume of bitumen that can be shipped and therefore saves capacity in transport.

Limited quantities of conventional heavy oil and pure bitumen from cold flow oil sands production are already being shipped.[27] Production from these facilities does not require the addition of diluent in production and can be moved provided it is warm.

Raw bitumen is not always readily available to ship by rail. Most of the diluent found in the typical dilbit is the result of the extraction process. During extraction, diluent is added to aid in the separation of oil and water and to enhance mobility. Following extraction, more diluent is added to further enhance mobility so as to meet pipeline requirements. Rail transport does not require the additional diluent and can ship the lower diluent blend. This is known as railbit and contains 12–18% diluent per barrel, compared with the typical pipeline dilbit with about 30% diluent.

Removing additional diluent to below production levels requires specialized equipment called a diluent recovery unit (DRU). A DRU can produce a near bitumen-only product, which has become known as neatbit. Neatbit contains about 1–2% diluent. The current cost to operate a DRU is estimated to be about $1/bbl.[28] Some oil sands producers have announced their intention to build DRUs to support their bitumen-by-rail operation.[29] The full cost of moving a barrel of bitumen (i.e., 42 gallons of bitumen) plus the cost of purchasing and transporting the diluent is shown in Table 2. Even

25. Various blends of bitumen can provide opportunities for oil sands across North American.

26. To access eastern refiners, inland crude oil from North Dakota could be transported by pipeline to the USGC region and loaded on marine tanker for transit to refiners along the East Coast. IHS estimates this could be within the same cost range as by rail directly to eastern refiners. However, direct rail involves less handing and therefore less potential complications. Some quantities of crude oil from western Canada and North Dakota are also expected to be able to access eastern markets in Canada and the United States via the Energy East pipeline project and marine tanker at a lower cost than rail.

27. In some parts of the oil sands region, bitumen is less viscous and is extracted without steam.

28. Costs of operating a DRU are influenced by the price of the natural gas used to produce the heat required in the separation of the diluent and bitumen.

29. See MEG Energy 2014 Capital Budget and Guidance, www.megenergy.com/news-room/article/meg-energy-announces-2014-capital-budget-and-guidance, accessed 5 October 2014. See: *Financial Post,* "Cenovus looks to boost oil-by-rail economics," http://business.financialpost.com/2014/02/13/cenovus-looks-to-boost-oil-by-rail-economics/?__lsa=f6cc-6cc3, accessed 5 October 2014.

with the added cost of using a DRU, the cost of rail transport of neatbit is more competitive with pipeline than either dilbit or railbit.

Although pipelines remain cost advantaged, under certain conditions, i.e. a high pipeline cost and low rail cost scenario, the rail transport cost of neatbit could overlap the pipeline transport cost of dilbit. This scenario would require lower railroad rates than the estimates presented in Table 2. A full assessment of relative transportation economics would consider other factors. The price refiners would be willing to pay for the different crude blends is influenced by the marketable products refiners can produce from a given barrel of crude oil. Further, not all refineries may have the necessary configuration or front end infrastructure to handle neatbit and may need to make additional capital investments to run neatbit. In the absence of this refinery investment, the market for neatbit may be smaller than what may be achieved with higher diluent blends. Both of these factors could offset some of the rail transportation savings of neatbit.

Table 2

**Average transport cost per full bitumen-only barrel (42 gallons of bitumen) plus additional diluent (from western Canada to the USGC)**

| | Pipe | Rail | | |
|---|---|---|---|---|
| | | Dilbit (30% diluent | Railbit (15% diluent) | Neatbit (1.5% diluent)[4] |
| Average transport cost per barrel[1] | 10.50 | 18.50 | 18.60 | 18.80 |
| Cost to transport diluent[2] | 3.10 | 5.60 | 2.80 | 0.30 |
| Cost to aquire diluent[3] | 2.40 | 2.40 | 1.20 | 0.10 |
| Other cost (i.e., diluent recovery) | | | | 1.00 |
| Effective cost | 16.00 (+/- 1.25) | 26.50 (+/- 3.25) | 22.60 (+/- 3.00) | 20.25 (+/- 2.50) |

Note: In US dollars. Transportation costs estimated in 2014. All estimates are average values rounded to the nearest decimal point. A most likely range has been provided in the "Effective cost" row; however, considerable variability in crude by rail exists and in some instances cost can be higher than depicted. Refinery valuation of the different blends was not included, nor were potential commercial issues that could impact a producer's decision to pursue these alternative delivery options for bitumen production.
1. Average transport cost drawn from Table 1. For rail transport of railbit and neatbit, additional handling cost was assumed for terminal loading and unloading, and greater density would also impact the per-barrel tank car lease rate.
2. Value of diluent share of transportation space.
3. A simplifying assumption was made that the diluent cost is the arbitrage or difference price between Alberta and the USGC for condensate. Based on 2014 condensate prices by September 2014 this was estimated to be valued around $8.
4. Costs shown for neatbit include only operating costs for diluent and transportation and exclude any capital recovery for DRU facilities. Some heavy oil sands barrels may not require DRU and may reach the loading terminal neat. Assumes neatbit barrel using DRU would contain 1.5% diluent.

Source: IHS Energy



# Part 4: Safety of moving crude oil by rail

Several high-profile accidents have accompanied the growth of crude by rail leading to question about whether this increased transport of crude oil poses greater risk.

This section addresses safety aspects of crude by rail, including which regulatory agencies are involved in overseeing the freight rail safety in North America? How have the frequency of accidents and safety in general changed over time and why? What is the history of hazardous material transport by rail? Do certain crude oils have greater volatility?[30]

## Regulating rail in Canada and the United States

In the United States and Canada, oversight of freight rail is under the jurisdiction of the federal government.[31] Although Canada and the United States regulate freight rail independently, cross-border trade has resulted in symmetry of railroad regulations and operations.

The key federal regulatory agencies involved in freight rail safety in Canada and the United States are

- **Transport Canada.** Transport Canada is responsible for overseeing all railroads crossing provincial and international boundaries in Canada. It has authority over rail operations, track safety, traffic signals, and train control. Transport Canada also regulates the transportation of dangerous goods (i.e., hazardous materials). This includes the proper containment, packaging, placarding, and emergency response requirements.

- **The Department of Transportation (US DOT).** The US DOT is responsible for freight rail operations, including safety and transportation of hazardous materials in the United States. Its responsibilities in this area are divided between two key independent agencies:

30. Volatility refers to how easily a liquid evaporates. Flammable liquids are more combustible in a gaseous state.

31. In Canada, provinces can become involved if a railway operates solely within the confines of one province.

– **Federal Railroad Administration (FRA).** The FRA is principal regulator of freight rail in the United States. It is responsible for overseeing rail operations, track safety, signal and train control, and rolling stock and for enforcing hazardous material regulations.

– **Pipeline and Hazardous Material Safety Administration (PHMSA).** PHMSA has responsibilities for ensuring the safe transport of hazardous materials in the United States. This includes rail.

- **Transportation Safety Boards.** The US National Transportation Safety Board and the Transportation Safety Board (TSB) of Canada are independent transportation accident investigators. Their mandate is to investigate accidents of high public interest and to make recommendations to improve transportation safety. They have no regulatory power.

Other agencies and regulators are also involved in the safe movement of crude by rail in North America. For example, the US Department of Homeland Security is involved in safe route determination and identification of high-risk areas.

## Deregulation transformed the railroad industry and safety

Economic deregulation early in the 1980s renewed investment in rail infrastructure and technology, which increased efficiency, productivity, and safety.[32] Investments led to improvements in track maintenance and equipment, earlier detection of track and equipment issues, and better management of rail operations.

Examples of safety improvements include

- **Equipment.** Stronger, more durable parts and better design have reduced the wear and tear on equipment and lowered failure rates. Freight cars have also been improved. Wheels are now stronger and can bear greater weight. This, in turn, has reduced the number of cars required to move the same volume of goods, lowering the overall wear on rail equipment and infrastructure. More damage-resistant wheels have contributed to lower wheel failures. Locomotives have also benefited from advancements such as dynamic braking. By utilizing the engine as a resistor, friction and wear is reduced on braking systems.

- **Track.** Technology has been deployed on and along tracks for earlier detection of certain track and train equipment defects. Wayside detectors, placed at regular intervals along the track, have become more widespread to identify potential wheel problems. The proliferation of advanced track geometry cars has enhanced early detection of issues related to wear and track design that can impact car and train stability.

- **Rail operations.** Changes to operating procedures have also improved safety. Railways have improved training for operators and introduced antifatigue policies. Also, railways have adopted a systematic approach to risk reduction through safety management systems. By strategically placing engines throughout longer trains (known as distributed power), the wear on wheel, rails, ties, and track ballast have been reduced.

## Crude oil is a hazardous material

Crude oil is categorized as a hazardous material in the United States and a dangerous good in Canada. Hazardous materials are a solid, liquid, or gas that can pose a threat to life and the environment. Gasoline, ethanol, fertilizer, chlorine, hydrochloric acid, and ammonia hydroxide are examples of other hazardous materials.

There are in nine hazard classes, each requiring specific containment, known as packing procedures, and labeling.[33] Crude oil is generally considered a flammable liquid, a Class 3 material. This class is divided into three “packing groups”: Packing Group I (most dangerous), Packing Group II (moderate danger), and Packing Group III (least dangerous). These

32. The Staggers Rail Act in 1980 deregulated large aspects of US railroads by allowing them to set their own rates. In Canada, deregulation gradually occurred from the late 1960s through to the 1980s. One milestone in Canadian deregulation was in 1983, when the Western Grain Transportation Act allowed regulated rates to rise.

33. The nine hazard classes are Class 1: Explosive; Class 2: Gases; Class 3: Flammable liquid; Class 4: Flammable solid; Class 5: Oxidizing agents and organic peroxides; Class 6: Toxic and infectious substances; Class 7: Radioactive; Class 8: Corrosives; Class 9: Miscellaneous.

divisions take into account the flash point and initial boiling point of flammable liquids, such as crude.[34] Most crude oil and ethanol fit into Packing Group II. However, some have argued that given the severity of some accidents that have involved Bakken crude, it should be considered high hazard (Packing Group I). For more information on the factors involved in crude oil volatility, see the text box “Crude oil volatility.”

Regulators require cargoes to be tested and labeled with placards to identify the contents. Placards ensure that first responders follow the correct protocol in the event of an accident. PHMSA has proposed a new sampling and testing program for crude oil that will include information about the testing frequency, methods used, and assurance measures. Similar proposals have been made in Canada.

## Crude oil volatility

To date, all the train accidents in which crude oil has ignited and/or exploded have involved light, sweet Bakken crude oil from North Dakota. This has led to public concerns that Bakken crudes could be more volatile than other crudes.

Like all crude oil, Bakken crude is a mixture of hydrocarbons, including liquefied petroleum gases such as propane and butane, which are more volatile than the heavier components of crude. Oil-producing regions usually have infrastructure that separates lighter hydrocarbons from the heavier ones, typically to meet pipeline specifications. These processes have been less common in the rapidly growing Bakken region than elsewhere, since this equipment is typically associated with pipeline infrastructure (for gathering both gas and liquids, which is less prevalent in the Bakken region). There is a concern that the presence of these lighter hydrocarbons may make Bakken crude relatively more combustible than other crude oils, and the North Dakota Oil and Gas Division is continuing to study this issue. In 2014, studies conducted by both the North Dakota Petroleum Council and PHMSA found Bakken crude oil to be similar in properties to other light crude oils.* ** PHMSA concluded that Bakken crude oil should all be treated as a medium- to high-risk flammable liquid, requiring a minimum of Packing Group I or II. However, North Dakota is continuing to study this issue and recently proposed new rules to require the separation of gases from liquids to help address safety concerns associated with the lighter hydrocarbons in Bakken crude.***

Oil sands crudes may have a lower flammable potential than other crudes. Currently, most oil sands crude production is being shipped as dilbit. Bitumen is very heavy and viscous. It has both a high flash point and a high boiling point. Diluent, typically a natural gas condensate, has both a low flash point and a low boiling point. Because of the diluent, dilbit typically fits into Packing Group II—medium hazard.**** However, the viscosity and flammability of neatbit (nearly pure bitumen) may be sufficiently low that it may not meet the classification as a flammable liquid.*****

*Source: PHMSA, “Operation Safe Deliver,” http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_8A422ABDC16B72E5F166FE34048CCCBFED3B0500/filename/07_23_14_Operation_Safe_Delivery_Report_final_clean.pdf, accessed 29 August 2014.
**Source: Turner Mason & Company for North Dakota Petroleum Council, “Bakken Crude Properties,” http://www.ndoil.org/image/cache/Bakken_Quality_Report.pdf, accessed 31 October 2014.
***See: North Dakota Industrial Commission, “Oil conditioning order: #25417,” https://www.dmr.nd.gov/oilgas/Approved-or25417.pdf, accessed 10 December 2014.
****Source: Cenovus, Specifications for Heavy oil/diluent mix, http://www.cenovus.com/contractor/msds.html, accessed 15 September 2015.
*****Source: Cenovus, Specifications for a bitumen emulsion, http://www.cenovus.com/contractor/msds.html, accessed 15 September 2015.

34. The Transportation of Dangerous Goods Regulations in Canada defines *flash point* as the lowest temperature at which the application of an ignition source causes the vapors of a liquid to ignite near the surface of the liquid or within a test vessel. The flash point can indicate the possible presence of highly volatile (i.e., easily evaporated) and flammable constituents in a relatively nonvolatile or nonflammable material. Source: Transportation Safety Board, 6 July 2014, Analysis of Crude Oil Samples, Montreal, Maine & Atlantic Railway, Train MMA-002, Section 2.2. The initial boiling point at a given pressure is defined as the temperature value when the first bubble of vapor is formed from the liquid mixture. For flammable liquids, defined as liquids with a flash point below 60°C, packing groups are defined as Packing Group I, initial boiling point of 35°C or less at an absolute pressure of 101.3 kilopascals (kPa) and any flash point; Packing Group II, initial boiling point greater than 35°C at an absolute pressure of 101.3 kPa and a flash point less than 23°C; and Packing Group III, if the criteria for inclusion in Packing Group I or II are not met.

## Rail safety statistics in North America

### Subtle differences exist between Canadian and US safety statistics

There are subtle differences between Canada and US rail safety statistics that can make direct comparisons difficult. For example, although an accident is generally defined as an event involving on-track equipment (such as locomotives, railcars, etc.), in the United States damage must exceed a specified threshold to be an accident. Crossings and other incidents, such as trespassing, are often reported separately in the United States. Of the approximately 11,539 accidents and incidents reported in the United States in 2013, only 1,813 were accidents, and the remaining 9,726 involved crossing or other incidents.[35] Where possible we have combined Canadian and US data. Where not possible we refer to US statistics, as it is a much larger market than Canada.[36]

### Train accidents have declined over past decade

From 2004 to 2013, train accidents in Canada and the United States fell 40%, from 4,462 to 2,660.[37] Freight rail accounted for nearly three quarters of these accidents, with the remainder involving passenger trains and railroad equipment.

Accidents on main tracks, which are more likely to be at higher speed and of greater consequence, were also down 40%, from 1,254 in 2004 to 748 in 2013. The most common type of train accident on main tracks is derailments. In 2013, derailments accounted for over 60% of accidents in Canada and the United States. Other accidents arise from collisions (involving another train or an obstruction along the track) and other events such as fire. Accidents can be caused by operational errors, including human error, or problems with equipment and track infrastructure. In 2013, the most common cause of an accident was human error, which accounted for about 40% of accidents.

### Accidents involving the release of hazardous material have decreased

A statistical analysis of safety of crude by rail is difficult to undertake because only limited amounts of crude moved by rail prior to 2009. However, a relevant comparison can be made with accident rates involving hazardous materials. Hazardous material transport has increased in recent years, with 2.4 million carloads moved in 2013—about 8% of all carloads that year.[38]

As shown in Figure 4, although the movement of hazardous materials by rail has nearly tripled since 1980, accidents have declined. For the last five years for which data are available, 2009 to 2013, there were one-third fewer accidents than in 1980–84. In 2013, 19 reported accidents involved a release in the United States, the lowest in recent history. On a North American basis, occurrences have remained fairly stable since 2008, with an average 25–26 events per year. Fatalities from accidents involving hazardous materials have occurred but are not common. According to the Association of American Railroads (AAR), the 47 fatalities from the Lac-Mégantic accident were nearly twice the 24 reported fatalities attributable to hazardous materials in transport by rail in the United States in 1980–2013.[39]

Despite safety improvements by the railroads, there was very little crude oil that had been transported by rail prior to 2009. Between 2006 to early 2014, 13 accidents involving a release of crude oil or ethanol were reported in the United States. Five accidents involved the release of crude oil, which all occurred since 2013. [40] TSB reported five accidents with

35. FRA, Office of Safety Analysis, "Total accidents/incidents, Jan-Dec (2013 preliminary)", http://safetydata.fra.dot.gov/OfficeofSafety/publicsite/summary.aspx, accessed 23 November 2014.

36. Safety-related data is reported to the FRA in the United States and the TSB in Canada. Source: Transportation Safety Board of Canada, "Statistical Summary – Railway Occurrences 2013" and "Rail occurrence data review and follow-up (2014)," http://www.tsb.gc.ca/eng/stats/rail/index.asp—accessed 31 October 2014. Source: FRA Office of Safety Analysis, http://safetydata.fra.dot.gov/OfficeofSafety/Default.aspx, accessed 23 November 2014.

37. Crossing and trespassing accidents have been removed from Canadian data for comparability purposes with US data.

38. Includes only movements within the continental United States.

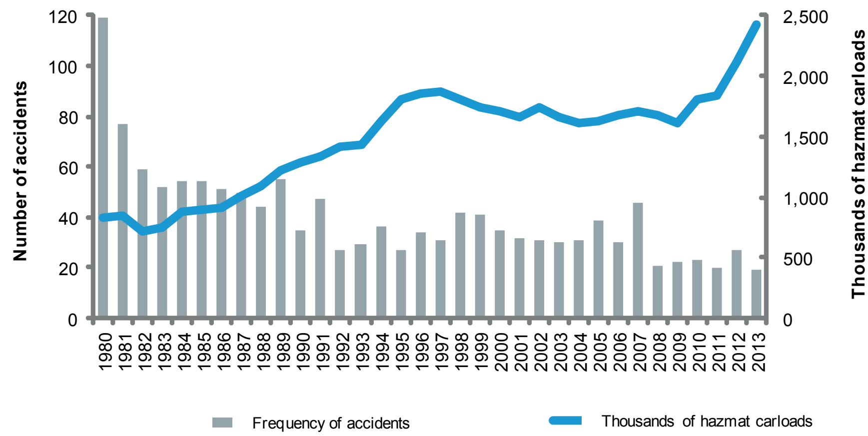
39. US DOT, Pipeline and Hazardous Materials Safety Administration, Hazardous Materials Incident Database.

40. Source: See Federal Register, "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," https://www.federalregister.gov/articles/2014/08/01/2014-17764/hazardous-materials-enhanced-tank-car-standards-and-operational-controls-for-high-hazard-flammable, accessed 28 November 2014.

a release in Canada in 2013.[41] Given the expectation that movements will increase, new policies have been proposed that could lower the risk of accidents involving crude oil.

Figure 4

Hazardous material accidents with a release in United States, 1980–2013




An accident is defined to include the entire train or consist where a release of hazardous materials occured and is not related to the number of cars inovlved in the releae.
Source: FRA, RR Safety Statistics Annual Report, 1997-2010, Table 6-1. FRA Accident/Incident Bulletin, 1980-1996, Table 26. AAR Analysis of FRA Train Accident Database and STB Waybill Sample.



## Part 5: Evolving policy

Efforts by industry and regulators to prevent and mitigate the impact of crude train accidents have intensified. Regulators are introducing new rules to reduce accidents involving crude (and ethanol) trains and to make tank cars more robust in the event of an accident. These measures are expected to lead to safer transport, but they may also contribute to increase transit times and reduce tank car capacity, both which could affect the capacity and cost of crude-by-rail transport. Ultimately the impact depends on the final rules enacted and the railroads' ability to increase efficiency. This section explores how areas of evolving rail policy could affect the movement of crude by rail in North America.

### Speed restrictions lower risk, increase cycle time, and contribute to greater traffic

Regulators in Canada and the United States have proposed rules to reduce accidents involving crude (and ethanol) trains. In July 2014, the US DOT proposed rules aimed at preventing and mitigating the damage of accidents involving trains carrying large volumes of crude.[42] These rules include those related to rail operations, such as speed limits, the use of routing analysis, and adoption of advanced braking systems. These rules impact trains consisting of at least 20 cars carrying crude, referred to as "key" crude trains.

- **Speed limits.** Generally, train speed are related to track quality, geometry (shape, curvature, etc.), and location (e.g., lower speeds in urban areas). Under the proposed new rules, key crude trains may be required to travel at 50 mph (or less). PHMSA is currently considering three options requiring slower speeds for trains that have at least one car carrying crude that is built to older DOT-111 specifications.[43] Trains using older tank cars may face speed limitations of 40 mph in all areas; in areas classified as "high threat urban areas" (HTUA); or in areas with a population of more than 100,000.[44]

- **Routing analysis.** The operators of key crude trains are required to conduct an annual analysis of the routes that the train will travel in order to minimize safety and security risks. The analysis must take into account 27 factors, including the type of track and the population density and capability of emergency responders along the route.

41. TSB, "Statistical Summary – Railway Occurrences 2013," http://www.bst-tsb.gc.ca/eng/stats/rail/2013/ssro-2013.asp," accessed 28 November 2014.

42. See Federal Register, "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains." https://www.federalregister.gov/articles/2014/08/01/2014-17764/hazardous-materials-enhanced-tank-car-standards-and-operational-controls-for-high-hazard-flammable.

43. Tank car specifications are discussed in the next section.

44. The DOT considers a HTUA "an area comprising one or more cities and surrounding areas including a 10-mile buffer zone."

- **Advanced braking systems.** Key crude trains are required to be equipped with one of three types of advanced braking systems (electronic controlled pneumatic brakes [ECP], a two-way end of train device [EOT], or distributed power [DP] locomotives).[45]

Transport Canada has proposed rules in Canada that appear to be moving in a similar direction. In April 2014, Transport Canada ordered rail companies to formulate rules that, at a minimum, require that key trains carrying dangerous goods travel at less than 50 mph, and at less than 40 mph for trains that include at least one DOT-111 car carrying crude oil through areas identified as higher risk. In the same order, Transport Canada also directed rail companies to conduct an initial risk assessment of routes traversed by key trains carrying dangerous goods and to update the assessment periodically. The department also ordered wayside detectors that sense defective railcar equipment to be placed along major routes covered by key trains.[46]

Before the US DOT and Transport Canada released the proposed rules described above, the rail industry committed to taking a number of steps in these areas and others to improve the safety of trains carrying crude. AAR members (which include both of Canada's two Class 1 railroads) committed to limit all key crude trains to 50 mph by July 2014 and those with at least one DOT-111 car or those traveling through a HTUA to 40 mph; conduct routing analysis for key crude trains; and ensure that all key crude trains traveling main tracks have either DP locomotives or EOT devices. AAR also pledged to perform at least one additional track inspection each year than is currently required by law and to install more wayside detectors.[47]

### Implications of stricter rail operational safety standards for oil industry

Regulators have not finalized the new rules aimed at increasing the operational safety of crude by rail. But it is quite likely that lower speed limits could prevail in at least some areas, particularly for trains operating with older style tank cars. Although speed limitations could reduce the likelihood and severity of derailments, it could also contribute to longer transit or cycle times. Over a fixed period, more trains and associated equipment such as locomotives, crews, and tank cars could be required to transport the same volume of crude. This may also impact railroad capacity, as valuable train equipment, such as locomotives and crews, may be required to support the increase in traffic. This could be exacerbated if other trains are delayed behind slower-moving crude trains.

Longer cycle times and more trains (and tank cars) could contribute to greater cost. Ultimately the extent of the impact depends on the final rule chosen, including a proposed new tank car standard, discussed below. The degree to which any cost impact could be moderated by further efficiencies in the transport of crude by rail is discussed in Part 3 of this report.

## More robust tank cars are stronger, heavier, and have lower capacity

Regulators in Canada and the United States are proposing to phase out the older style tank car, known as the DOT-111 (this includes the most recent DOT-111 design known as CPC-1232 or TP14877 in Canada), and to require an enhanced standard for new tank cars built specifically to carry crude oil and ethanol, dubbed the DOT-117 (or TC-140 in Canada).[48]

The older DOT-111 cars face an uncertain future. They may be scrapped, repurposed to other service, or modified to meet the new standard. As for their replacement, various designs for a new, purpose-built tank car have different costs and capacity and thus would impact tank car demand and availability in different ways. If a tank car shortage were to result,

45. These braking technologies or locomotive placements (DP) along the train assist in more rapid deceleration.

46. See Transport Canada, "Minister of Transport Order Pursuant to Section 19 of the Railway Safety Act." http://www.tc.gc.ca/eng/mediaroom/ministerial-order-railway-7491.html.

47. For additional actions taken by the AAR see www.aar.org/Fact%20Sheets/Safety/CBR%20One%20Year%20Later%20Fact%20Sheet.pdf.

48. See Federal Register, "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," https://www.federalregister.gov/articles/2014/08/01/2014-17764/hazardous-materials-enhanced-tank-car-standards-and-operational-controls-for-high-hazard-flammable; and Transport Canada, "Consultations on proposed amendments to the transportation of dangerous goods regulations," http://www.tc.gc.ca/eng/tdg/clear-modifications-menu-261.htm.

crude oil producers could have difficulty in moving their product to market and crude price discounts could result. An inability to deliver ethanol to market could affect the market for ethanol and, subsequently, retail gasoline prices.[49]

### The existing North American tank car fleet

The Canadian and US governments have announced plans to phase out 72,000 tank cars currently in crude and ethanol service.[50] There are two tank cars currently used in the transport of crude and ethanol in North America: the older style DOT-111 and the more recent DOT-111 design (the CPC-1232).

- **DOT-111—the workhorse of the North American tank car fleet.** DOT-111 cars are a nonpressure general-purpose tank car designed to carry liquids, both hazardous and nonhazardous. Because of its versatility, the DOT-111 has been the workhorse of the North American tank car fleet, accounting for four out of five tank cars (or 270,000 out of 330,000 tank cars).[51] About one-fifth of the 270,000 DOT-111s are used to carry crude and ethanol (roughly half and half) (see Table 3). The DOT-111 comes in a range of sizes up to about 30,000 gallons and is weight restricted to 263,000 pounds (lbs) (inclusive of the weight of the car [known as tare weight]).
- **CPC-1232—a DOT-111 with several upgrades and greater weight capacity.** The CPC-1232 (TP14877 in Canada) is a newer design DOT-111 that has been built since November 2011. It comes in various sizes up to about 30,000 gallons and has a greater maximum load than the older style DOT-111, 286,000 lbs.[52] For higher-density liquids, such as heavy crude oil, a greater weight capacity improves the economics of the tank car, requiring fewer cars for a fixed quantity of goods. Also, the CPC-1232 has a number of safety improvements over older style DOT-111s, such as partial head shields, insulation, and top fitting protection.

Table 3

North American crude oil and ethonal tank car fleet, June 2014

| | Crude oil | Ethanol | Total |
|---|---|---|---|
| DOT-111 | 28,300 | 29,300 | 57,600 |
| DOT-111 (jacketed) | 5,500 | 100 | 5,600 |
| DOT-111 (non-jacketed) | 22,800 | 29,200 | 52,000 |
| CPC-1232 | 14,250 | 480 | 14,730 |
| CPC-1232 (jacketed) (7/16th) | 4,850 | 0 | 4,850 |
| CPC-1232 (non-jacketed) (1/2") | 9,400 | 480 | 9,880 |
| **Total tank cars by service** | **42,550** | **29,780** | **72,330** |

Source: RSI, 14 June 2014 © 2014 IHS

### The United States and Canada are currently pursuing separate phaseout schedules

Phase out of the existing tank car fleet, shown in Table 3, is expected to begin in 2017. The United States and Canada are currently pursuing separate phaseout schedules, shown in Figure 5. In Canada, the use of DOT-111 for crude and ethanol service must cease by May 2017, leaving just those cars built since November 2011 (the CPC-1232 and the DOT-117). The United States has proposed phasing out all DOT-111, including CPC-1232, for crude and ethanol service by packing group beginning in October 2017 for goods classified in Packing Group I (high hazard goods). The phaseout of Packing Group II, where most crude and ethanol fit, is expected in October 2018.

The transport of crude oil across the Canada-US border will be required to comply with the most stringent regulations (in other words, the earliest phaseout) of the two nations. As shown in Figure 5, this could equate to the phaseout of DOT-111 in May of 2017 in Canada, and then the phaseout of CPC-1232 in October 2018 in the United States (assuming Packing Group II). This could have implications for cross-border trade. However, Canada and the United States may yet harmonize their phaseout schedules.

49. Both the United States and Canada have renewable fuels standards that mandate a specified volume of ethanol in the gasoline.

50. Source: RSI, 14 June 2014.

51. Source: PHMSA/FRA, DOT, Notice of proposed rulemaking, "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," RIN 2137-AE91, July 2014.

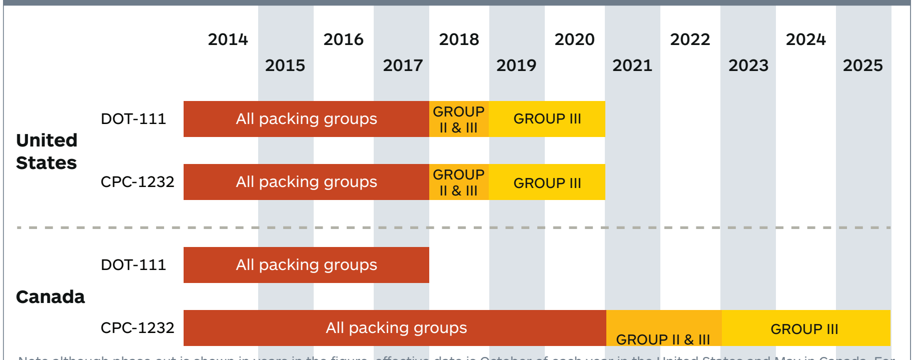
52. Until 2011, freight cars were weight limited to 263,000 lbs. Advancements in stronger wheel assemblies led regulators to permit heavier tank cars. Under certain specifications the maximum permissible load increased from 263,000 lbs to 286,000 lbs in 2011. This contributed to the development of the CPC-1232 design. The CPC-1232 meets or exceeds DOT-111 standards and was sanctioned by the AAR in November 2011.

### The phaseout of the existing crude and ethanol fleet is not without cost

The phaseout of older tank cars at a time when they are already in high demand to meet rising crude-by-rail transport may place even greater upward pressure on tank car prices. Following the phaseout dates, existing tank cars will either be scrapped, repurposed to another service (non-crude oil and ethanol service), or upgraded to the new standard. For shippers, the first two options are equivalent in the sense that they effectively remove the car from crude and ethanol service.

Figure 5

**Canada and United States proposed tank car phaseout schedule: Permitted use of DOT-111 and CPC-1232 for crude and ethanol transport by Packing Groups I, II, and III over time**




Note although phase out is shown in years in the figure, effective date is October of each year in the United States and May in Canada. For example, use of DOT-111 and CPC-1232 would be permitted for Packing Group II materials until October 2018 in the United States.
41226-1
Source: IHS Energy
© 2014 IHS

The timing of the phaseout, tank car manufacturing capacity, and the extent that existing cars can be modified will influence availability and tank car prices. Already over 72,000 tank cars in crude and ethanol service may need some degree of modification under the proposed rules (see Table 3). RSI has expressed concern that the schedule proposed by PHMSA earlier this year could result in a tank car shortage. In addition to the time it could take to clear backlogs or retool facilities to a new standard, RSI estimates that tank car manufacturing capacity may be capable of delivering about 20,000 new tank cars and modifying about 5,000 tank cars per year (depending on labor, shop availability, and the complexity of the modifications).[53] With tank car demand rising, and the initial stage of the phaseout in 2017, tank car supply could tighten, with cost implications for crude by rail.

### The more robust the tank car, the greater the impact on tank car demand

The US DOT announced on 23 July 2014 that it was seeking comments within 60 days on design proposals for the DOT-117. The DOT has proposed three options: the enhanced CPC-1232 (hereafter referred to as CPC-1232+), AAR 2014, and PHMSA/FRA 2014 (see Table 4).[54] The CPC-1232+ is essentially the jacketed CPC-1232 with enhanced top and bottom valve protection. The AAR 2014 and PHMSA/FRA build on the CPC-1232+ design with thicker shells (9/16-inch steel). PHMSA/FRA mirrors the AAR 2014 design with the addition of a stronger, rollover-resistant top fitting protection and Electrically Controlled Pneumatic (ECP) brakes. Transport Canada also proposed a new standard for a crude-carrying tank car, dubbed the TC-140. The TC-140 closely aligns with the PHMSA/FRA designed DOT-117, shown in Table 4.[55] Final decision on the future tank car standards is expected in early 2015.

While all three DOT-117 tank cars feature various safety enhancements over their predecessors, the increased resilience among the options being considered will mean greater tare weight and thus lower capacity. Compared with older style DOT-111 built prior to 2011, both the CPC-1232 and DOT-117 have a higher weight limit of 286,000 lbs (including the tare weight of the car), and thus greater capacity, as shown in Table 4. The phaseout of the lower-capacity older style DOT-111, which made up approximately 67% of the existing fleet in mid-2014, could reduce the number of cars required to move an equivalent volume of crude oil (see Table 3).

However, there are potential trade-offs among the various options being considered as the future crude and ethanol tank car. The key difference is the increase in weight between the steel requirements of the various standards. We estimate

53. Source: Railway Supply Institute, Committee on Tank Cars—Comments on PHMSA Proposed Rule: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains, www.regulations.gov/#!documentDetail;D=PHMSA-2012-0082-2279, accessed 13 November 2014.

54. US Department of Transport, Pipeline and Hazardous Material Safety Administration, Notice of Proposed Rule Making on Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable, July 23, 2014, Posted to Federal Registry, August 1, 2014 http://www.gpo.gov/fdsys/pkg/FR-2014-08-01/pdf/2014-17764.pdf.

55. Transport Canada, http://www.tc.gc.ca/eng/tdg/clear-modifications-menu-1193.html, 23 July 2014.

Table 4

**Comparison of existing and proposed North American tank car standards for crude oil and ethanol rail transport**

| Tank car specifications | Key differentiating features | | | | | | | | Capacity in barrels | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Head shield | Thermal protection | Jacketed | Shell thickness (inches) | Top-fitting protection | Rollover-resistant top fitting | Bottom outlet valve protection | ECP breaks | Bakken (API 40)[1] | Oil sands (API 22)[1] |
| DOT-111 (pre 2011) | | | | 7/16 | | | | | 675 | 580 |
| CPC-1232 (post 2011) | | | | | | | | | | |
| Jacketed | half | ✓ | ✓ | 7/16 | ✓ | | | | 710 | 630 |
| Non-jacketed | half | | | 1/2 | ✓ | | | | 710 | n/a |
| DOT-117 (proposed) | | | | | | | | | | |
| CPC-1232+ | full | ✓ | ✓ | 7/16 | ✓ | | impact resistant | | 640 | 630 |
| AAR 2014 | full | ✓ | ✓ | 9/16 | ✓ | | impact resistant | | 686 | 617 |
| PHMSA/FRA 2014 | full | ✓ | ✓ | 9/16 | ✓ | ✓ | impact resistant | ✓ | 686 | 617 |

1. Tank car assumed to be 30,000 gallons with 1% outage for all standards used for Bakken crude oil and the DOT-111 for oil sands (dilbit). All other oil sands tank cars assumes 26,000 gallons with heated coils and insulation. Because insulation typically comes with a jacket, no value is provided for non-jacketed oil sands capacity.

Source: IHS Energy and Department of Transport, Pipeline and Hazardous Material Safety Administration, Notice of Proposed Rule Making on Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable, 23 July 2014, Posted to Federal Registry, 1 August 2014 http://www.gpo.gov/fdsys/pkg/FR-2014-08-01/pdf/2014-17764.pdf.



the difference between the 7/16-inch steel option and the 9/16-inch steel option to be about 16 bbl per car (for the difference between CPC-1232 and CPC-1232+, and the AAR 2014 and PHMSA/FRA options, see Table 4.) This is relatively minor yet could result in a greater number of carloads between them. For example, if all the crude in 2013 were moved in 9/16-inch cars instead of 7/16-inch cars, 15,000 additional carloads could have resulted—or 2.75% more. Thus, the heavier DOT-117 option could drive greater tank car demand, traffic, and cost than the lighter cars.

## Implications of heavier, more robust tank cars for crude by rail

The phaseout of the existing tank car fleet has implications not only for the cost of crude by rail, but also for the availability of tank cars in North America. The pace of the phaseout and the standard chosen will affect the ability of tank car manufacturers and modification shops to meet demand. However, it is safe to assume the phaseout will not be without cost. From the perspective of the shippers (crude and ethanol producers), it is uncertain who will bear these costs (whether tank car owners, shippers or the railroads, or all three to various degrees), as well as does whether additional efficiencies, discussed in Part 3, could offset or even overcome any cost pressures.[56]

56. Railroads could indirectly bear some of the cost by adjusting rates to maintain a desired level of movements.

## Report participants and reviewers

IHS hosted a focus group meeting in Ottawa, Ontario, on 3 April 2014 to provide an opportunity for stakeholders to come together and discuss perspectives on the key issues related to the growing transport of crude by rail in North American. 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 is exclusively responsible for the content of this report.

Alberta Department of Energy

Alberta Innovates—Energy and Environment Solutions

American Petroleum Institute

BP Canada

Canadian Association of Petroleum Producers

Canadian Natural Resources Limited

Canadian Oil Sands Limited

Cenovus Energy Inc.

ConocoPhilips Company

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

Natural Resources Canada

Railway Association of Canada

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

## IHS team

**Kevin Birn,** Director, IHS Energy Insight, leads the IHS Oil Sands Dialogue. His expertise includes energy and climate policy, project economics, transportation logistics, and market fundamentals. Recent research efforts include analysis of the greenhouse gas intensity of oil sands, economic benefits of oil sands development, upgrading economics, and the future markets for oil sands. Prior to joining IHS, Kevin worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada, helping to inform early Canadian oil sands policy. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US Secretary of Energy. Mr. Birn holds undergraduate and graduate degrees in business and economics from the University of Alberta.

**Juan Osuna,** Senior Director, IHS Energy Insight, is part of the North American crude oil markets team and is responsible for the short-term Northern-tier research efforts. His expertise encompasses oil transportation, marketing, and market fundamentals. Mr. Osuna has worked in the energy industry for over 10 years. Prior to joining IHS, Mr. Osuna led one of Enbridge Pipeline's commodity forecasting groups and was also involved in business development activities. Prior to Enbridge, Mr. Osuna was a lead market analyst for a refining supply and trading group, providing fundamental market analysis to support the day-to-day trading and long-term points of view. Mr. Osuna has also held positions at Plains Midstream Canada and ATCO Electric. He holds an undergraduate degree from the Universidad Rafael Urdaneta in Venezuela and graduate degree in Communication from the University of Calgary.

**Carmen Velasquez,** Director, IHS Energy Insight, is part of the North American crude oil markets team and a key IHS oil sands researcher. Her responsibilities include key aspects of IHS oil sands analytical services, including cost, labor demand, production outlook, and project economics. Ms. Velasquez has worked in the energy industry for over 10 years. Her expertise covers fundamentals modeling across the energy spectrum of oil, natural gas, and power. Prior to joining IHS, she was Head of Market Analytics for BP in Asia, based in Singapore, where she was responsible for creating analytics models to support short-term trading research, including refined product price outlooks. Ms. Velasquez also has experience in US and Canadian natural gas and power markets and previously held positions with BP and TransCanada in Houston and Calgary. She holds a BComm from the University of Calgary.

**Jeff Meyer,** Associate Director, IHS Energy Insight, is focused on oil market fundamentals and market developments. He is a regular contributor to the IHS Energy *World Oil Watch* and monthly global crude oil *Market Briefing*. Prior to joining IHS, 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.

**Steven Owens,** Senior Consultant, IHS Economics & Country Risk, has over a decade of experience developing, collecting and analyzing transportation data. Mr. Owens joined Reebie Associates in 2002 as a software analyst and is now a Senior Consultant with IHS, working in its Global Trade and Transportation group. In his current position, he is the operations lead on the IHS Transearch North American freight flow database. His consulting work has included freight flow and infrastructure analysis for regions as small as a port or city and as large as all of North America.

## Malcolm Cairns Consulting

**Malcolm Cairns, PhD,** Principal, Malcolm Cairns Consulting, has in over 35 years of government service been involved in statistical analysis, transport, and railroad issues. Dr. Cairns spent nearly 20 years with the federal government in a variety of positions and departments, including Statistics Canada, the Canadian Transport Commission, the Office of Privatization and Regulatory Affairs, the Grain Transportation Agency, and Transport Canada. In 1994 he joined Canadian Pacific Railway, where he was involved in research and strategic issues. Dr. Cairns retired from Canadian Pacific in 2011 and now consults under the business name Malcolm Cairns Research and Consulting. Since then he has been involved in research relating to the review of the Canada Transportation Act, with competition issues associated with railway mergers, competition among west coast ports for Asian container traffic, potential market and railway developments in Mexico, and the Canadian review of rail freight service. Dr. Cairns is the past President of the Canadian

Transportation Research Forum and has been an active member of the Ottawa Chapter of the Chartered Institute Logistics and Transportation. He is also a former member of the Advisory Board of the North American Center for Trans-border Studies at Arizona State University. Dr. Cairns has a PhD in mathematical statistics from the University of Toronto.

IHS ENERGY

# The Two Pillars: The increasingly integrated US-Canadian oil trade

June 2016

ihs.com

**STRATEGIC REPORT**

Canadian Oil Sands | Special Report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# Contents

## About this report

**Purpose.** The revival of North American crude oil production reduced offshore imports in North America and strengthened energy security. This Special Report compares the integrated oil markets of Canada and the United States and their reliance on offshore imports (or non-Canadian, non-US produced crude oil) over time (graphically by state and province and by heavy and light crudes). An analysis is provided of the contributions and implications of oil sands and tight oil growth to North American energy security.

**Context.** This is part of a series of reports from the IHS Canadian Oil Sands 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.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS has full editorial control over this report and is solely responsible for its content. This report relies on data from the US Energy Information Administration, National Energy Board of Canada, and Statistics Canada, as well as IHS expertise and judgment. Although best efforts are made to align with various sources, some differences may exist which can result in minor variances between values in this report and those from other sources. This report also distinguishes between crude oil imports and crude oil processed by refiners. Imports may include crude oil delivered to the United States or Canada to be stored or reexported and may not be run by domestic refiners. In this report, *offshore imports* refers to non-Canadian and non-US produced crude oil.

**Structure.** This report has four sections.

- Introduction
- The Great Revival in North American oil production: 2009–15
- The increasingly integrated and self-sufficient Canadian and US energy market
- North America to be increasingly energy secure

# The Two Pillars: The increasingly integrated US-Canadian oil trade

## Key implications

The rise in Canadian and US domestic oil production has displaced offshore imports and made North America more self-sufficient and energy secure. In 2009, around the time US crude oil supply growth began to emerge, about half of the crude oil consumed in North America came from offshore sources. In 2015 this had decreased to less than 30%.

- **Oil sands and tight oil may compete for capital, but not markets; they serve distinctive refining sectors.** There have been two pillars of growth in North America—oil sands in Canada and tight oil in the United States. Oil sands production growth targets heavy, sour refineries while tight oil meets light, sweet crude oil demand.

- **The integrated North American oil trade allows Canada and the United States to collectively achieve greater energy security than each could achieve individually.** The US supply growth has come from light, sweet crude oil—a type of crude demanded by Canada's eastern refiners; while Canadian growth has come from heavier crudes—the type demanded by refiners in the US Midwest and US Gulf Coast. From 2009 to 2015, US light, sweet crude exports to Canada increased 400,000 b/d while US imports of Canadian heavy oil—primarily from the oil sands—increased 1.2 MMb/d.

- **Tight oil has displaced most offshore imports of light crude oil, but opportunities remain for greater use of Canadian heavy oil.** US offshore imports (excluding Canadian) of light oil have fallen nearly 75% since 2009—to around 700,000 b/d as of first quarter 2016. However, the United States continues to rely on 2 MMb/d of offshore heavy, sour crude imports of similar quality to the growing volumes from Canada.

# The Two Pillars: The increasingly integrated US-Canadian oil trade

## Introduction

The Great Revival in North American (Canadian and US) oil production has transformed both the continental and the global oil markets. US refining has expanded, Canadian and US oil trade has grown, offshore imports sourced from nations other than Canada and the United States have fallen, and North America has become more energy self-sufficient.

From 2009 to 2015, North American crude oil production increased by more than 5 MMb/d, to over 13 MMb/d. Individually the United States and Canada rank, respectively, as the third and sixth largest producers globally; collectively they would rank first.

Production is expected to decline, as lower prices have hampered investment in new production. IHS expects production volumes could bottom out toward the end of 2016 and early 2017 at around 12.5 MMb/d before beginning to recover with higher prices. This is a reduction from the 2015 high but still well in excess of levels in 2009.

Although there are various sources of supply growth, the two pillars have been the Canadian oil sands and US tight oil. Together they accounted for nearly 95% of the supply growth, with oil sands expanding about 1 MMb/d and US tight oil nearly 4 MMb/d.[1]

Together Canada and the United States consume about 18 MMb/d of crude oil and other liquid hydrocarbons. This demand is met by a combination of Canadian and US produced crude oil, delivered to refiners by pipeline, rail, and barge, and imports delivered by marine tanker from offshore markets.

The distinct nature of oil sands and tight oil growth has contributed to the further integration of the North American oil market and to a greater displacement of offshore imports than could have been achieved by either nation alone. Between 2009 and 2015, cross-border oil trade between Canada and the United States increased 80%—from about 2 MMb/d to nearly 3.6 MMb/d. In the same period, consumption of offshore imports fell by 3.4 MMb/d, displaced by domestic sources. The North American oil market has become increasingly self-reliant and energy secure. In 2009, about half of Canadian and US refinery demand was met by offshore imports. In 2015 nearly three-quarters of this supply was sourced from domestic (North American) sources.

In 2015, Canadian and US trade was worth over half a trillion dollars. Despite the low oil price, energy was worth over $90 billion, with oil accounting for about 60% of this activity. Yet, the potential for even greater trade, integration, and self-sufficiency exists. This report explores the implication of the historic rise in North American crude oil production that has come about since 2009. Where has this growth emerged, what is the impact on oil trade between Canada and the United States, and what is the potential for even greater integration and energy security?

## The Great Revival in North American oil production: 2009–15

North America has undergone a renaissance in crude oil production. In 2009, years of historical decline reversed and growth began to reemerge. From 2009 to 2015, North American supply expanded by over 5 MMb/d—a rise unprecedented in the history of oil markets.

Although there are various contributors, the two pillars were the Canadian oil sands and US tight oil.

Growth in the Canadian oil sands has a long history stretching back nearly half a century. However, it wasn't until after 2001 that a combination of technological advances and an uptick in global oil prices led to an acceleration of growth.[2] Although oil sands extraction was historically dominated by mining operations, in more recent years increasing volumes have come from in-situ, steam assisted operations, which from a production standpoint have more in common with

1. Note that Canadian tight oil production, which is part of the remaining 5% of growth, grew about 200,000 b/d in 2009–15.

2. For more information see the IHS Canadian Oil Sands Dialogue Special Report *Why the Oil Sands? How a remote, complex resource became a pillar of global supply growth.*

conventional oil production. Between 2009 and 2015, Canadian production expanded over 1 MMb/d, with nearly all of this growth coming from the oil sands.[3]

The advent of tight oil is a new phenomenon, but the speed and scale of growth have had no equal in the history of the oil markets. Tight oil is produced from a variety of geological formations of low permeability and porosity (including shales, tight sands, and tight carbonates). These reservoirs were once considered uneconomic, but the advent of horizontal drilling and multistage completion techniques resulted in a dramatic turn in US oil production. After bottoming out in 2008, US crude oil production grew 4.7 MMb/d from 2008 to April 2015, nearly all attributable to tight oil.

Lower prices have reduced activity in new oil production in North America. The longer lead times associated with oil sands production mean that it will continue to grow through the worst of the low oil prices. US tight oil, however, is more price responsive, and production is declining. IHS expects US production may decline toward the end of 2016 into early 2017 around 8.5 MMb/d—back to the level of May 2014, yet still significantly above 2008 levels of around 5 MMb/d. As the market moves out of surplus, higher prices should eventually incentivize new investments in oil production, US supply growth is expected to reemerge, and Canada may maintain its long history of growth.

## Meeting refinery demand takes crude of different quality

Across the continent, refineries process a wide spectrum of crude oil. Neither crude oil nor the refineries that manufacture it into refined products are homogenous. Various crude oil properties affect the cost and refining equipment required to convert the oil into refined products, and subsequently the value and market available to crude oil producers. Facilities designed for one type of crude find it less profitable to process other grades of crude oil—mismatches exist between crudes available and various refining configurations. If a refinery processes a crude that is not optimal for its configuration, it will produce fewer high value refined products. Two key distinguishing traits of crude oils are density and impurities.

- **Density.** In a general sense, less dense or "lighter" crude oils are more easily converted into refined products such as gasoline and diesel. "Heavier" or higher density crudes are more costly to convert into refined products. To process heavier crudes, refiners must make large capital investments in specialized processing units. Additional energy and therefore cost is also required to aid in refining these crudes.

- **Impurities.** Impurities, such as sulfur, must be removed during the refining process to meet product specifications. The higher the content of sulfur (or other impurities), the greater the costs for a refiner to process the crude oil. Low-sulfur crudes (less than 1%) are called "sweet," while high-sulfur crudes are "sour." Sulfur is the most commonly cited impurity, but others exist, such as heavy metals or acids.

The physical characteristics of different crudes have resulted in an array of refineries with varying abilities to process different crude oils. Refineries will value crudes differently, depending on their configuration (their ability to efficiently process different crudes). No two refineries are the same. Heavier, sourer crudes are more costly to refine and as a result trade at a discount to lighter, sweeter crudes. Refiners that have made large capital investments into processing heavy crudes will continue to consume them, while less complex facilities, which are not equipped for handling heavier grades, will seek out lighter feedstock.

Throughout this report we refer to light, medium, and heavy grades of crude oil. Although there are generally held views as to which properties define these categories, there is no hard-and-fast rule. For the definitions used here, see the text box "Crude oil definitions used in this report."

## Oil sands and tight oil are complementary sources of supply

Oil sands and tight oil have been complementary sources of supply. In 2015, North America consumed nearly 18 MMb/d of crude oil. This broke down roughly into 8 MMb/d of light crude and condensate (ultralight), about 5 MMb/d of heavy crudes, and about 4.4 MMb/d of medium grades (or everything in between).

3. Oil sands production includes bitumen upgraded into light synthetic crude oil, and raw bitumen. Diluent used for the creation of bitumen blends and dilbit is not included in the IHS definition of production.

## Crude oil definitions used in this report

There are general categories of crude oil—light, medium, and heavy—as well as key quality indicators, such as sweet or sour. When not expressly stated, such as in figures, the definitions used in this report are as follows:

- **Light crude oil includes low-sulfur (less than 1%) crudes with an American Petroleum Institute (API) gravity greater than 24 degrees (24° API).** These crudes are also often referred to as condensate; light, sweet; and medium, sweet crudes.
- **Medium crude oil is defined as higher-sulfur crudes (greater than 1%) with greater than 24° API.** These crudes are also often called light, sour and medium, sour crudes.
- **Heavy crude oil includes crude oil with higher sulfur content (greater than 1%) and less than 24° API.** Middle Eastern heavy crudes of less than 28° API were included in our definition of heavy crudes. Generally these crudes are referred to as heavy, sour crudes.

Although tight oil and oil sands may compete for capital investment, they are complementary from an oil market perspective. US tight oil, a light crude oil, has predominantly helped meet the demand of light crude oil refiners across North America, whereas oil sands have principally targeted more complex facilities configured toward heavier crude oils.[4]

## The increasingly integrated and self-sufficient Canadian and US energy market

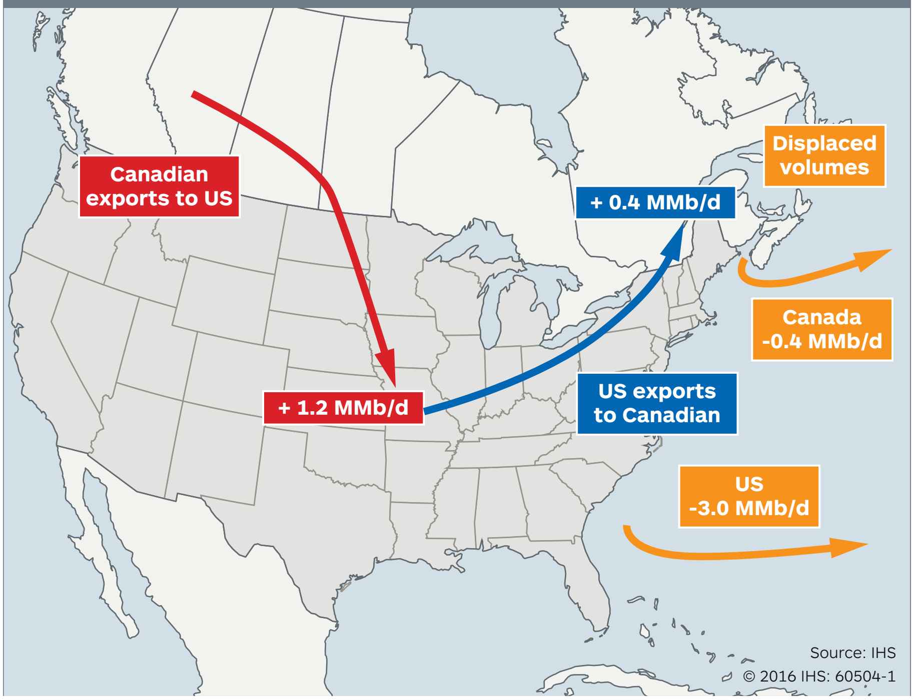
Nearly all of US tight oil and Canadian oil sands growth has found its way into North American refineries, where it has been converted into refined products such as gasoline and diesel.

From 2009 to 2015, the processing of North American sourced crudes expanded 64%—or nearly 5 MMb/d. In a system that consumed about 18 MMb/d in 2015, this is a significant increase. About 3.4 MMb/d of the increase came about as domestic supply displaced offshore imports. About 1.6 MMb/d was made possible from the increased trade of growing Canadian heavy crude supply into the US market and the flow of US light, sweet crude into Canada's eastern regions (see Figure 1).

In 2015, the United States and Canada were each other's single largest source of foreign oil. From 2009 to 2015, US imports of Canadian crude increased nearly 1.2 MMb/d, reaching a record level of 3.1 MMb/d in 2015. Conversely,

Figure 1

North American crude trade flows and displacement of offshore imports (2009–15)




4. Canadian oil sands supply includes both heavy bitumen blends and bitumen upgraded into light synthetic crude oil similar to light, sweet crudes. However, the onslaught of US tight oil diminished the economic incentive to invest in the heavy oil upgrading capacity necessary to convert bitumen into synthetic crude, and growth has been dominated by heavier bitumen blends targeting heavy crude oil refiners.

US exports to Canada expanded 400,000 b/d and in 2015 were also at record levels exceeding 420,000 b/d on an annual average.

Oil trade has taken an increasingly important role in the Canada-US trade relationship, where trade tops half a trillion dollars per year. Energy alone was worth over US$90 billion in 2015, of which oil made up the majority (even in 2015 at depressed oil prices), accounting for 60% of the total energy trade between the countries.[5]

## Traditional markets for Canadian heavy consumed more

Increasing volumes of Canadian imports into the United States have come in the form of growing heavy diluted bitumen blends from the Canadian oil sands. These imports have ended up principally in the US Midwest—the historical home for Canadian exports. In 2009, the Midwest consumed about 1.2 MMb/d of Canadian crude. In 2015 this had risen to over 1.8 MMb/d. States that had traditionally run Canadian heavy crude are running more of it. As Figure 2 shows, states such as Illinois, Indiana, and Minnesota still rely heavily on Canadian supply to fill their refineries. Increasing volumes of Canadian supply—all heavy, sour crudes—have continued to build into the Midwest regions, but volumes are reaching the Texas Gulf Coast region as a result of increased US pipeline connectivity. IHS estimates that deliveries into the Gulf Coast states may have approached 500,000 b/d in 2015, up nearly 400,000 b/d since 2009.

## Greater energy security potential remains from the Canadian oil sands

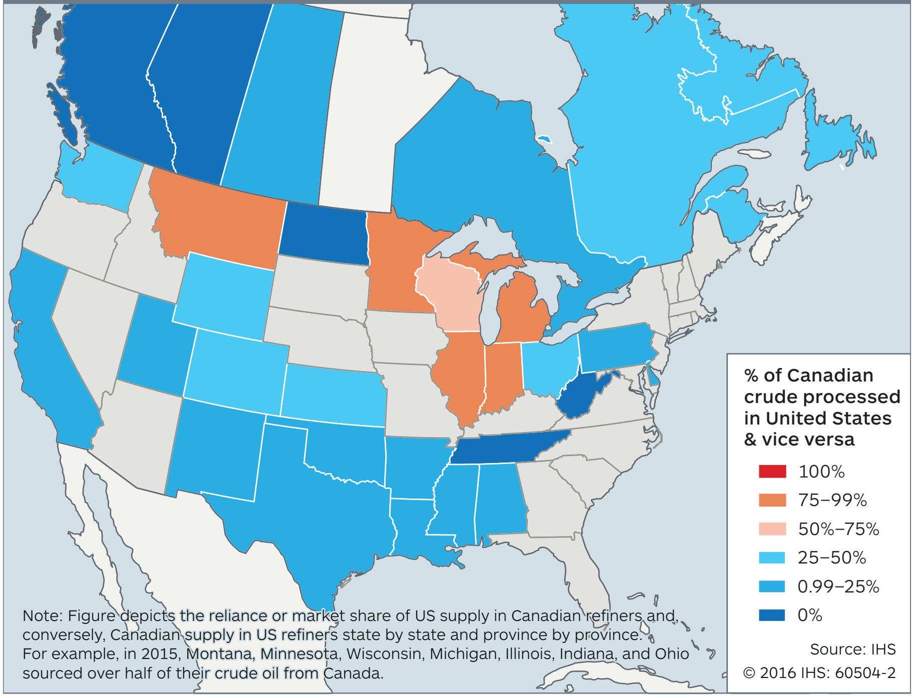
The Canadian oil sands still hold untapped potential to further increase North American energy self-sufficiency. Although tight oil has displaced significant volumes of offshore imports, the impact has been largely restricted to crude oil of similar quality. In 2015, North America still imported significant volumes from offshore sources, including about 2 MMb/d of heavy, sour crude oil of similar quality to the growing supply from the oil sands (see Figure 3). Nearly 90% of these imports arrived into the US Gulf Coast (USGC) region.

As Figure 4 shows, the states that have historically relied on offshore heavy, sour imports remain largely untouched by Canadian supply growth (the exception being Virginia, whose refinery shut down in 2010). Increasing volumes of Canadian crude have begun to move into the USGC, but since the cross-border pipelines are near their current capacity, pipeline flows to the Gulf may be constrained until new upstream capacity is built. A large viable market for Canadian heavy crude remains in the United States, particularly Texas, Louisiana, Mississippi, and Alabama (which together imported nearly 2 MMb/d of heavy crude in 2015, with actual processing capacity being even higher).

Moreover, US heavy oil refineries along the Gulf Coast face an uncertain future from their historical suppliers, Mexico and Venezuela. Mexican production has fallen by over 1 MMb/d over the past decade; and although the drop in

Figure 2

**US and Canadian share of each other's imports**




Note: Figure depicts the reliance or market share of US supply in Canadian refiners and, conversely, Canadian supply in US refiners state by state and province by province. For example, in 2015, Montana, Minnesota, Wisconsin, Michigan, Illinois, Indiana, and Ohio sourced over half of their crude oil from Canada.

Source: IHS

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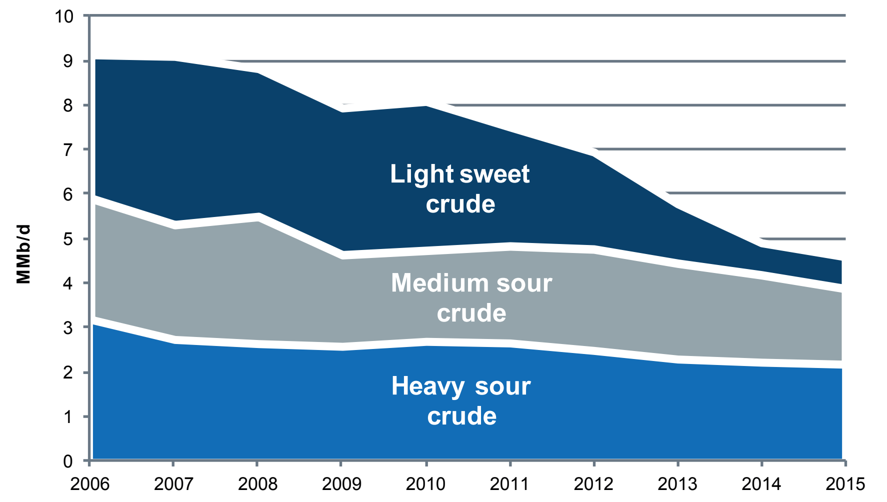
5. Source: U.S. Census.

Venezuela's output has been a more modest 200,000 b/d, the country also faces significant economic challenges that may affect its ability to maintain production levels in the future. In 2015, the United States relied on 1.4 MMb/d in imports from these two nations. Because the USGC is the single largest heavy crude oil processing market in the world, the potential match between Canadian supply and USGC demand remains an attractive pairing—particularly in light of the prospect of reduced access to leading competitive sources of supply from Mexico and Venezuela.

Figure 3

**Canada and US offshore crude oil imports by type (2006–15)**




Source: IHS Energy

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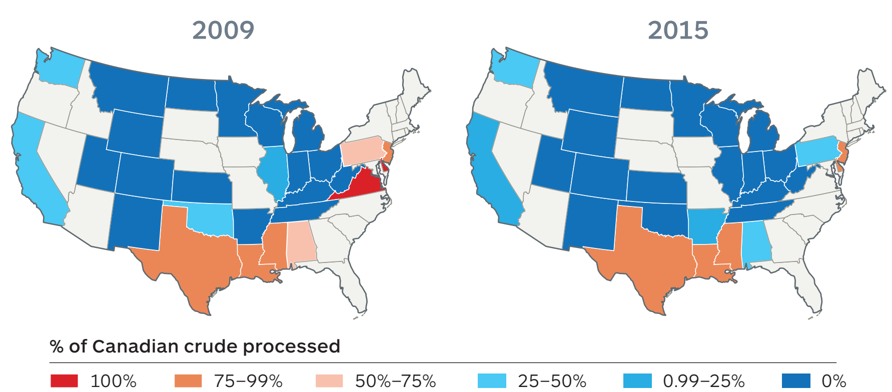
Figure 4

**Change in offshore heavy crude oil imports share of state refinery demand**




Note: Figure shows the share of domestic refinery crude oil consumption of North American sourced crudes and offshore imports of heavy, sour crudes. For example, in 2015, Texas, Louisana, Mississippi, Alabama, New Jersey, and Delaware sourced over half of the heavy crude oil consumed from offshore sources. However, it is silent on volumes; for example, Texas consumed about 1.2 MMb/d of offshore imports in 2015, whereas the entire US East Coast imported about 65,000 b/d.

Source: IHS

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## US tight oil has penetrated all regions, including Canada

US light tight oil has overrun regional demand and displaced foreign imports in the Gulf Coast, Midwest, West Coast, and East Coast, as well as in Canada. Abundant cheap inland crude has also encouraged greater consumption of lighter crudes.

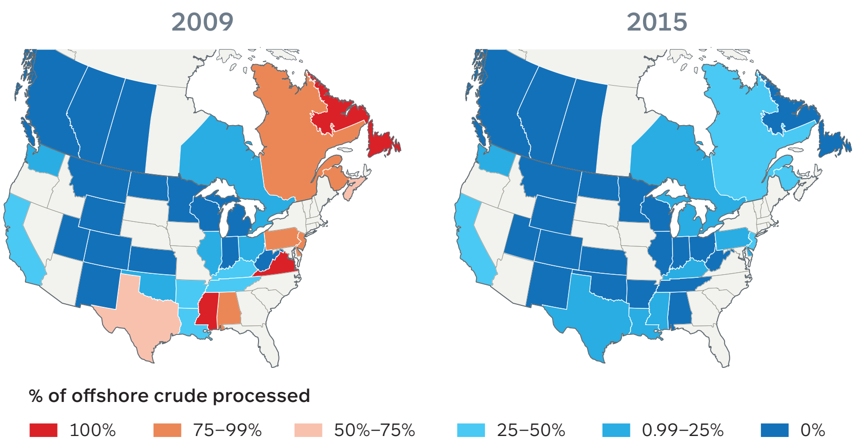
Combined refinery demand for offshore imports of light crude in Canada and the United States fell by around 2.5 MMb/d, from just under 3.2 MMb/d in 2009 to around 700,000 b/d in 2015. Lower prices are reducing US production, and some light barrels will flow back into the United States over the coming months. Light oil imports have already increased by 175,000 b/d since fourth quarter 2015. Yet US offshore imports (excluding Canadian) of light oil remain nearly 75% lower than 2009 levels, at 700,000 b/d as of first quarter 2016. As prices recover, growth will return, and with them US supply may rise again, displacing offshore imports.

As shown in Figure 5, the impact on offshore imports across the United States and Canada has been more pronounced in coastal regions. In 2009, the US East Coast consumed 1.2 MMb/d of offshore imports—over 65% being light crude. Between 2009 and 2015, consumption of offshore imports of light crude oil on the East Coast fell 74%, from 700,000 b/d to about 180,000 b/d, with the greatest impact being felt in Pennsylvania, New Jersey, and Delaware. USGC consumption of domestically sourced light crudes increased from 1.1 MMb/d in 2009 to nearly 3.8 MMb/d in 2015. Stated another way, consumption of light crude oil imports sourced from offshore sources fell from over 1.5 MMb/d in 2009 to 130,000 b/d in 2015. The rise of crude-by-rail has given light, sweet crude from tight oil access to nearly all US markets and Canada's eastern regions.

Canada's refining sector illustrates the similar impact of increased supply, trade, and displacement of light, sweet crude oil imports from offshore sources. Canada's eastern provinces, which are the farthest from the producing areas in western Canada, have historically consumed most of the country's offshore imports. From 2009 to 2015, consumption of offshore imports into eastern Canada fell over 430,000 b/d as a direct result of increased tight oil deliveries (and also because of a reduction in regional refining capacity).[6] In 2009, Quebec and New Brunswick sourced nearly all (90%) of their refinery demand from offshore imports. By 2015 this had fallen to just over 40%—a reduction of nearly 500,000 b/d. In 2009, total US deliveries to all of Canada were a meager 45,000 b/d. In 2015, US volumes exceeded 420,000 b/d—a new record and nearly 30% of Canadian demand.[7] The vast majority of these deliveries were into Canada's eastern regions. These volumes are expected to soften as a result of lower prices and further distance to US supply centers. However, the prospects of increased pipeline connectivity from the western producing regions in Canada and the upper Midwest (home to Bakken production, one of the key regions of US tight oil growth) could enable more economic movements of both Canadian supply and US production into this region.

Figure 5

**Light runs increase consumption and displace offshore imports**




Note: Figure shows the share of Canada- or US-sourced light crude oil consumption by North American refiners versus offshore imports of light crude oil. For example, in 2009, Quebec, Newfoundland, Nova Scotia, New Brunswick, Texas, Mississippi, Alabama, Virgina, Pennsylvania, and New Jersey sourced over half of the light crude oil consumed in those regions from offshore origins. However, it is silent on volumes; for example, Texas consumed about 1 MMb/d of light offshore imports in 2009, whereas Quebec and Altantic Canada consumed about 600,000 b/d in 2009.

Source: IHS
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## North America to be increasingly energy secure

The increase in supply of US tight oil and Canadian oil sands has proven complementary, and the North American energy market has become more integrated as a result. The trade of crude has expanded, enabling a greater displacement of offshore imports than could have been achieved by each nation alone. In 2015, the United States and Canada were each other's largest source of oil imports, with Canada supplying about 20% of US oil demand and the United States supplying nearly 30% of Canadian crude oil consumption.

As supply from both production types—tight oil and oil sands—has increased, each has met the needs of different types of refineries. On the one hand, the enormity of the scale of US tight oil production has allowed it to reach every corner of North America by pipeline, rail, and marine transport, and offshore imports of light crude were decimated. However, the picture is very different for heavier grades of crude oil. Offshore imports of these grades—medium and heavy—are largely unchanged. The persistence of these imports highlights the scale of continental oil consumption as well as the mismatch of US tight oil and refiners' capabilities.

Lower prices will reduce North American supply—predominantly from US tight oil—and some lighter barrels may flow back into the United States and Canada to offset these declines. However, with production declining globally, prices are expected to rise, and with them US production growth will reemerge and Canada may maintain its long history of growth.

6. Canada's reduction in offshore imports was impacted by a reduction of East Coast refining capacity with the conversion of Shell's 130,000 b/d Montreal East refinery to a terminal in 2010, and similarly the conversion of Imperial Oil's 88,000 b/d Dartmouth refinery into a terminal in 2013.

7. In May 2015, US deliveries reached 524,000 b/d.

Growing volumes of Canadian heavy oil could increase North American energy security. IHS expects increasing volumes of Canadian heavy oil to be drawn to the USGC region, where the heavy, sour crudes from the oil sands represent an attractive substitute for declining offshore heavy crude supply from Latin America (primarily Mexico and Venezuela). As volumes increase, North American oil trade—and therefore energy security—could expand further.

## IHS team

**Aaron Brady**, Senior Director, IHS Energy Oil Market Services, has more than 15 years of experience in analysis and forecasting of global and North American oil markets. Mr. Brady has authored numerous IHS reports, including the role of biofuels, the economics of electric vehicles, and peak oil demand in the developed world, along with many regular Market Briefings and World Oil Watch reports. Previously, Mr. Brady was a consultant in the oil industry, focusing on downstream regulatory issues, including the transition to ethanol in the California gasoline market. Mr. Brady holds a Bachelor of Arts from Amherst College, Amherst, Massachusetts, and a master's degree from Johns Hopkins University's Paul H. Nitze School for Advanced International Studies, Washington, DC.

**Kevin Birn,** Director, IHS Energy, leads the IHS Oil Sands Dialogue. His expertise includes energy and climate policy, project economics, transportation logistics, and market fundamentals. His recent research includes analysis of the greenhouse gas intensity of oil sands, economic benefits of oil sands development, upgrading economics, and the future markets for oil sands. Prior to joining IHS, Mr. Birn worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada, helping to inform early Canadian oil sands policy. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US Secretary of Energy. Mr. Birn holds undergraduate and graduate degrees in business and economics from the University of Alberta.

**Peter Kucera**, Research Manager, IHS Energy, manages subscription services covering North American downstream companies and markets and contributes to IHS Energy's downstream and midstream consulting practice. He specializes in North American crude and product markets, midstream infrastructure, and competitive benchmarking. Proficient in French and literate in Russian, Mr. Kucera holds a BS from Georgetown University and a certificate in Russian Studies.

**Dominik Rozwadowski**, IHS Energy Market Research Analyst, North American Oil, supports research efforts for North American crude oil analytics. He contributes to the delivery of market research concerning crude oil supply and demand balances, transportation by pipeline and rail, price forecasts, and geopolitics. Prior to joining IHS, Mr. Rozwadowski worked at the Canadian Energy Pipeline Association, where he collaborated with North American pipeline companies on program development for operational issues related to regulatory reform, the environment, and pipeline safety. Earlier, at Nabors Drilling, he gained field experience at a number of oil and gas fields in northern Canada. Mr. Rozwadowski holds a Bachelor of Commerce degree and a Bachelor of Arts degree from the University of Calgary.

IHS ENERGY

# Where Will Transportation Drive Global Oil (and Oil Sands) Demand?

December 2016

ihs.com

STRATEGIC REPORT

**Kevin Birn**
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Senior Director

**Hossein Safaei**
Associate Director

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# Where Will Transportation Drive Global Oil (and Oil Sands) Demand?

## Key implications

Global oil demand has increased 19 million barrels per day since 2000—a gain of 25%. Accounting for more than half of global liquids demand, growth in transportation fuels, particularly for passenger vehicles such as car and trucks, is a key element of this trend. But will growth continue? Rising fuel economy standards, the prospect of greater electric vehicle sales, and potential shifts in consumer behavior will shape the course of future oil demand and the market for key sources of oil supply like the Canadian oil sands.

- **Many mainstream global energy forecasts expect oil demand to continue to grow over the next two decades.** However, some forecasts see the potential for oil demand to peak within the next 10–20 years. Uncertainty about future oil demand is growing due in part to the potential for dramatic changes in the transportation sector.

- **Transitions typically take time, and the long life of the existing on-road fleet means that the impact of new vehicles on global oil demand will likely be gradual.** In 2016, 96% of new vehicle sales featured combustion engines. IHS estimates average vehicle life globally to be about 15 years. This is critical as it means the impact of new vehicle technologies takes time to materially affect the vehicle fleet and overall fuel demand.

- **Indeed, the future of the car—and the sources of energy that propel it—is not predetermined.** There are downside risks that could see oil demand peak or reach new heights. A different mix of policy, changes in consumer behavior, new technologies, and economic growth could lead to different outcomes. Moreover, the effects of new mobility business models, such as ride-hailing, and emerging technologies, such as autonomous vehicles, are not yet fully understood.

- **Even with slower or even flat world oil demand, significant investments in upstream production are needed to maintain supply levels.** The world needs to find and replace about 45 million barrels per day of crude oil by 2040 (or about half of what the world consumed in 2016): 37 million barrels per day will be needed to offset production from declining fields while 8 million barrels per day will be needed to meet demand growth.

- **The Canadian oil sands are likely to remain an important part of meeting global oil demand.** Unlike most other sources of oil supply globally, production from oil sands facilities does not decline in the short term. This means new investments in oil sands production have a more pronounced effect on supply growth. Oil sands production has the potential to reach 3.9 MMb/d in 2030—a 1.5 MMb/d increase from 2016.

—December 2016

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# Where Will Transportation Drive Global Oil (and Oil Sands) Demand?

**Kevin Birn,** Senior Director
**Tiffany Groode,** Senior Director
**Hossein Safaei,** Associate Director

## About this report

**Purpose.** Since 2009, IHS has provided public research on issues surrounding the development of the Canadian oil sands. However, oil supply is balanced by demand, and the largest source of demand is transport. This report explores future demand for transportation fuels—a critical part of overall global oil demand—and the implications for the Canadian oil sands.

**Context.** This report has been done in collaboration with IHS Automotive Scenarios and is part of the IHS Oil Sands Dialogue. The dialogue convenes stakeholders 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. This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multi-stakeholder input from a focus group meeting held in Toronto, Ontario, on 18 November 2015, as well as participant feedback on a draft version of the report. IHS has full editorial control over this report and is solely responsible for its content (see the end of the report for a list of participants and the IHS team).

**Structure.** This report has five sections.

- Introduction
- Importance of on-road transportation in global oil demand
- Liquid hydrocarbon transportation fuel demand is not likely to peak overnight
- Canadian oil sands are likely to remain a key source of global oil supply
- Concluding remarks

## Part 1: Introduction

Since Edwin Drake drilled the first commercial oil well in 1859, global oil demand has not looked back. Oil—an easily transported, energy-rich commodity—has been found in great abundance and has made its way into nearly every aspect of modern society. In 2016, IHS estimates the world will have consumed about 96 million barrels per day of liquid hydrocarbons, over 1.2 MMb/d more than the year prior and 11 MMb/d more than a decade earlier.

Oil is pervasive. It is used in numerous applications, including medications, cleaning products, computers, mobile phones, and clothing. But, for good reason, it is most commonly associated with transportation fuels—enabling trade and personal mobility, whether by road, rail, air, or water. By far, oil's largest use is for on-road transportation, refined into gasoline and diesel to fuel cars, trucks, and buses. In 2016 on-road transportation accounted for more than half of global oil demand.

Bending the curve of global oil demand growth may be on the horizon. In fact, it has happened before. From 1979 to 1984 global oil demand fell by 6 million barrels per day—a 10% reduction. But since the early 1980s, oil demand has almost always increased each year, underpinned by gasoline and diesel consumption. However, there is increasing uncertainty about the outlook for global oil demand. On one side, new technologies as well as concerns over air pollution, climate change, and urban congestion are contributing to policies that could erode crude oil's dominance in the transportation sector and negatively impact global oil demand. On the other side, the impact of new mobility options, such as car- and ride-sharing already being utilized by millions around the world, is uncertain. Some factors have the potential to be more disruptive, and change could occur faster and in more unpredictable ways than anticipated.

This report will explore the demand for liquid hydrocarbon-based transportation fuels and the relationship with global demand for crude oil. What are the key factors shaping the future of automotive demand for liquid hydrocarbons? How will this influence global crude oil demand? And what does this mean for key sources of global supply, such as the Canadian oil sands? This report has five sections:

- Introduction
- Importance of on-road transportation in global oil demand
- Liquid hydrocarbon transportation fuel demand is not likely to peak overnight
- Canadian oil sands are likely to remain a key source of global oil supply
- Concluding remarks

In the last section of this report we refer to different types of oil sands production methodologies. Additional background information is included in the primer (see the box "Primer on oil sands production.")

## Part 2: Importance of on-road transportation in global oil demand

Around the world petroleum is produced and manufactured into numerous products that find their way into almost every aspect of our lives, from consumer products such as clothing, plastics, detergents, and mobile phones to more commonly thought-of uses such as road asphalt and gasoline (see Figure 1). Petroleum products enable the global economy to function.

Hydrocarbons come in a variety of different forms, differentiated by chemical composition and density. This affects their energy content, handling, and use. The broadest definition is petroleum, which generally encompasses all hydrocarbons historically associated with oil extraction and production. We have provided the general definitions of the subgrouping of petroleum used in this report (see Table 1). This report is focused on transportation fuels that are primarily derived from crude oil and condensate (an ultra-light crude oil). Unless otherwise stated in this report, crude oil includes condensate.

## Primer on oil sands production

The Canadian oil sands

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands is bitumen, an extra-heavy crude oil with high viscosity. Oil sands are unique in that they are extracted via mining and in-situ processes.

**Mining.** About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed and stockpiled for later use in reclamation. The layer of oil sands ore is excavated using massive shovels that scoop the material, which is then transported by truck to a processing facility. About 45% of today's production is from mining.

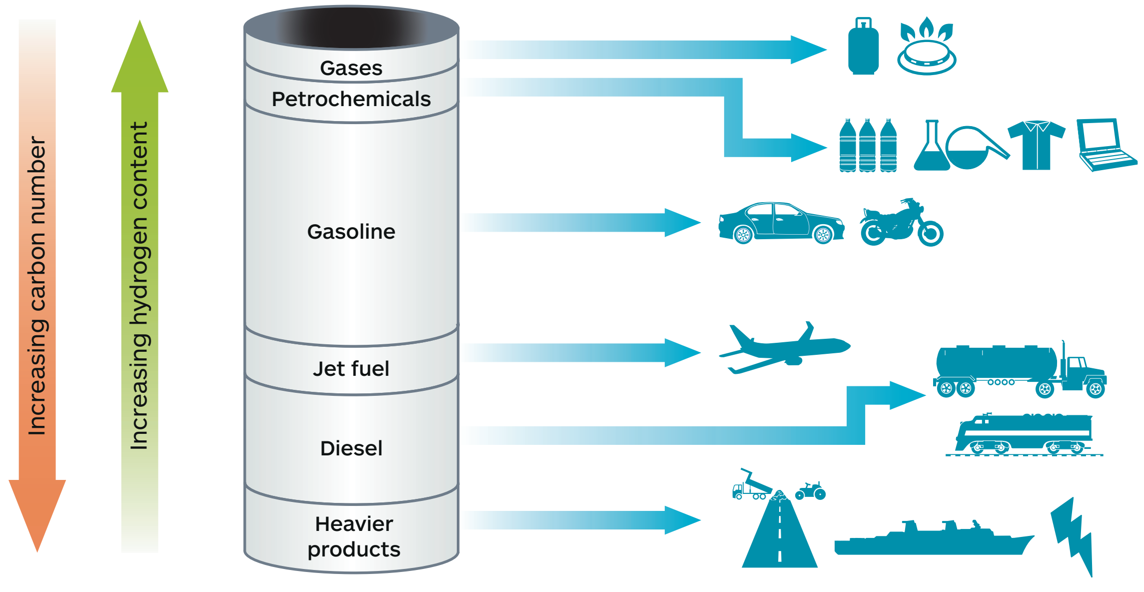
**In-situ thermal processes.** About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. Thermal methods inject steam into the reservoir to warm and lower the viscosity of the bitumen and allow it to flow to the surface. Similar methods are used in oil fields around the world to recover oil. Thermal processes make up 46% of current oil sands production, and two commercial processes are used today:

- **Steam assisted gravity drainage (SAGD) is the fastest-growing method; it is projected to grow from 36% of production in 2016 to 50% of oil sands production by 2030.**
- **Cyclic steam stimulation (CSS), also known as "huff-and-puff," was the first process used to commercially recover oil sands in situ.** CSS currently makes up about 10% of production and is projected to account for less than 7% of total production in 2030.

**Primary production.** The remaining oil sands production is referred to as primary production. Less viscous, it is extracted without steam using conventional oil production methods. Primary production currently makes up nearly 6% and is projected to be less than 5% by 2030.

Figure 1

**Value chain of a barrel of oil**




Source: IHS Energy

Table 1

Petroleum definitions

| State | Category | Description | Primary Use |
|---|---|---|---|
| Liquids | Crude oil | Semi-solid to very mobile at room temperature (API < 50 degrees) | Transportation fuel |
| | Condensate | Ultra-light crude oil (API > 50 degrees) | Transportation fuel |
| | Natural gas liquids | Intermediate range of products between natural gas and crude oil. Some are generally liquid—butane, isobutane, natural gasoline/pentane plus—while others are typically gaseous, such as ethane and propane. | Petrochemical feedstock and transportation fuel |
| Natural gas | | Methane | Heating and power generation |

Note: Although not shown, liquids include biofuels, or hydrocarbons produced from plant matter that are not petroleum as well as gas-to-liquids or methane manufactured into a liquid fuel.

Source: IHS

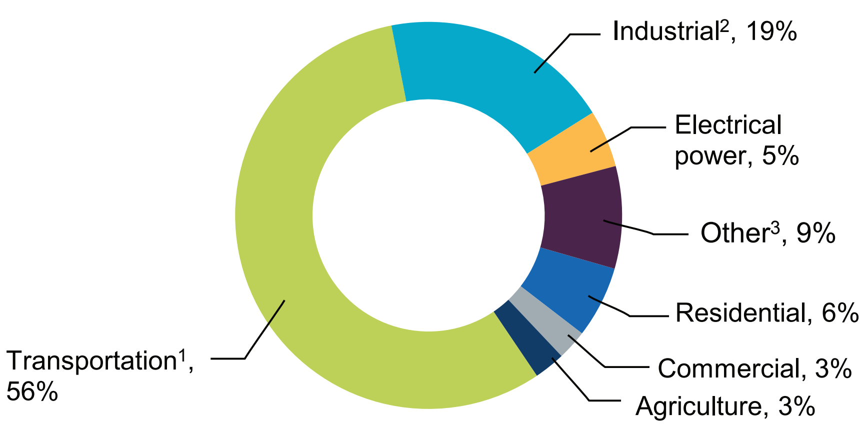


## On-road transportation is the primary driver of crude oil demand

Transportation fuels, such as gasoline, diesel, and jet fuel, are the largest source of global liquid hydrocarbon demand (see Figure 2). Most transportation fuels are derived from crude oil. Although the majority of a barrel of oil typically ends up as transportation fuel, not all of it does and the corresponding demand for crude oil is greater. In 2016 it is estimated the world will consume about 54 MMb/d of liquid transportation fuels (consisting principally of jet, gasoline, diesel, and marine fuel oil). On-road transportation, such as cars and trucks, accounted for nearly four-fifths of this demand, with planes, marine vessels, and trains making up the remainder of oil used in transportation. In 2016, total crude oil demand and total liquids demand were around 79 MMb/d and 96 MMb/d, respectively.

Figure 2

Liquids consumption by sector (total 96 MMb/d in 2016)




Notes: (1) Includes biofuels. (2) Includes feedstocks. (3) Includes energy sector uses, distribution losses, and statistical differences. Negative numbers may indicate use of synthetic fuels.
Source: IHS Energy



## Transportation is a large source of GHG emissions

The combustion of liquid hydrocarbon fuels to power transportation is a major source of greenhouse gas (GHG) emissions. For example, in 2014, the latest year data are available, transportation accounted for more than one-fourth of US GHG emissions—second only to power generation.[1] On-road transportation was responsible for most of these emissions.[2]

Greenhouse gases are emitted over the entire life of transportation fuel: from extraction, to the manufacturing of refined products in refineries, to transportation and distribution to consumers, and, ultimately, to combustion in cars and trucks. The vast majority, 70–80% of emissions over the life of the transportation fuel—from oil production to vehicle tailpipes—occur at the final use: combustion.

1. For more details on US and Canada emissions, see the IHS Special Report *The State of Canada and United States Climate Policy,* August 2016, at www.ihs.com/oilsandsdialogue.

2. See the pdf *Inventory of U.S. greenhouse gas emissions and sinks: 1990-2013,* US Environmental Protection Agency, 2015, accessed 13 September 2016.

# Part 3: Liquid hydrocarbon transportation fuel demand is not likely to peak overnight

Since commercial oil production began, oil demand has generally risen. One notable exception was in the early 1980s, when demand fell 10% as a result of the repercussions of the high prices of the 1970s. This also led to a permanent deceleration in the pace of oil demand growth. But since the early 1980s oil demand has risen almost every year. Indeed, in 2015, lower oil prices contributed to an acceleration of global oil demand growth. Over the longer term, growth may eventually decline as the world transitions away from fossil fuels. But transitions of this scale typically do not occur overnight.

## Global oil demand growth

As we look into the future, changes in transportation, particularly changes in the on-road sector, will be critical to the future of liquid fuel demand. While many acknowledge these changes are occurring, there is a difference of opinion on the possible pace of change. As a result, oil demand forecasts are varied. For example, notable energy forecasters such as the US Energy Information Administration (EIA) and the International Energy Agency (IEA) expect oil demand will continue to grow in their base cases, albeit at a slowing pace out to 2040.[3] In both the IEA and EIA outlooks, global oil demand increases about 20 MMb/d to exceed 120 MMb/d by 2040. However, more bearish outlooks for global oil demand exist. Both the IEA and Statoil conceive of worlds where oil demand peaks before 2040 and 2030, respectively.[4] Our own energy scenarios consider drastically different futures, some where demand continues to grow to 2040 and others where oil demand peaks. These widely different outlooks are a reflection of the uncertainty facing on-road transportation and global oil demand.

IHS divides the global on-road fleet into two broad categories: personal and commercial. They have different characteristics and needs, with large implications for transportation fuel demand and penetration of alternatives such as electric- or natural gas-powered vehicles. For this report we define these two groups as follows:

- **Personal vehicles** or light-duty vehicles (LDV) are the largest market for liquid hydrocarbon fuels, with gasoline being the dominant fuel option. These vehicles are generally owned by individuals and have low utilization rates and a long life (typically between 11 years and 20 years).

- **Commercial vehicles**, also known as medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs), are typically owned by municipalities and businesses. In contrast to LDVs, these vehicles have high utilization rates with a much shorter effective life (three to five years).[5] Diesel serves as the main fuel option for these vehicles, such as trucks and buses.

This section will discuss the factors shaping the fuel demand for these vehicle fleets separately and how they inform the future of global oil demand.

## Personal vehicles: Tomorrow's market is not like the past

There are a number of factors that influence automotive demand for refined products and, in turn, refiners' demand for crude oil. This includes vehicle fuel efficiency, how much people drive, and technology, such as powertrain efficiency (see Figure 3). Looking forward, we are also seeing emerging drivers of change such as car-sharing and ride-hailing. These new mobility options could greatly influence personal miles traveled and fuel demand, but their effects are currently not fully understood. In recent years, there has been intense focus on electric vehicles, but it is more likely the change in an

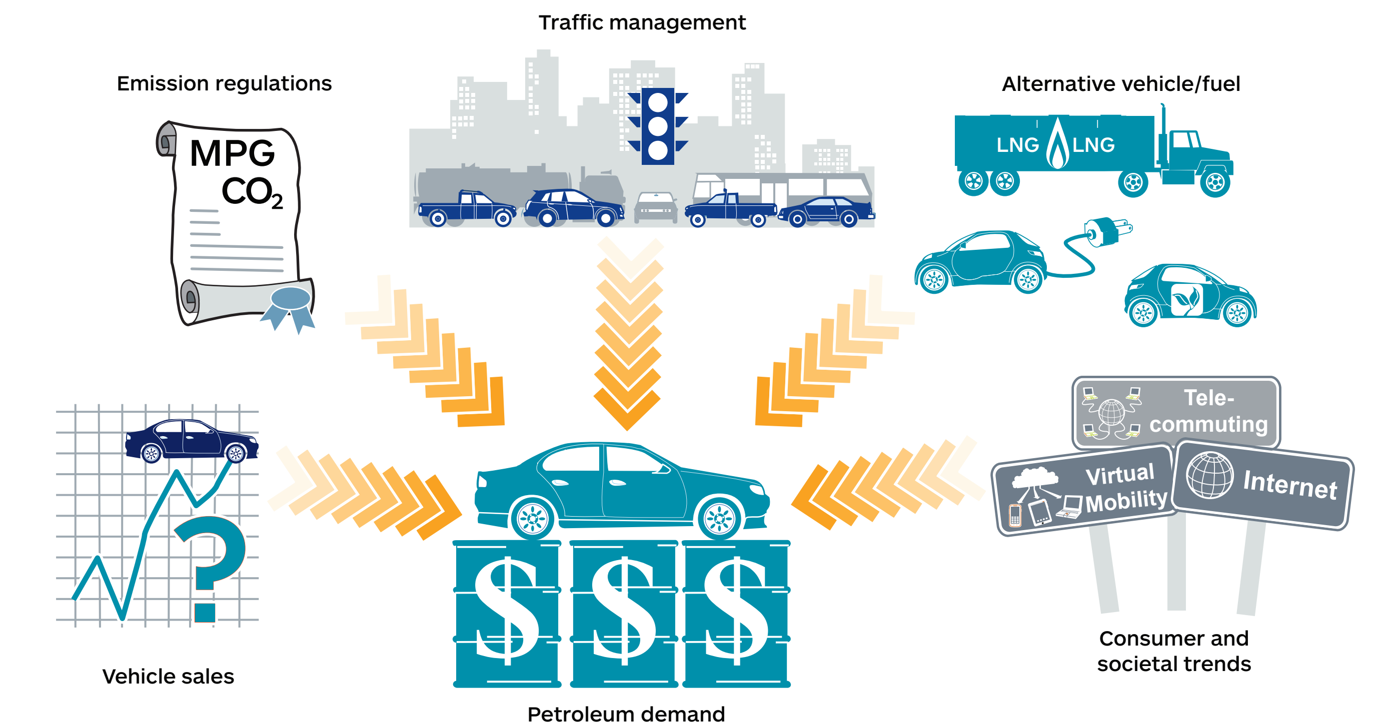
3. See the US EIA report *International Energy Outlook 2016* and the IEA report *World Energy Outlook 2016.*

4. See the Statoil report *Energy Perspectives reports – 2011-2016.*

5. Average vehicle life of a commercial vehicle is more nuanced than light-duty vehicles. The average life of a commercial vehicle depends on the size and application but generally ranges from about 12 years to 21 years. However, the commercial fleet turnover rate is higher. Despite these vehicles staying in the fleet longer than a typical car, their use drastically declines after three to five years for the majority of the fleet. For example, long-haul trucks will go from averaging more than 90,000 miles per year to fewer than 20,000 miles per year.

Figure 3

**Automotive fuel demand drivers that impact future demand**




Source: IHS Energy

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array of variables, from economic activity, to government policy, to shifting consumer preferences, that will collectively influence worldwide oil consumption. This section explores some of these factors.

### Automotive sales to grow, but legacy fleet will delay impact of new technologies

Vehicle ownership and the size of the on-road passenger vehicle fleet (cars and light trucks) influence on-road fuel demand. Although there are a number of potential constraints to vehicle sales, such as vehicle cost, congestion, sales, and end-use restriction policies, IHS expects automotive sales to increase. We believe more—not less—personal mobility will be needed in the future, although it may be lower than earlier estimates may have anticipated.

Historically, forecasting vehicle sales was relatively straightforward: vehicle ownership was strongly correlated with GDP and personal income. In the past, a general rule was that a billion dollars of GDP growth equated to about 1,200 new vehicle sales. Historically, there were also fewer powertrain and fuel options, leaving consumers to choose primarily among different vehicle sizes, styles, and colors. However, additional factors are making forecasting vehicle sales, powertrain, and other personal transportation trends more difficult.

One of the key changes is the effect urbanization is having in developing countries. These cities, being developed upward, have very high levels of population density. This and growing affluence, brought on by economic growth, have led to record vehicle sales. The resulting high density of vehicles in urban areas, coupled with lagging infrastructure, is often leading to crippling congestion in the major cities of the developing world as well as poor air quality.

The severity of these city-level issues is influencing municipal decisions in both the public and private sectors. On the public-sector side, there is an increasing number of policies focused on limiting urban vehicle sales. For example, as of 2016 there are seven cities in China that have some form of city-level vehicle sales restrictions or additional vehicle purchase levy. These policies aim to limit vehicle ownership in response to congestion and air-quality concerns. On the private side, new personal mobility options such as car-sharing and ride-hailing have emerged. Car-sharing and ride-hailing provide people with greater transportation options and convenience while dramatically lowering the cost in comparison to outright ownership. All of these factors affect how consumers view mobility and will impact long-term vehicle sales and use (which we will talk about later in the report).

The effects of advancing policies and shifting consumer preferences on vehicle sales and use are not fully understood. For example, car-sharing could result in higher vehicle turnover and greater sales, which could in turn accelerate penetration of new technologies. Conversely, other changes such as restrictive ownership rules could negatively affect sales and fleet turnover, slowing the effect of new technologies.

On balance, IHS expects that automotive sales will continue to grow, carried upward by developing countries, but at a lower rate than may have been previously anticipated. Automotive sales could expand from about 90 million vehicles in 2016 to nearly 128 million vehicles by 2040. This could lead to an expansion of personal vehicles on roads from 1.2 billion vehicles to 1.8 billion vehicles over the next 25 years. At the same time, changes to vehicle sales and the powertrains sold take time to impact fuel demand. The pace of this change is often attributed to the inertia of the vehicle fleet. IHS estimates average vehicle life globally to be about 15 years (12 years in the United States). This is critical as it means the impact on fuel demand from new vehicle technologies takes time to materially affect the vehicle fleet and overall fuel demand.

Even with a potentially 50% increase in the number of vehicles on the road globally, a number of compounding factors are currently expected to act as a drag on oil demand growth. These include increased vehicle efficiency, people driving less, and the proliferation of alternative powertrains and fuels.

## If people drive less

The amount people drive, measured as total vehicle miles traveled (VMT), is—by far—the most influential factor affecting automotive fuel demand, especially in the short term. For instance, in 2008 during the Great Recession, North American gasoline consumption—a mature market for transportation fuels—declined 3%.[6] Globally, even with continued growth from China, gasoline consumption growth still receded from 1.3% in 2007 to 0.4% in 2008. But was the drop because of weaker vehicle sales, people scrapping their cars, or their cars becoming suddenly more efficient? While vehicle sales did decline 8% between 2007 and 2009 and some people may have gotten rid of their vehicles to cut costs, these were not the primary reasons for the rapid decline in demand. The main reason was that people simply drove less. People who were unemployed stopped driving to work. Households on a budget reduced driving for shopping, entertainment, and holidays. This shift in people's everyday behavior had a quick and pronounced impact on global oil demand, which was 2% lower in 2009 compared with 2007 (5% lower in North America).

Conversely, increases to VMT can cause demand to respond quickly. For example, in response to lower US gasoline prices in 2015 demand increased 2.7%, even though economic growth remained sluggish. Compared with 2014, the average person in 2015 drove almost 4% more, leading to higher gasoline demand.

Although VMT is critical to forecasting vehicle fuel demand, it is also the most difficult to forecast.[7] Factors such as fuel prices, GDP, public transportation, new mobility options, lifestyle, congestion, and availability of parking all influence vehicle use.

IHS believes driving habits around the world are changing. Developed countries, such as the United States, Japan, and in Europe, are characterized as mature automotive markets. A mature market is a place where everyone who wants a car—by and large—has one, and vehicle use is unlikely to change dramatically in the long run.

It was long thought that developing countries would progress along a similar vehicle ownership and use pattern as developed countries. This was expected to drive automotive sales and global oil demand to new heights. However, this seems increasingly unlikely. One of the key differences is the aforementioned effect of urban congestion in developing countries. Crippling congestion, poor air quality, and increasing cost of vehicle ownership in city centers can discourage car ownership and use. In response to these challenges, local- or city-level policies have emerged in cities around the

6. North America includes Canada, Mexico, and the United States.

7. Outside of the United States there are limited data—both historically and forecast—for VMT.

world. Policies such as tolls, congestion charges, city access restrictions, increasing parking costs, and even restrictive sales have proliferated.

In terms of vehicle use, Beijing, China; Sao Paulo, Brazil; and Tehran, Iran, are examples of cities that have vehicle-use restriction policies. These policies limit the use of a personal vehicle in the city center depending on the day of week. Congestion charging, as seen in London, United Kingdom, can also impact the value proposition of driving to work compared with taking public transportation. For example, it now costs about US$15.00 (£11.50) during the day to drive a car into London's city center.[8] These policies make not only owning personal vehicles less attractive (as discussed earlier) but also driving. This could encourage lower sales and utilization rates than may have been earlier anticipated.

The internet and smartphones may also lead to changes in how people consume mobility. It is not just about vehicle ownership or people's relationships with cars. Instead, online businesses enable people to connect over the internet (e.g., teleworking) and shop online. Transportation is also seeing new mobility options such as car-sharing, like Zipcar, and new taxi-style or ride-hailing companies, like Uber and Lyft. For example, in 2014 Uber stated it was transporting 1 million people each day—this is equivalent to moving a city the size of Austin or San Jose in the United States each day.[9] There is also increasing interest about how autonomous vehicles may further alter consumer mobility choices.[10] All of these factors will affect how people consume mobility and influence future automotive use and ownership. A person driving less is generally anticipated to be negative for oil demand. However, a shift in how mobility is consumed is not entirely understood. Autonomous vehicles and ride-hailing could significantly increase oil demand—or push it to lower levels.

### New vehicles are more fuel-efficient

What is well understood is the influence of fuel-economy standards on conventional automobiles. The distance vehicles travel on a gallon of gasoline, often called miles per gallon (MPG), is another important factor affecting transportation fuel demand. The average fuel economy of the automotive fleet is a function of the average efficiency of all the different vehicles and their powertrains on the road. This changes as vehicles enter and exit the market.

Concerns over energy security, air quality, and climate change have led legislators to develop and expand fuel-economy standards to reduce fuel consumption and emissions. Globally, 80% of new passenger vehicle sales are under some type of fuel-economy regulation. These regulations push automakers to advance conventional gasoline and diesel engine technology and to develop advanced powertrains (e.g., conventional hybrids) and alternatively fueled vehicles such as electric- and hydrogen-fueled cars. Although fuel-economy standards lead to improvement in the fuel consumption of new vehicles, the impact on overall vehicle fleet fuel economy tends to be gradual because of the time it takes the fleet to turn over.

### Alternative powertrains: Growing, but it's still early days

Internal combustion engines have been in production for more than 100 years. Today, the combustion engine still makes up nearly 96% of passenger vehicle sales and nearly 98% of on-road vehicles.[11] While alternative powertrains and fuel options—such as electric vehicles, hydrogen fuel cells, and natural gas—continue to try to penetrate this market, they have yet to topple liquid hydrocarbon transportation fuels' hold over personal mobility. But that may be changing.

Helped along by government policy, alterative vehicles, specifically electric vehicles, have started to gain traction in the market. Policies intended to bolster energy security, address climate change, and improve urban air quality are working to increase the adoption of electric vehicles around the world.[12]

8. London's congestion toll varies based on payment method and time of payment. For more information see https://tfl.gov.uk/modes/driving/congestion-charge.

9. See the Uber Newsroom posting "Our Commitment to Safety," accessed 13 December 2016.

10. Autonomous vehicles could transform personal mobility, potentially reducing cost and increasing access, but also shifting consumer preferences and automotive utilization.

11. These values include gasoline, diesel, and flexible-fuel vehicles that can run on alternative fuels to gasoline or diesel. These values would be greater if conventional mild and full hybrid were included.

12. Two notable examples include the *US Department of Transportation Corporate Average Fuel Economy (CAFE) Standards* and the *US EPA tailpipe emission standards.* There are also numerous examples of tax credits and rebates in the United States, parts of the European Union, Canada, Singapore, and others.

This has encouraged large investments in battery technology by both the public and private sectors.[13] Investments are starting to pay off with the cost of vehicle-based lithium batteries declining almost 30% from 2012 to 2015. In 2010, there were only two primary electric vehicles available on the market—the Chevy Volt and the Nissan Leaf—by 2020, IHS expects to see more than 130 models in showrooms.

This does not mean that it is smooth sailing for electric vehicles. A historical challenge associated with the success of electric cars was batteries. Even though there has been a significant reduction in battery cost, electric vehicles made up less than 1% of new vehicle sales in 2016. But there are signs of consumer interest. For example, as of mid-year 2016, 375,000 people paid a US$1,000 deposit to Tesla to buy a car that does not yet exist.[14]

It is unclear how further reductions in battery costs might be applied and how these may impact sales. Car manufacturers have the options of passing along cost savings to the consumer in the form of less-expensive cars, delivering greater range for a similar price point, or even keeping the savings for better margins or redeployment into research and development. Likely some combination of all three will result. Also, consumers' concerns with other issues such as charging time, uncertain resale value, reliability, and safety of electric cars have been hurdles for adoption.

Meanwhile, the internal combustion engine is also not standing still. Combustion technology is constantly improving, making it difficult for alternative technologies to compete. Simultaneously, refueling time and existing refueling infrastructure provide a barrier to new market entrants. While recharging electric cars at home or at a public station still cannot compete with the under-five minutes it takes a conventional vehicle to refill, the cost of charging infrastructure is far less of an obstacle than some other options such as natural gas or hydro. For example, the high cost of compressed natural gas (CNG) and liquefied natural gas (LNG) refueling stations is the primary reason natural gas has struggled to take off as a vehicle fuel. It is estimated that the cost to add an additional gasoline or diesel refueling terminal (pump and tank) to an existing station is less than half the cost to add a similar LNG terminal, which can range more than US$1 million in the United States.[15]

IHS expects sales of electric vehicles to grow but their adoption to be gradual and dependent on favorable policy until at least into the early 2020s, maybe even beyond. In 2016, sales of full electric vehicles (which include pure battery electric vehicles [BEV] and plug-in hybrid electric vehicles [PHEV]) are expected to reach 0.9% globally. While IHS expects both BEV and PHEV sales to increase over time, their influence on the fleet and fuel demand will take time. With the average life of an on-road vehicle globally around 15 years, the impact of new technologies, such as electric vehicles or higher-fuel-economy gasoline vehicles, will take more than a decade to materially affect vehicle fleet and fuel demand. For example, even if one-fourth of all new vehicle sales in the United States in 2016 were electric and maintained that level going forward, by 2030 electric vehicles would make up just 17% of the on-road vehicle fleet. Alone, the impact of increased electric vehicle sales on global gasoline demand will likely be relatively minimal.

## Commercial fleets: Few alternatives to diesel power

Commercial vehicles are used primarily for business applications. As a market, commercial vehicles account for 30% of on-road transportation fuel demand.[16] The majority of commercial vehicle sales and fuel demand are associated with on-road freight transportation by long-haul tractor-trailers.

While gasoline engines dominate the passenger vehicle market, diesel engines dominate commercial vehicles, specifically long-haul tractor-trailers.[17] In 2016, the commercial fleet accounted for about 3% of on-road gasoline and 70% of on-road diesel demand. Diesel engines provide better fuel economy, more power (higher torque at lower speeds), and

13. See the pdf *Guide to Federal Funding, Financing, and Technical Assistance for Plug-in Electric Vehicles and Charging Stations,* US Department of Energy, 2016.

14. See http://www.teslamodel3fan.com/pre-order, accessed 1 November 2016.

15. IHS estimates the cost for an LNG refueling station—just the infrastructure and not including convenience store or land—could run between US$1.2 million and US$2.4 million depending on a range of factors in the United States. See the IHS Energy Special Report *LNG in Transportation: Challenging oil's grip,* 2015.

16. Not including biofuels.

17. Although diesel is more energy-dense than gasoline—capable of producing more energy for equal volumes of fuel—combustion of diesel also emits more air pollutants than gasoline. European fiscal and regulatory policy has historically focused more on efficiency while North America has focused on air quality, which has contributed to greater gasoline use in North America and greater diesel use in Europe.

greater reliability compared with gasoline engines. These are all important for the economical transportation of cargo over long distances.

### Decisions are business-oriented

Commercial vehicle fleet operators make decisions very differently from the personal vehicle market. While both care about costs, personal vehicle consumers often place more value on less-tangible factors such as aesthetics that include vehicle accessories, design, brand, and lifestyle. When a fleet operator is buying a vehicle, its main focus is the vehicle's performance, reliability, and cost—the economics. Commercial vehicles are characterized by high utilization (and thus high fuel cost and turnover rate), extended use (long-distance travel), high reliability requirements, and often high horsepower.

The demand for commercial vehicles is even more sensitive to economic activity than the demand for personal vehicles. When the economy is doing well, more goods are transported and activity increases. In turn, these result in more vehicle sales, more miles traveled, faster fleet turnover, and greater fuel demand. Commercial operators are also very sensitive to fuel prices. In the United States, up to 20% of a trucker's costs can be related to fuel.[18] So as retail diesel prices increase, the cost of trucking increases, making other modes of transport, such as rail, possibly more competitive.[19] Higher diesel prices can also improve the relative attractiveness of alternative fuels such as natural gas.

### Diesel's primary competitor, natural gas, remains behind

Attractive attributes of diesel engines such as efficiency, reliability, and power challenge the penetration of alternative powertrains and fuels. Today, batteries lack the energy density, range, and life to maintain high utilization rates desired by most commercial actors. More energy-dense forms of natural gas, such as CNG and LNG, are penetrating into return-to-base fleets. These vehicles are used for repetitive tasks on fixed routes—such as garbage trucks, city buses, and delivery vans—which require fewer refueling stations.

Fuel switching from diesel to natural gas is based on the time it takes to pay back the greater upfront capital investment required for natural gas engines and refueling infrastructure from the savings obtained by being able to use lower-cost natural gas as fuel. The main drivers for payback are the average VMT each year, the fuel economy, and the fuel-price differential.

In the short term, higher upfront CNG and LNG vehicle purchase costs and limited refueling infrastructure are the primary barriers to natural gas adoption within commercial fleets, particularly long-haul commercial tractor-trailers or "trucking." Additionally, current narrow diesel to natural gas price differentials, fewer CNG or LNG vehicle product offerings, limited vehicle maintenance and business infrastructure knowledge, and longer refueling times are also expected to hinder—but not cease—the adoption of natural gas into long-haul trucking. IHS expects oil prices to increase gradually, which may lead to a greater diesel-gasoline price differential to natural gas, which should contribute to greater CNG and LNG adoption (depending again on other market and policy conditions).

However, should adoption accelerate, the impact on liquid hydrocarbon demand may appear more rapidly for some segments of the commercial fleet than in the passenger vehicle market. For example, in the United States, long-haul trucking typically operates between 75,000 miles per year and 175,000 miles per year (120,000 kilometers and 280,000 kilometers) for three to five years. This faster turnover makes the impact and potential payback of new technologies and fuel choices appear more quickly on the commercial vehicle side than the passenger vehicle market.

### Efficiency and natural gas are expected to slow diesel demand growth

Over the longer term, IHS expects global economic growth to average about 3% per year in our base case scenario until 2030 and push commercial vehicle energy demand and commercial vehicle diesel demand higher. However, diesel demand will not grow unabated as increased fuel economy and natural gas penetrate into the commercial fleets.

18. See the American Trucking Associations' "Reports, Trends, and Statistics," accessed 29 August 2016.

19. For the case of rail, diesel is the dominant fuel source as well; however, it is a smaller share of the transportation cost. For example, CSX claims to be able to move a ton of freight nearly 500 miles on a gallon of diesel fuel. See https://www.csx.com/index.cfm/about-us/the-csx-advantage/fuel-efficiency.

IHS expects business owners will continue to demand more-efficient vehicles and government policy to expand into commercial fleets through initiatives like the US medium- and heavy-duty vehicle GHG and fuel efficiency standard finalized in 2016.[20] Even through the lower oil-price environment, adoption of natural gas will continue, driven by a belief that oil prices will eventually rebound and that environmental regulation will only get stricter and more costly in the future. In North America, particularly, the less-volatile or more-predictable nature of natural gas prices will also aid in adoption. Commercial fleet owners face few options that can match the power, efficiency, and reliability of the diesel engine, but greater fuel economy and lower and less-volatile natural gas pricing will likely lead to a gradual erosion of diesel demand growth.

### The future of oil demand might be more uncertain than we think

As we look at the on-road transportation landscape we see considerable attention being paid to one or two downside risks such as electric vehicles and fuel efficiency. There are other risks, however, ones that may not be fully understood and others that risk being overlooked, including new sources of demand.

Though IHS currently believes the present trajectory is for decelerating global oil demand growth, upside risks also exist. For example, should our expectation regarding the proliferation of legislation restricting vehicle sales and use fall short or expand slower than expected, should India or Africa grow faster than currently anticipated as a result of the large increase in their working-age populations, or should developing countries see a greater shift from more-efficient motorcycles toward less-efficient automobiles than currently expected, crude oil demand could be pulled higher.

As we look into the future, there are a number of uncertainties that could accelerate or decelerate future oil demand. New transportation options such as car-sharing, ride-hailing, and autonomous cars will change how consumers view and value personal mobility. How these new mobility modes and autonomous vehicles ultimately affect demand is still uncertain—and currently poorly understood. They may increase or decrease local fuel demand depending on the fuel they use, how they are utilized, and the policies in place. Today, this is probably the greatest uncertainty facing both the automotive and energy industries.

While new mobility options and alternative vehicles may influence the vehicle market faster than anticipated, large shifts typically take time. The inertia of the legacy vehicle fleet and the recent record-high global vehicle sales will continue to be among the largest barriers to the erosion of liquid hydrocarbon-based transportation fuels. However, this does preclude a more rapid shift in transportation fuel demand. Changes to how consumers use mobility and policies that affect vehicle use can still have a large and relatively rapid impact on fuel demand. Electric vehicles are still relatively young, and it is still early in an adoption curve that could accelerate. This is among the greatest risks to the future demand for liquid hydrocarbon transportation fuels.

The future can be surprising in ways that are difficult to anticipate. IHS maintains alternative scenarios, each equally credible in their own ways. Although not expressly discussed in the report, a brief discussion on alternative scenarios and how the world may evolve differently in each follows (see the box “IHS scenarios”).

## Part 4: Canadian oil sands are likely to remain a key source of global oil supply

Since oil sands production began in 1967, it has taken an increasing role in helping to meet global oil demand. Since 2005, Canadian oil sands have added more than 1.4 MMb/d of production, topping 2.4 MMb/d in 2016. The long-term development of Canadian oil sands, like other sources of supply, is inextricably linked to global demand for crude oil and in turn for transportation fuels.

If future global demand falls short of expectations—such as if disruptive technologies take hold and the transition away from liquid hydrocarbon fuels is quicker than anticipated—what could this mean for oil sands development?

20. See *EPA and DOT Finalize Greenhouse Gas and Fuel Efficiency Standards for Heavy-Duty Trucks,* accessed 13 December 2016.

## IHS scenarios

When developments occur that surprise us, it is often because our assumptions about the present, not to mention the future, have turned out wrong. No course of action will lead to the gift of perfect clairvoyance about the future. Scenarios force us to question the present in order to understand the different ways the future could unfold.

Rivalry, autonomy, and vertigo are the three scenarios that make up our current generation of global scenarios. Defining characteristics of each scenario are below.

- **Rivalry.** Rivalry sees a period of the most intense competition in history among energy sources for market share amid evolutionary social and technology change. Energy rivalry is driven by four factors: price differentials, environmental concerns, technology improvements, and energy security. Gas loosens oil's grip on transportation demand, and renewables are increasingly competitive with gas, coal, and nuclear in power generation. Global crude oil liquid demand continues its long-term trend of decelerating growth.

- **Autonomy.** A transition to an energy mix away from fossil fuels occurs at a much faster pace than expected. Market, technology, and social forces decentralize the global energy system. Generational change and urbanization pressures alter energy demand dynamics—demand for coal and oil falls. Congestion and air-quality issues push more aggressive transportation policies, leading to greater engine efficiency and penetration of alternate powertrains.

- **Vertigo.** The world economy is like weather on a mountaintop—sunny and pleasant one moment, then engulfed in fog and rocked by hurricane-force winds the next. Economic instability undermines confidence and exacerbates risk aversion. Volatile economic growth creates mismatches between demand and supply. Conservative capital investment spending slows the move to a less-carbon-intensive economy. Transportation emissions-related policies slow in favor of more economic-focused initiatives. Increased risk aversion and less-aggressive transportation policy nearly stall the adoption of alternative powertrains.

Each IHS scenario is equally credible with changes in economics, market dynamics, and consumer choices driving an alternative future.

## A lot of effort is needed just to hold global oil supply flat

Although the global oil market is currently well-supplied, maintaining existing levels of supply over the longer term will take considerable effort. There is an ongoing treadmill of the need to find new sources of oil supply to meet growing demand while at the same time make up for production declines as existing fields are exhausted. We estimate in our base case that between 2016 and 2040 global crude oil demand may increase 8 MMb/d while production from existing fields will fall by about 37 MMb/d. This means that about 45 MMb/d of new supply will be required. This is close to half of what the world consumed last year, about 96 MMb/d.

Even in the event disruptive technologies such as the adoption of electric cars accelerate more than anticipated or global oil demand growth falls short of expectations, considerable upstream investment will still be required just to maintain current levels of global oil consumption.

## A multitude of new sources of supply is needed

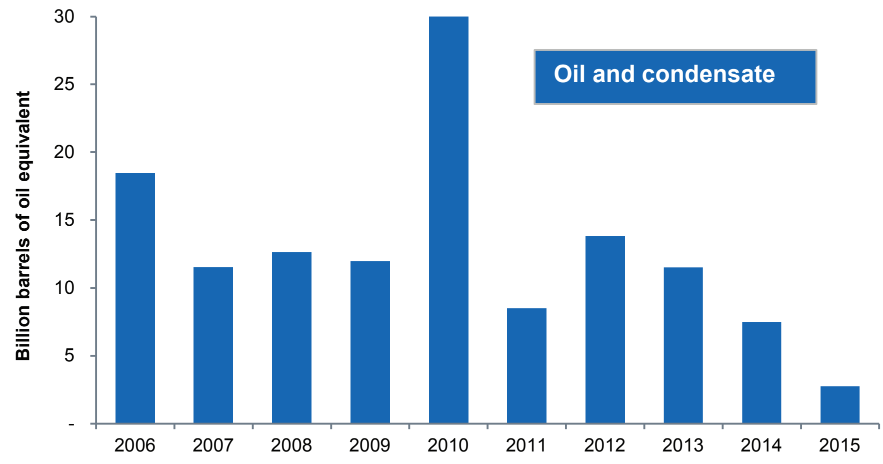
For supply to meet the demand for crude oil in the long term, prices will likely have to rise from 2016 levels to encourage sufficient investment in new oil production.

In recent years discoveries of new conventional oil fields have slowed. Since the deepwater offshore Brazil discoveries in 2010, discoveries of new oil have trended down (see Figure 4). Lower prices have reduced investments in upstream production, including exploration. This has added to pessimism about the prospects of major new discoveries in the immediate future and may place a greater reliance on existing reserves to meet demand.

A multitude of sources of supply from around the world at various costs will be required to meet demand over the longer term. Although late in 2016 OPEC has re-entered the supply management game, its overall output is still greater than it was in 2014 and expected to remain so for some time. OPEC membership constraints have also posed a historical challenge that could result in greater contribution to supply in the future. US tight oil producers have seen costs deflate and are poised to resume supply growth in the future. Although price recovery is anticipated to be gradual, increased output from the Middle East and the United States will not be able to supply all future needs and IHS expects an array of new supply from around the world will be required. This may include production from Russia, Brazil, and the Canadian oil sands.

Figure 4

Conventional discoveries of conventional oil by year (2005 to 2016)




Notes: Data exclude onshore Canada, US lower-48 onshore, and US shallow water.
Source: IHS Energy

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## Competition for capital is fierce and oil sands contribution is not secure

A common perception is that oil sands projects are among the highest-cost sources of oil in the world. However, within any oil-producing region costs vary—sometimes wildly—and the oil sands are no exception. In 2015 IHS published a report detailing oil sands cost structures.[21] Investments in new oil sands mines were found to be among the higher cost globally. However, in-situ projects were lower, breaking even between $50/barrel and $60/barrel WTI. These values overlap the cost structures of two-thirds of the supply additions IHS anticipates to see over the next decade and a half (see Figure 5).[22] Yet this does not make them more competitive.

The factors behind oil sands growth and its role in the world are changing. IHS expects oil sands growth will continue but at a more modest pace than the years preceding the 2014/15 oil-price crash. In a lower-price environment, future investment in oil sands production will focus on the most economic projects—expansions of existing in-situ facilities. Breaking even at the bottom end of the in-situ cost range—currently just beneath $50/barrel WTI—IHS expects that the majority of future activity (2016–30) will come from the expansion of existing facilities. Expansions benefit from being better understood, quicker to first oil, and cheaper to construct.

A lack of production declines in the oil sands will help support growth. Unlike other oil-producing fields globally, oil sands facilities are more akin to manufacturing facilities. Once operating they are built to last 30–40 years with a fixed output. The absence of production declines means that each investment in new oil production results in growth.

Yet, oil sands face additional hurdles that their competitors may not face, such as increasing climate policy in Alberta and Canada or a constrained pipeline system. Both these factors may pose additional costs and uncertainties that their global peers may not face.[23]

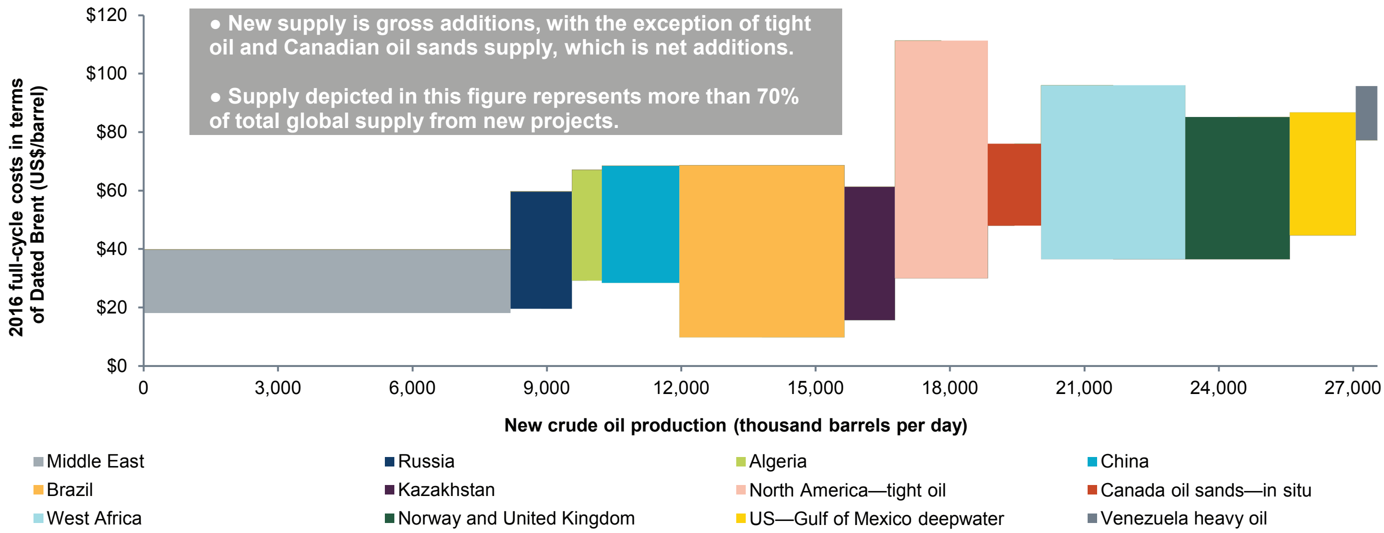
21. For more information on the IHS Oil Sands Dialogue Special Report *Oil Sands Cost and Competitiveness,* December 2015, see www.ihs.com/oilsandsdialogue.

22. A word of caution when reviewing Figure 5. While efforts have been made to capture the most likely representative cost range, costs are not fixed in time and range subject to market conditions and external variables such as exchange rates.

23. For more information on Alberta and Canadian climate policy, see the IHS Oil Sands Dialogue Special Report *The State of Canada and US Climate Policy,* August 2016, www.ihs.com/oilsandsdialogue.

Figure 5

**Indicative cost curve of global crude oil supply from new projects in select areas to 2030**




Notes: This cost of oil is expressed by the Dated Brent price necessary for projects to break even, assuming a 10% internal rate of return. The low- and high-cost projects are chosen from among the more than 600 that IHS has modeled for our cost of oil analysis. For North American tight oil, the cost estimates are for subplays. For each region, the supply additions are gross additions in 2016–30 from new projects, which are calculated by summing the maximum annual production of sanctioned projects, of unsanctioned projects, and of yet-to-find categories for the areas. Exceptions are North American tight oil, the tight oil components of other producing areas, and Canadian oil sands, all of which are net additions from 2015, using the maximum annual value. The global supply shown represents more than 70% of all global supply from new projects, as calculated by the method explained above. Global supply from new projects in all producing areas is not shown, in part so as not to reduce clarity of the figure. The break-even cost estimate for in-situ Canadian oil sands is based on a steam-assisted gravity drainage project. The Middle East includes Saudi Arabia, Kuwait, the United Arab Emirates, Iraq, Iran, Oman, Qatar, and Bahrain. West Africa includes Nigeria and Angola. Break-even costs for groups of countries are weighted by volume.
Source: IHS



In the IHS base case we anticipate that oil sands production will increase, reaching 3.9 MMb/d in 2030. Should this level of growth come to pass, Canada would rank among the top three-to-four sources of global supply growth over this period.

## Part 5: Concluding remarks

The outlook for global oil demand is inextricably linked to transportation fuel demand. Since gasoline won the market battle as the main fuel for cars more than a century ago, crude oil has held a near-monopoly on the transportation fuel market. However, a convergence of disruptive forces could alter demand growth and possibly even lead to its eventual decline. But it is unlikely to occur overnight. A combination of new technology, government policy, new mobility business models, and shifting consumer preferences is set to affect oil's place in transport. The entrenched incumbent fleet, powered by gasoline and diesel, will delay the impact of changes. As a result, global oil demand is expected to continue to increase into the 2030s, although potentially at a decelerated pace.

Although the world is very well-supplied at the moment, a multitude of new sources of supply will be required to meet crude oil demand over the longer term. The Canadian oil sands are positioned to remain one of the key sources of supply growth in the world, but their position is not assured, having to compete for investment and markets with other global sources of oil supply.

## Report participants and reviewers

IHS hosted a focus group meeting in Toronto, Ontario, on 18 November 2015 to provide an opportunity for stakeholders to come together and discuss the future of transportation fuels. A number of participants also 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 is exclusively responsible for the content of this report.

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The Bowman Centre for Technology Commercialization

TransCanada Pipelines LP

University of Calgary

## The IHS team

**Kevin Birn,** Senior Director, IHS Energy, is part of the IHS North American Crude Oil Markets team and leads the IHS Oil Sands Dialogue. His expertise includes energy and climate policy, project economics, transportation logistics, and oil market fundamentals. His recent research includes analysis of the greenhouse gas intensity of oil sands, economic benefits of oil sands development, upgrading economics, oil sands competitiveness, and implications of advancing climate policy. To date, Birn has authored or co-authored 30 reports associated with development of the Canadian oil sands. Prior to joining IHS, Birn worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report Prudent Development of Natural Gas & Oil Resources for the US secretary of energy. Birn holds undergraduate and graduate degrees in business and economics from the University of Alberta.

**Tiffany Groode**, Senior Director, IHS Energy, leads the IHS Automotive Scenarios, including the vehicle and fuels modeling and long-term forecasting. She focuses on the forecasting and impact of future alternative vehicle and fuels technology on the automotive and energy sectors. Groode collaborates between IHS Automotive and Energy experts to integrate, analyze, and forecast how light-duty vehicle sales, powertrain technology, policy, and consumer choice will evolve and impact fuel demand globally over the next 25 years. This includes working with IHS natural gas analysts to develop our LNG forecast in medium- and heavy-duty trucking. Groode also leads research on the well-to-wheels $CO_2$ impact of vehicle fuel emissions. Groode has a PhD and MS in Mechanical Engineering from Massachusetts Institute of Technology and a BS from UCLA.

**Hossein Safaei,** Associate Director, IHS Energy, is a part of the North American Crude Oil Markets team and the Oil Sands Dialogue team. Hossein joined IHS in January 2015 upon completion of his PhD on the techno-economics and public policy of renewable power and energy storage in the United States. He was also a graduate fellow with the Harvard University Center for the Environment. Safaei is a recipient of the Alexander Graham Bell PhD scholarship from the Natural Sciences and Engineering Research Council of Canada, the Future Leaders Award from Natural Resources Canada, and the Graduate Citizenship Award from the Government of Alberta. Safaei holds a Bachelor of Science degree from Sharif University of Technology, a Master of Science degree from the University of Alberta, and a PhD from Harvard University, all in mechanical engineering.

IHS **Energy**

**Special Report**

# Appendix to IHS Special Report: Comparing GHG Intensity of Oil Sands to the Average US Crude

May 2014

**ihs.com**

## About this report

**Purpose.** Oil sands crudes are often singled out for having higher greenhouse gas (GHG) emissions than the average crude consumed in the United States. Often 2005 is used as a reference year baseline. However, since 2005, the mix of crude oil refined in the United States has changed because of the surge in domestic US production and continued growth in the Canadian oil sands. How has this changed the GHG intensity of the average crude oil consumed in the United States? How do the Canadian oil sands compare?

**Context.** This report is part of a series of reports from the IHS Canadian Oil Sands Energy Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Participants include representatives from governments, regulators, oil and gas industry, academics, pipeline operators, refiners, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS conducted our own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Washington, DC, on 22 October 2013 and participant feedback on a draft version of the report. IHS has full editorial control over this report and is solely responsible for the report's content (see the end of the report for a list of participants and the IHS team).

**Structure.** This appendix is a supplementary document to the IHS Special Report *Comparing GHG Intensity of the Oil Sands and the Average US Crude.* The report estimates the average greenhouse gas (GHG) emissions from crude oil refined in the United States in 2005 and 2012 and compares the emissions to those from Canadian oil sands.

We welcome your feedback regarding this IHS Energy report or any aspect of IHS Energy's research, services, studies, and events. Please contact us at customercare@ihs.com, +1 800 IHS CARE (from North American locations), or +44 (0)1344 328 300 (from outside North America).

For clients with access to the IHS Energy website, the following features related to this report may be available online: downloadable data (Excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

# Appendix to IHS Special Report

### Comparing GHG Intensity of Oil Sands to the Average US Crude

## Calculating the life-cycle GHG emission estimates for crude oil

To calculate the GHG emissions intensity of the average crude oil consumed (refined) in the United States in 2005 and 2012, we relied on crude oil GHG emissions estimates that were first published in the IHS Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update*, November 2012 (IHS (2012)). The IHS (2012) report and its associated appendix are available for download here: www.ihs.com\oilsandsdialogue.

In addition to our prior GHG emissions estimates, we required additional GHG intensity estimates to support the estimation of the emissions for the average crude oil consumed in the United States. This appendix details the method used to estimate the GHG emissions for these additional crude oils, including how data were extracted and converted from original studies, as well as other assumptions associated with generating the new estimates. This appendix also summarizes our assumptions on the amount of each type of crude oil consumed in the United States in 2005 and 2012, including detailed information on oil sands.

This appendix has five parts:

- Part 1—Life-cycle GHG emissions estimates derived from the original estimates of California Air Resources Board (CARB)
- Part 2—IHS GHG emissions estimates for Bakken and Eagle Ford tight oil production
- Part 3—GHG emissions estimates for other crude oils
- Part 4—Summary of crude consumed in the United States in 2005 and 2012
- Part 5—Estimating the average oil sands produced and refined in the United States in 2012

Throughout this appendix we refer to a wide boundary for measuring GHG emissions from crude oil. The wide-boundary results include emissions that occur at the production facilities and the refinery (often referred to as the tight boundary), plus GHG emissions that result from consuming upstream fuels during crude oil production and refining (such as emissions from producing and processing natural gas used for production or emissions from off-site electricity production). We do not include emissions from land use in our results since they are difficult to measure, studies are limited, and methods are evolving.[1]

1. For more detailed information on land use emissions, IHS (2012), page 12. Download from www.ihs.com\oilsandsdialogue.

## Part 1—Life-cycle GHG emissions derived from the original estimates of CARB

### *Production emissions*

In support of California's Low Carbon Fuel Standard, CARB estimated the GHG emissions for producing crude oils using the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) v1.0 model. The original CARB GHG emissions estimates were published in Table 8 of the final regulation order.[2]

IHS used CARB estimates to characterize the GHG emissions for the following 15 crude oils:

- Cameroon Lokele
- Venezuela Boscan
- Angola Girassol
- Russian Espo
- Ecuador Napo
- Angola Dalia
- Australia Pyrenees
- Colombia Castilla
- Brazil Marlim
- Angola Plutonio
- US: Alaska North Slope
- Kuwait Ratawi
- Canadian Mixed Sweet
- Colombia Vasconia
- Trinidad Calypso

For each crude oil, the CARB GHG emissions estimates included more than just production emissions. They included emissions from upstream fuels (the emissions that occur outside of the crude oil production facilities such as emissions from producing natural gas or generating off-site electricity), the emissions for transporting the crude oil to a refinery in California, and land use impacts. To isolate the GHG emissions for the production step only, IHS ran the OPGEE model with the CARB inputs.[3] The OPGEE model results were subsequently used to separate the CARB estimate into four groups: upstream fuels, land use, crude transport, and crude production. See Table A1-1 for original CARB data and IHS generated breakouts and conversions. IHS used the production emissions values that were generated from the CARB data and OPGEE model in our baseline calculation.

### Other life-cycle emissions

To estimate the GHG emissions associated with the other life-cycle stages of crude oil consumption (including crude transport, refining, refined product transportation, refined product distribution, combustion, and upstream fuels), we used a method consistent with our previous meta-analysis study (IHS (2012)). The following is a brief summary of the method for estimating other life-cycle emissions from our original work:[4]

2. See source http://www.arb.ca.gov/fuels/lcfs/CleanFinalRegOrder112612.pdf—accessed 6 January 2013

3. Inputs were retrieved from the 12 July 2012 meeting notes found at http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm retrieved February 2014

4. Note: the IHS (2012) study included a detailed appendix that provides a more detailed explanation. This is available for download from www.ihs.com\oilsandsdialogue.

 

TABLE A1-1

## CARB-OPGEE 2012 data, GHG emissions breakouts, and conversions

| | CARB total carbon Intensity (production, upstream fuels, crude transport, and land use) ($gCO_2e$ per MJ) | OPGEE lower heating value (MJ per bbl of crude) ($gCO_2e$ per MJ) | OPGEE crude transport carbon intensity (to California) ($gCO_2e$ per MJ) | OPGEE crude upstream fuels[4] ($kgCO_2e$ per barrel) | OPGEE land use carbon intensity[3] (IHS Energy converted—$kgCO_2e$ per barrel) | Crude transport carbon intensity (IHS Energy converted—$kgCO_2e$per barrel) | Total carbon intensity (crude production, upstream fuels, crude transport, and land use) (IHS Energy converted—$kgCO_2e$ per barrel) | Crude production carbon intensity IHS Energy converted—$kgCO_2e$ per barrel) |
|---|---|---|---|---|---|---|---|---|
| Light crudes greater than 32 API | | | | | | | | |
| Angola-Greater Plutonio | 8.8 | 5,740 | 1.68 | 0.1 | 0.2 | 9.6 | 50.6 | 41 |
| Russia-ESPO | 12.1 | 5,714 | 1.90 | 0.9 | 2.7 | 10.9 | 69.1 | 55 |
| Canadian Mixed Sweet Blend | 7.8 | 5,582 | 0.55 | 1.4 | 2.6 | 3.1 | 43.3 | 36 |
| Medium crudes (26 to 32 degrees API) | | | | | | | | |
| Angola-Girassol | 10.4 | 5,844 | 1.69 | 0.1 | 0.2 | 9.9 | 61.0 | 51 |
| Colombia-Vasconia | 6.6 | 5,901 | 0.77 | 0.8 | 4.7 | 4.5 | 39.1 | 30 |
| Trinidad and Tobago-Calypso | 7.0 | 5,818 | 0.79 | 0.3 | 0.2 | 4.6 | 40.4 | 36 |
| Heavy crudes (20 to 26 degrees API) | | | | | | | | |
| Angola-Dalia | 7.9 | 6,010 | 1.70 | 0.1 | 0.2 | 10.2 | 47.2 | 37 |
| Brazil-Marlim | 6.8 | 6,093 | 1.42 | 0.2 | 0.2 | 8.6 | 41.1 | 32 |
| Cameroon-Lokele | 24.0 | 6,093 | 1.64 | 0.1 | 0.2 | 10.0 | 146.4 | 136 |
| Alaska North Slope[1] | 14.7 | 5,953 | 0.63 | 0.1 | 0.8 | 3.7 | 87.3 | 83 |
| Kuwait-Ratawi | 5.8 | 5,984 | 1.46 | 0.5 | 0.8 | 8.7 | 34.5 | 25 |
| Extra heavy crudes (less than 20 degrees API) | | | | | | | | |
| Australia-Pyrenees | 6.0 | 6,123 | 1.08 | 0.1 | 0.2 | 6.6 | 36.5 | 30 |
| Colombia-Castilla Blend | 6.5 | 6,294 | 1.02 | 0.8 | 5.0 | 6.4 | 40.6 | 29 |
| Ecuador-Napo | 7.5 | 6,123 | 0.52 | 0.8 | 4.8 | 3.2 | 45.6 | 38 |
| Venezuela-Boscan (includes production upstream fuels emissions)[2] | 12.5 | 6,381 | 0.76 | 6.3 | 2.9 | 4.8 | 80.0 | 72 |

Notes:
MJ = megajoule.
1. OPGEE input data provided by CARB did not exactly reproduce the value in Table 8 of the final ruling (12.8 $gCO_2e$ per MJ crude); consequently we used a slightly higher value for this crude than the CARB regulation.
2. This crude had high indirect emissions because natural gas is used to drive the production pumps and the crude is viscous. Since the indirect emissions are material in this case, we included the estimate from CARB in the production emissions.
3. For conventional oil cases, the carbon intensities for land use was calculated from OPGEE output, taking the land use daily GHG emissions and dividing it by the daily oil production in the model.
4. Data extracted from the OPGEE model—GHG emissions Indirect emissions summary. The daily GHG emissions are divided by daily production in the model.

Source: CARB-OPGEE 2012

- **Crude transportation.** Transportation GHG emissions values were assigned according to production location categorized into four geographic regions: Canada, US domestic, Latin America, and overseas.[5]
- **Refining.** Crude density is used to predict the GHG emissions from refining.[6]
- **Refined product distribution.** For all cases, we used 2.3 kilograms (kg) $CO_2$ per barrel.[7]
- **Refined product combustion.** For our analysis we assume average yields from a high-conversion refinery that produces one barrel of refined products (a mix of natural gas liquids, gasoline, and diesel) per barrel of crude oil. For all crudes, the value is 385 kg$CO_2$ per barrel of refined products.[8]
- **Upstream fuels.** Emissions contributions for upstream fuels were broken into two groupings: crude production and crude refining. For all conventional crude oils, upstream emissions were assumed to be zero. For refining emissions, the upstream fuel requirement was estimated based on the crude grade: light, medium, heavy, or extra heavy.[9]

Table A1-2 shows the full life-cycle emissions for the crudes covered in Part 1 of this appendix that were used within the IHS baseline calculation.

## Part 2—IHS GHG emissions estimates for Bakken and Eagle Ford tight oil production

### Production emissions

Using the OPGEE v1.0A model (released June 2012), estimates of the GHG emissions associated with production of US tight oil from the Bakken and the Eagle Ford plays were calculated. The following section outlines the model inputs for estimating the GHG emissions from these crudes.

The OPGEE model is segmented into a number of components. In line with the IHS meta-analysis method, we focused on the following sections for estimating crude production emissions intensity: drilling and development, production and extraction, and surface processing. Model inputs were based on a combination of actual and default/estimated data as well as expert opinions and anecdotal evidence as outlined below. All input information discussed below is summarized in Table A2-1.

- **Development and production data.** Monthly oil, gas, and water production volumes for both plays were sourced from the IHS proprietary oil and gas database that contains actual well and production data from government regulators. Production data for calendar year 2012 were used to calculate play-level average daily production rates and ratios. Additionally, actual completion data for more than 1,600 Bakken and 2,600 Eagle Ford wells drilled in 2012 were compiled and a statistical analysis completed to determine the length of the horizontal leg and the true vertical depth (TVD) of the average well in each play. IHS estimated the initial reservoir pressure for Bakken and Eagle Ford wells based on prior analysis

5. For more information see IHS (2012), Appendix 1, page 12 and Table A1-10.
6. For more information see IHS (2012), Appendix 1, page 12 and Table A1-11.
7. For more information see IHS (2012), Appendix 1, page 12.
8. For more detailed information see IHS (2012), Appendix 1, page 4 and Table A1-2.
9. For more detailed information see IHS (2012), Appendix 1, page 11 and Table A1-8.

 

TABLE A1-2

**Life-cycle emissions for crudes using CARB-OPGEE 2012 data**
**Well-to-wheels GHG emissions for oil sands and conventional crude oils—Tight and wide boundary**
($kgCO_2e$ per barrel of refined product)

| | Tight boundary | | | | | | | | Wide boundary | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Crude name | Crude density (API) | Crude production (includes venting and flaring) | Upgrading | Crude transport | Crude refining | Refined product transport | Refined product combustion | Well-to-wheels (tight boundary) | Crude production: Upstream fuel | Upgrading: Upstream fuel | Crude refining: Upstream fuel | Well-to-wheels (wide boundary) |
| Cameroon Lokele | 21 | 136 | 0 | 9 | 53 | 2.3 | 385 | 586 | 0 | 0 | 13.5 | 599 |
| Venezuela Boscan | 13 | 66 | 0 | 4 | 62 | 2.3 | 385 | 520 | 6 | 0 | 17.5 | 543 |
| US: Alaska North Slope (ANS CARB) | 32 | 83 | 0 | 4 | 41 | 2.3 | 385 | 516 | 0 | 0 | 13.5 | 530 |
| Russian Espo | 34 | 55 | 0 | 9 | 40 | 2.3 | 385 | 490 | 0 | 0 | 13.5 | 504 |
| Ecuador Napo | 19 | 38 | 0 | 4 | 55 | 2.3 | 385 | 484 | 0 | 0 | 13.5 | 498 |
| Angola Dalia | 23 | 37 | 0 | 9 | 51 | 2.3 | 385 | 484 | 0 | 0 | 13.5 | 497 |
| Australia Pyrenees | 20 | 30 | 0 | 9 | 54 | 2.3 | 385 | 480 | 0 | 0 | 13.5 | 493 |
| Colombia Castilla | 19 | 29 | 0 | 4 | 55 | 2.3 | 385 | 475 | 0 | 0 | 17.5 | 493 |
| Brazil Marlim | 21 | 32 | 0 | 4 | 54 | 2.3 | 385 | 477 | 0 | 0 | 13.5 | 491 |
| Angola Plutonio | 34 | 41 | 0 | 9 | 39 | 2.3 | 385 | 476 | 0 | 0 | 13.5 | 490 |
| Kuwait Ratawi | 24 | 25 | 0 | 9 | 50 | 2.3 | 385 | 472 | 0 | 0 | 13.5 | 485 |
| Canadian Mixed Sweet | 36 | 36 | 0 | 10 | 37 | 2.3 | 385 | 470 | 0 | 0 | 13.5 | 484 |
| Colombia Vasconia | 25 | 30 | 0 | 4 | 48 | 2.3 | 385 | 469 | 0 | 0 | 13.5 | 483 |
| Trinidad Calypso | 38 | 36 | 0 | 4 | 35 | 2.3 | 385 | 462 | 0 | 0 | 13.5 | 476 |

Notes: 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.

Source: CARB-OPGEE 2012 and IHS Energy meta-analysis and insights from IHS Energy Eagle Ford Community of Best Practice.[10] This input information is summarized in Table A2-1.

TABLE A2-1

**Bakken and Eagle Ford development and production data**

| GHG intensity analysis—E&P input variables | | | Bakken | Eagle Ford |
|---|---|---|---|---|
| 2012 Producing characteristics | Average oil production | Mbd | 580 | 525 |
| | Average gas-to-oil ratio (GOR) | scf/bbl | 1,020 | 4,500 |
| | Flared gas as percent of total gas production | | 35% | 0.32% |
| | Flared GOR | scf/bbl | 356 | 14 |
| | Average water-to-oil ratio (WOR) | | 0.6 | 0.6 |
| | EUR (20 year) | mbo/well | 252 | 285 |
| 2012 Average well information | New well drills/ Completions | # | 1,604 | 2,616 |
| | True vertical depth (TVD) | ft | 10,000 | 11,000 |
| | Horizontal well lateral length | ft | 8,961 | 5,679 |
| | Initial reservoir pressure | psi | 6,800 | 6,750 |

Note: mbo = million barrels of oil.
Sources: IHS, North Dakota Industria Commission (NDIC), Texas Railroad Commission (TRRC)

- **Recoverable oil reserves.** The expected ultimate recovery (EUR) of oil from a typical Bakken and Eagle Ford well is based on IHS type curve analysis using a 20-year reserve cutoff. From our analysis, we estimate oil recovery in the range of 27% to 29% of EUR during the first year of production. This increases to approximately 55% after year three. The EUR is an important variable as emissions from the drilling and completions phase are divided by the total volume of hydrocarbon produced. EUR estimates for Bakken and Eagle Ford wells are summarized in Table A2-1.

- **Flaring of associated gas.** Gas flaring occurs when the development of infrastructure needed to gather, process, and transport gas does not keep pace with well drilling and subsequent liquids production activity. This is a particularly significant issue in Bakken crude production as gas gathering line networks have not kept up with drilling activity in North Dakota.[11] Flaring of the gas produced in conjunction with oil—referred to as associated gas—increases the GHG emissions of a crude oil. IHS used the flared gas volumes reported by the North Dakota Industrial Commission (NDIC) to estimate the average flared gas volume as a percent of total 2012 gas production. In contrast, flaring of associated gas in the Eagle Ford is a fraction of that for the Bakken. IHS used a flaring estimate from a May 2012 Texas Railroad Commission report in our calculations. For both plays, IHS calculated an average flared gas rate based on the average flared gas-to-oil ratio (GOR). This was entered into the venting, flaring, and fugitive (VFF) emissions section of the OPGEE model to calculate the flaring-related emissions. Flared gas assumptions are shown in Table A2-1.

- **Production/operations conditions.** In characterizing the typical operating environment of the Bakken and Eagle Ford, IHS leveraged internal expertise and anecdotal evidence. We assumed that tight oil production is by primary recovery, which means that pressure depletion is the primary reservoir drive mechanism, as no other fluids are injected into the producing formation to enhance oil recovery. We also made the somewhat conservative assumption that all oil wells require a downhole mechanical pump for the life of the well. A typical new Bakken/Eagle Ford oil well will flow fluid to the surface without artificial lift for a period of time. This ranges from as little as a couple of months to one year and sometimes longer. Following this period, installation of an artificial lift mechanism, such as gas-lift or

10. For more information on IHS Fekete Community of Best Practice see http://www.fekete.com/community-of-best-practice/Pages/About-Community-of-Best-Practice.aspx—accessed 25 February 2014

11. Although this study focused on 2012, recently announced flaring policy changes from the North Dakota Department of Mineral Resources could result in lower emissions intensity for Bakken crude oil. Source: https://www.dmr.nd.gov/oilgas/presentations/NDIC030314_100.pdf—accessed 21 April 2014.

 

bottom-hole mechanical/electrical pumps, lifts fluids to the surface and optimizes well productivity. Based on insights from the IHS Eagle Ford Community of Best Practice, we assumed that the productivity index of tight oil wells is closer to 0.1 barrels per day per pounds per square inch (bbl/psi-d) than to 1 bbl/psi-d, that the average reservoir pressure declines over time, and that wellhead pressures are in the range of 250 pounds per square inch (psi). In terms of water production and disposal, IHS assumed that any formation water produced with the oil (produced water) is separated at the surface, transported (by pipeline or truck), and reinjected into an appropriate subsurface zone via disposal wells. These disposal wells are presumed to be completed in more shallow, higher permeability, water-saturated formations compared to the oil-producing formations. Therefore, surface pumping (electric drive) requirements are expected to be low to moderate (discharge pressure does not exceed 2,000 psi). Table A2-1 summarizes the key development and production data for a typical well in the Bakken and Eagle Ford regions.

- **Drilling and fracturing.** Though the vertical depth of both plays is more or less comparable, the lateral length of an average Bakken well is almost 60% longer than that of an Eagle Ford well. The total distance drilled (vertical plus horizontal distance) factors into the calculation of drilling and development emissions intensity. As the depth or distance drilled increases, more energy is consumed in the drilling process, which increases the emissions intensity.

  The OPGEE model used in our analysis allows drilling-related emissions to be determined based on either a low- or high-intensity environment; however, it does not specifically account for the energy intensity of completion operations such as fracture stimulation. To compensate for this lack of functionality, we increased the drilling intensities to account for fracturing. Bakken and Eagle Ford new well development is reasonably considered lower-intensity drilling (560 million Btu [MMBtu] per 1,000 feet [ft]). IHS conservatively assumed a high intensity drilling environment (978 MMBtu per 1,000 ft) as a proxy to also account for the energy intensity of fracture stimulation completion operations required to achieve productivity in these tight oil wells. As drilling and completion only occur once in a well lifetime, the emissions generated during this phase are divided by the total recoverable oil volume. Consequently, the overall energy intensity contribution from this stage is relatively small. We did not include any methane emissions during well completion.

  In contrast, flaring and venting of associated gas during production operations is the largest contributor to GHG emissions. As previously mentioned, flaring-related emissions are calculated in the VFF section of the OPGEE model. Emissions associated with incidental gas venting that occurs during surface processing operations were based on the model default inputs and calculations.

In summary, there are three main differences between production in Bakken and Eagle Ford: horizontal well lateral length; producing GOR; and the amount of associated gas flared. All three of these significantly influence the GHG emissions calculations. Applying the aforementioned method and assumptions, IHS estimates using the OPGEE model, with GHG emissions for Bakken crude at 9.1 grams (g) carbon dioxide equivalent per megajoule ($CO_2e$ per MJ) compared to 4.1 g $CO_2e$ per MJ for the Eagle Ford (this includes emissions from production, land use, crude transportation, and upstream fuels). Bakken crude energy intensity is significantly higher primarily on account of greater drilling and flaring/venting related emissions.

## Converting OPGEE results for production emissions only

As in Part 1, we needed to make the OPGEE results consistent with the IHS meta-analysis method (IHS (2012)). Model outputs were separated into four groups: upstream fuels, land use, crude transport, and crude production. See Table A2-2 for original CARB data and IHS generated breakouts and conversions. IHS

TABLE A2-2

**IHS 2014 tight oil estimates, GHG emissions breakouts, and conversions from OPGEE model**

| | OPGEE calculated total carbon intensity (production, upstream fuels, crude transport, and land use) ($gCO_2e$ per MJ) | OPGEE lower heating value (MJ per bbl of crude) ($gCO_2e$ per MJ) | OPGEE crude transport carbon intensity (to California) ($gCO_2e$ per MJ) | OPGEE crude upstream fuels[4] ($kgCO_2e$ per barrel) | OPGEE land use carbon intensity*** (IHS Energy converted—$kgCO_2e$ per barrel) | Crude transport carbon intensity (IHS Energy converted—$kgCO_2e$ per barrel) | Total carbon intensity (crude production, upstream fuels, crude transport, and land use) (IHS Energy converted—$kgCO_2e$ per barrel) | Crude production carbon intensity (IHS Energy converted—$kgCO_2e$ per barrel) |
|---|---|---|---|---|---|---|---|---|
| Bakken tight oil | 9.1 | 5,530 | 0.34 | 2.3 | 2.6 | 2.6 | 50.1 | 43 |
| Eagle Ford tight oil | 4.1 | 5,556 | 0.34 | 2.7 | 0.8 | 1.9 | 22.9 | 18 |

Notes:
3. For conventional oil cases, the carbon intensities for land use was calculated from OPGEE output, taking the land use daily GHG emissions and dividing it by the daily oil production in the model.
4. Data extracted from the OPGEE model—GHG emissions Indirect emissions summary. The daily GHG emissions divided by daily production in the model.

Source: IHS 2014

used the production emissions values within our baseline calculation only; we did not use the upstream fuels, land use, or transport estimates from OPGEE.

### Other life-cycle emissions

To estimate the GHG emissions associated with the other life-cycle stages of crude oil (including crude transport, refining, refined product transportation, refined product distribution, and combustion, and upstream fuels), we used a method consistent with our previous study (IHS (2012)). The total life-cycle emissions used for Bakken and Eagle Ford are shown in Table A2-3.

## Part 3—GHG estimates for other crude oils

To support the baseline calculation, we aggregated some of the IHS (2012) GHG emissions estimates and created a California heavy crude average and oil sands bitumen blend product average.

**United States: Average California Heavy** was estimated by taking the average of the four California heavy crude estimates that were included in our IHS (2012) report (see Table A3-1—Average California Heavy Oil Blend GHG emissions).

**Canadian Bitumen Blend** was estimated assuming an equal mix across the four types of oil sands products that contribute a common bitumen blend called Western Canadian Select. The precise mix of crude oils that constitute this blend are proprietary information, so we assumed an equal mix of mining synthetic crude oil (SCO), steam-assisted gravity drainage (SAGD) bitumen, primary cold heavy oil production with sand (CHOPS), and Canadian Mixed Sweet Blend (sSee Table A3-2—Canadian Bitumen Blend Average GHG emissions).

## Part 4—Summary of crudes consumed in the United States in 2005 and 2012

As described in the main report, to support the baseline calculation, we estimated the volume of each crude type consumed in the United States in 2005 and 2012. The number of individual crude oils imported into the United States was large and exceeded the number of specific crude oil GHG emissions estimates

 

TABLE A2-3

**Life-cycle emissions for crudes using CARB-OPGEE 2012 data**
**Well-to-wheels GHG emissions for oil sands and conventional crude oils—Tight and wide boundary**
**($kgCO_2e$ per barrel of refined product)**

| | | Tight boundary | | | | | | | Wide boundary | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Crude name | Crude density (API) | 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) | Crude production: Upstream fuel | Upgrading: Upstream fuel | Crude refining: Upstream fuel | Well-to-wheels (wide boundary) |
| Bakken Blend | 41 | 43 | 0 | 4 | 31 | 2.3 | 385 | 465 | 0 | 0 | 13.5 | 479 |
| Eagle Ford Tight Oil | 40 | 18 | 0 | 4 | 33 | 2.3 | 385 | 442 | 0 | 0 | 13.5 | 455 |

Notes: 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.

Source: IHS 2014 and IHS Energy meta-analysis available. As a result, we consolidated some crude oil streams based on similarities such as API gravity and production practices.

Table A4-1 outlines the percent of the individual crude streams used in calculating the average crude baseline in 2005 and 2012.

## Part 5—Estimating the average oil sands produced and refined in the United States in 2012

### Average oil sands refined in the United States (2012)

Because of the relatively wide range of GHG emissions from oil sands production, IHS estimated the likely mix of products refined in the United States—a mix of bitumen, dilbit, and SCO—to understand the average emissions associated with oil sands products exported to the United States in 2012.

Bitumen cannot be shipped by pipeline—the oil is too thick to flow in pipelines—so diluent is added to enable the bitumen to flow (and the result is a bitumen blend known as diluted bitumen, or dilbit). Although it cannot be shipped in bitumen form, some bitumen-only barrels are refined in the United States. In 2010, the Southern Lights diluent pipeline started operation. The 180,000 barrels per day (bd) pipeline originates in the Chicago area and terminates in Alberta. This pipeline (along with rail movements) allows "bitumen-only" barrels to be refined in the United States because dilbit can be shipped to the refinery and the diluent part of the barrel can be separated and recycled back to Alberta. Thus the refiner converts only the bitumen part of the barrel into transportation fuels.

The type of diluent shipped in pipelines or by rail is not public information, but the majority of the diluent is believed to be natural condensates (rather than diluent recycled from refiners that process bitumen). For the purpose of this calculation, we assumed that about 30,000 bd of oil sands diluent was sourced from refiners returning diluent (refiners consuming bitumen-only). This is not a precise number, and the actual value could be lower. For the remainder of the dilbit transported to the United States, we assume that the full barrel (both the diluent and bitumen) is refined and converted into transportation fuels.

Table A5-1 shows our best estimate of the mix of oil sands products imported to the United States in 2012. These volumes were the basis for our calculation on the GHG intensity of the average oil sands crude refined in 2012.

### Average oil sands produced (2012)

There is a relatively wide range of GHG emissions from oil sands production, depending on the production method deployed. Therefore, IHS estimated the average oil sands produced in 2012.

Table A5-2 shows our best estimate of oil sands produced in 2012. These volumes were the basis for our calculation on the GHG intensity of the average oil sands produced in 2012.

 

TABLE A3-1

**Average California heavy oil blend GHG emissions**
**Well-to-wheels GHG emissions for California heavy oil blend crude oils**
($kgCO_2$ per bbl of refined product)

| | | | | Tight boundary | | | | | | | Wide boundary | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Simplified crude category | Crude name | Crude type | % Composition | Crude production (development, production, flaring) | Upgrading | Crude transport | Crude refining | Refined product transport | Refined product combustion | Well-to-wheels total emissions (tight) | Crude production—Upstream fuel | Upgrading—Upstream fuel | Crude refining — Upstream fuel | Well-to-wheels total emissions (wide) |
| California heavy oil blend | US–Midway–Sunset | Extra heavy | 25% | 128 | 0 | 4 | 56 | 2.3 | 385 | 575 | 18 | 0 | 17.5 | 610 |
| | US–Cymric | Extra heavy | 25% | 111 | 0 | 4 | 53 | 2.3 | 385 | 556 | 13 | 0 | 13.5 | 582 |
| | US–Kern River | Extra heavy | 25% | 89 | 0 | 4 | 61 | 2.3 | 385 | 541 | 8 | 0 | 17.5 | 567 |
| | US–Belridge South | Extra heavy | 25% | 81 | 0 | 4 | 48 | 2.3 | 385 | 520 | 8 | 0 | 13.5 | 542 |
| | Average Heavy | | 100% | 102 | 0 | 4 | 55 | 2 | 385 | 548 | 12 | 0 | 16 | 575 |

Notes: Assume equal weighting of crude streams

Source: IHS Energy 2012

TABLE A3-2

**Canadian bitumen blend average GHG emissions**
**Well-to-wheels GHG emissions for US import crude oils—Tight and wide boundary results**
($kgCO_2$ per bbl of refined product)

| | | | | | | | | | | Tight boundary | | | | Wide boundary | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Simplified crude category | Crude name | Crude type | % Composition | Crude production (development, production, flaring) | Upgrading | Crude transport | Crude refining | Refined product transport | Refined product combustion | Well-to-wheels total emissions (tight) | Crude production—Upstream fuel | Upgrading—Upstream fuel | Crude refining—Upstream fuel | Well-to-wheels total emissions (wide) | Comments |
| Canadian bitumen blend | Oil sands mining SCO | Light | 25% | 28 | 51 | 8 | 46 | 2 | 385 | 521 | 10 | 3 | 15 | 548 | Values per Getting Numbers Right—2012 Update Table A1-17 |
| | Oil sands SAGD bitumen | Extra heavy | 25% | 65 | 0 | 12 | 62 | 2 | 385 | 526 | 23 | 0 | 19 | 568 | Values per Getting Numbers Right—2012 Update Table A1-17 |
| | Oil sands primary CHOPS | Extra heavy | 25% | 38 | 0 | 10 | 60 | 2 | 385 | 496 | 0 | 0 | 18 | 513 | Values per Getting Numbers Right—2012 Update Table A1-17 |
| | Canadian mixed sweet | Light | 25% | 36 | 0 | 10 | 37 | 2.3 | 385 | 470 | 0 | 0 | 13.5 | 484 | CARB 2010 |
| | Weighted average | Custom blend | 100% | 42 | 13 | 10 | 51 | 2 | 385 | 503 | 8 | 1 | 16 | 528 | Weighted average calculation |

Source: IHS 2012 and 2014, CARB 2010

TABLE A4-1

**Comparison of assumed fraction of individual crudes consumed in IHS 2005 Baseline and 2012 Baseline calculations**

| | Contribution to total volume consumed in United States | | | |
|---|---|---|---|---|
| | 2005 | | 2012 | |
| Crude stream name | Volume consumed (mbd) | Percent of total | Volume consumed (mbd) | Percent of total |
| Other Domestic US[2] | 1,980 | 13% | 1,968 | 13% |
| US: Mars | 1,616 | 10% | 1,697 | 11% |
| Mexico Maya | 1,317 | 8% | 763 | 5% |
| Nigeria Bonny Light | 1,295 | 8% | 460 | 3% |
| Iraq Basrah Light | 996 | 6% | 652 | 4% |
| Arab Medium | 962 | 6% | 581 | 4% |
| US: Alaska North Slope (ANS CARB) | 864 | 5% | 526 | 4% |
| Ecuador Oriente | 762 | 5% | 192 | 1% |
| Venezuela Boscan | 625 | 4% | 587 | 4% |
| Other/Unclassified Imports[1] | 609 | 4% | 435 | 3% |
| US: Average California Heavy | 480 | 3% | 422 | 3% |
| Canadian Bitumen Blend (Primary, CSS, and SAGD) | 870 | 6% | 1,316 | 9% |
| Venezuela Petrozuata | 352 | 2% | 254 | 2% |
| Arab Light | 336 | 2% | 880 | 6% |
| Canadian Mixed Sweet | 310 | 2% | 217 | 1% |
| Angola Plutonio | 295 | 2% | 130 | 1% |
| Canadian Oil Sands SCO (Mining and SAGD) | 266 | 2% | 536 | 4% |
| North Sea Forties | 260 | 2% | 30 | 0% |
| Angola Girassol | 196 | 1% | 44 | 0% |
| Russian Espo | 187 | 1% | 102 | 1% |
| North Sea Ekofisk | 149 | 1% | 111 | 1% |
| US: Bakken Blend | 142 | 1% | 702 | 5% |
| Ecuador Napo | 135 | 1% | 66 | 0% |
| US: Eagle Ford Tight Oil | 120 | 1% | 1,141 | 8% |
| Kuwait Ratawi | 112 | 1% | 102 | 1% |
| Brazil Marlim | 92 | 1% | 129 | 1% |
| Angola Dalia | 90 | 1% | 67 | 0% |
| North Sea Mariner | 89 | 1% | 12 | 0% |
| Colombia Vasconia | 72 | 0% | 149 | 1% |
| Iraq Kirkuk | 68 | 0% | 11 | 0% |
| Trinidad Calypso | 62 | 0% | 26 | 0% |
| Canadian oil sands: Cold Lake Dilbit | 40 | 0% | 205 | 1% |
| Kuwait Eocene | 33 | 0% | 29 | 0% |
| Russian Urals | 27 | 0% | 6 | 0% |
| Colombia Castilla | 8 | 0% | 219 | 1% |
| Cameroon Lokele | - | 0% | 57 | 0% |
| Australia Pyrenees | - | 0% | 6 | 0% |
| **Total** | **15,816** | **100%** | **14,829** | **100%** |

1. Note: In IHS GHG analysis, Other/Unclassified Import crudes were assigned the Average Import Crude GHG value
2. Note: In IHS GHG analysis, Other Domestic US crudes (including conventional West/East Texas) were assigned the US Average Crude (2005 DOE/NETL) GHG value

Source: IHS Energy

TABLE A5-1

| Average oil sands export to the United States (2012) | | |
|---|---|---|
| | 2012 Estimated oil sands exports to the US by type (thousand bd) | Percent of total |
| SCO—mining | 456 | 25% |
| SCO—SAGD | 80 | 4% |
| Bitumen blend—Primary (CHOPS) | 345 | 19% |
| Bitumen blend—CSS Dilbit | 342 | 19% |
| Bitumen blend—SAGD Dilbit | 531 | 29% |
| Bitumen SAGD | 45 | 2% |
| Bitumen CSS | 32 | 2% |
| | 1831 | |

Notes: Since the predominant primary production method is CHOPS, this is assumed for all primary production.
All dilbit is assumed to be 28% diluent, and remainder bitumen
For in situ, the split of exports between production methods was assumed equal to the raw production splits.
The bitumen only value, assumes 30,000 bd of diluent was recycled by US refiners back to Alberta. This is not a precise number.
SCO SAGD assumes production from Nexen long lake (30,00 bd) and from Suncor firebag (50,000)

Source: ERCB, IHS

TABLE A5-2

| Average oil sands produced (2012) | | |
|---|---|---|
| | 2012 oil sands produced by type (thousand bd) | Percent of total |
| SCO—Mining | 782 | 44% |
| SCO—SAGD | 80 | 4% |
| Primary (CHOPS) | 241 | 14% |
| CSS—Bitumen | 267 | 15% |
| SAGD—Bitumen | 411 | 23% |
| | 1781 | |

Notes: SCO SAGD assumes production from Nexen long lake (30,000 bd) and from Suncor Firebag (50,000 bd)
Since the predominant primary production method is CHOPS, this is assumed for all primary production.

Source: ERCB, IHS

 

IHS **Energy**

**Special Report**

# Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil

May 2014 **ihs.com**

## About this report

**Purpose.** Oil sands crudes are often singled out for having higher greenhouse gas (GHG) emissions than the average crude consumed in the United States. Often 2005 is used as a reference year baseline. However, since 2005, the mix of crude oil refined in the United States has changed because of the surge in domestic US production and continued growth in the Canadian oil sands. How has this changed the GHG intensity of the average crude oil consumed in the United States? How do the Canadian oil sands compare?

**Context.** This report is part of a series of reports from the IHS Canadian Oil Sands Energy Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Participants include representatives from governments, regulators, oil and gas industry, academics, pipeline operators, refiners, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS conducted our own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Washington, DC, on 22 October 2013 and participant feedback on a draft version of the report. IHS has full editorial control over this report and is solely responsible for the report's content (see the end of the report for a list of participants and the IHS team).

**Structure.** This report has four parts and an appendix:

- Part 1: Introduction
- Part 2: US average crude oil baseline method and common pitfalls
- Part 3: Results
- Part 4: Conclusion
- Appendix: Detailed method, source data, and calculations (a separate document)

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# Comparing the GHG Intensity of the Oil Sands and the Average US Crude Oil

## Key insights

Oil sands are often singled out for having higher GHG emissions than the average crude oil consumed (refined) in the United States. The most commonly referenced year for such comparisons is 2005. However, the mix of crude oil consumed in the United States has changed dramatically since 2005. Have these changes—especially the increase in imports of Canadian oil sands and the growth in US domestic light, sweet crude oil production—changed the GHG intensity of crude oil consumed in the United States? And how does crude oil from the Canadian oil sands compare to the US average today?

- Despite significant changes in the mix of crude oil supplied to US refineries between 2005 and 2012, the average GHG intensity was unchanged. Growth in supply and consumption of relatively lower-carbon crudes offset increased use of relatively higher-carbon crudes.

- Forty-five percent of the crude oils consumed in the United States are within the same GHG intensity range as those from the Canadian oil sands. Comparing the oil sands against the average crude oil baseline estimated by IHS for 2012, refined products from oil sands has life-cycle GHG emissions that are between 1% and 19% higher than the average crude oil consumed in the United States. This places oil sands within the same GHG intensity range as 45% of crude oil supplied to US refineries in 2012. Two-thirds of the crudes in this range came from Latin America, Africa, the Middle East, and some US domestic production.

- GHG emissions figures for the average crude oil consumed in the United States should be treated as an estimate. The IHS estimate of the GHG emissions for the average crude in 2005 was almost 4% higher than an often-cited estimate from a US Department of Energy study. The difference gives an indication of the margin of error in estimating the GHG emissions for the average US crude oil. There are insufficient data on the life-cycle GHG emissions for many crude oils to obtain a precise value for the average crude oil consumed in the United States.

- The average GHG intensity for crude oil consumed in the United States can be a useful reference point to compare crude oils. However, it can also lead to confusion. For instance, it is misleading to use the baseline as a reference point when estimating the incremental GHG emissions associated with greater US consumption of one type of crude oil. For example, an increase in the import and consumption of oil sands will most likely replace a similar crude oil, not the average crude oil. The most likely substitute for Canadian oil sands in the United States is Venezuelan crude oil, which has a GHG intensity within the same range as the Canadian oil sands.

—May 2014

# Comparing the GHG Intensity of the Oil Sands and the Average US Crude Oil

## Part 1: Introduction

How much GHG is generated from the consumption of various types of crude oil? This question matters because policies are being rolled out based on various assumptions that could have significant economic consequences for different crudes, notwithstanding the validity of those assumptions.

The most direct policy example is Low Carbon Fuel Standards (LCFS), which use the life-cycle GHG emissions of crude oils as a basis for regulating the carbon intensity of transportation fuels. In the European Union and California, LCFS initiatives are in various stages of advancement. The GHG intensity of crude oil is also factoring into other decisions. For example, it has been a main topic in the debate about approving new crude oil pipelines between Canada and the United States. This was most evident in President Barack Obama's 25 June 2013 climate address when he pledged not to approve the Keystone XL pipeline if the project would "significantly exacerbate the problem of carbon pollution."

Thus, it is very important to understand GHG intensity. However, assessing the GHG intensity of any crude oil is a complex exercise. Data availability and quality are a challenge, as are differing methods of calculation. Understanding the average GHG intensity for crude oil consumed in entire country is even more challenging. Despite the uncertainty, individual crude oils are often compared to the average crude oil consumed (or refined) in the United States.[1] The most commonly cited GHG intensity estimate comes from a 2008 study by US Department of Energy's National Energy Technical Laboratory (DOE/NETL). DOE/NETL estimated the life-cycle GHG emissions for the average US crude oil consumed in 2005.[2]

However since 2005 (the year the average GHG intensity was quantified), the source of crude oil supplied to US refineries has changed dramatically. For our study we compared the estimates from 2005 to those of 2012. Major changes between these years include

- **Growth of oil sands and other Canadian heavy imports.** Between 2005 and 2012, US imports of oil sands (diluted bitumen [dilbit] and synthetic crude oil [SCO]) and other Canadian heavy supply increased by 900,000 barrels per day (bd), or 75%—from 1.2 million barrels per day (mbd) to nearly 2.1 mbd. In 2012, about 1.5 mbd was sourced from the oil sands, accounting for about 14% of US imports.[3]

- **The rise of US tight oil.** Nonexistent in 2005, tight oil production, led by production from the Bakken in North Dakota and the Eagle Ford in Texas, reached 1.8 mbd in 2012. Tight oil accounted for almost 30% of US domestic supply in 2012.[4] Tight oil continues to grow, and in 2013 total US tight oil production reached 2.7 mbd.

- **Decline in Mexican imports.** Between 2005 and 2012, US oil imports from Mexico declined almost 600,000 bd, or 38%.

1. Throughout this report, *consumed* and *refined* are used interchangeably.

2. DOE/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.

3. The estimate of volume of US imports of oil sands is based on data from the Canadian National Energy Board (NEB) and the US Energy Information Administration (EIA). We have added 250,000 barrels per day (bd) to the reported values from the NEB to account for some oil sands blends that the agency categorizes as heavy conventional crudes.

4. Total US domestic production of 6.4 mbd; source US Energy Information Administration.

- **Reduction in light, sweet crude imports from Nigeria and other African suppliers.** As a result of growing domestic tight oil supply, imports of light, sweet crude oil from offshore suppliers dropped. From 2005 to 2012, Nigerian imports dropped more than 800,000 bd, or 64%. Other African suppliers declined by a similar percentage. It total, between 2005 and 2012, US imports of all light, sweet crude oil (not just African) fell 64%, from 3.8 mbd to 1.9 mbd.

- **Lower Alaska North Slope crude oil production.** By 2012, production was 40% lower than in 2005—a drop of more than 300,000 bd.

- **Declines in imports of Venezuela heavy crude oil, along with resources from other Latin American suppliers.** In 2012, combined US imports were 400,000 bd lower than in 2005.

Have these changes altered the GHG intensity of the average crude oil consumed in the United States? This report aims to answer that question. But to summarize, the conclusion is "no."

Since 2009, IHS has published a series of public reports quantifying the life-cycle GHG emissions of oil sands compared with other crude oils. Based on this body of prior research and some new research detailed in this report, we have estimated the GHG intensity of the average crude oil refined in the United States in 2005 and 2012. Our most recent GHG study, the IHS Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update*, November 2012 is referred to as IHS (2012) in this report. The original report can be downloaded at www.ihs.com\oilsandsdialogue.

This report comprises five parts, including this introduction and an appendix:

- Part 1: Introduction

- Part 2: US average crude oil baseline method and common pitfalls

- Part 3: Results

- Part 4: Conclusion

- Appendix: Detailed methodology, source data, and calculations (contained in a separate document that can be downloaded at www.ihs.com\oilsandsdialogue)

Throughout this report, we make reference to commonly understood principles of life-cycle analysis for petroleum-based transportation fuels. The "Life-cycle GHG emissions from crude oil: Basic terms" box

### Life-cycle GHG emissions from crude oil: Basic terms

**Life-cycle analysis of GHG emissions from crude oil.** Life-cycle analysis estimates the amount of GHG emissions associated with the entire life of a product. For petroleum fuels, this includes crude oil production, transport, refining, refined product transport, and ultimately combusting the fuel in a vehicle (see Figure 1). The entire life cycle is referred to as "well-to-wheels." Emissions that include everything up to but not including combustion are described as "well-to-tank." When GHG emissions are viewed on a well-to-wheels basis, emissions released during the combustion of fuel (such as gasoline or diesel) make up 70% to 80% of total emissions. *These combustion emissions are the same for all crudes. Whether the fuel is derived from oil sands or conventional oil, the combustion emissions are equal.*

## Life-cycle GHG emissions from crude oil: Basic terms (continued)

**Wide boundary for measuring GHG emissions from crude oil.** Throughout this report, we use a wide boundary for measuring the life-cycle GHG emissions from crude oil. Wide boundary results include emissions that occur at production facilities and refineries (often referred to as the tight boundary) plus GHG emissions that result from fuels used in the production and refining of crude oil (such as emissions from producing and processing natural gas used for production or emissions from off-site electricity production). Emissions from land use were not included in our results, since they are difficult to measure, studies are limited, and estimation methods are evolving.*

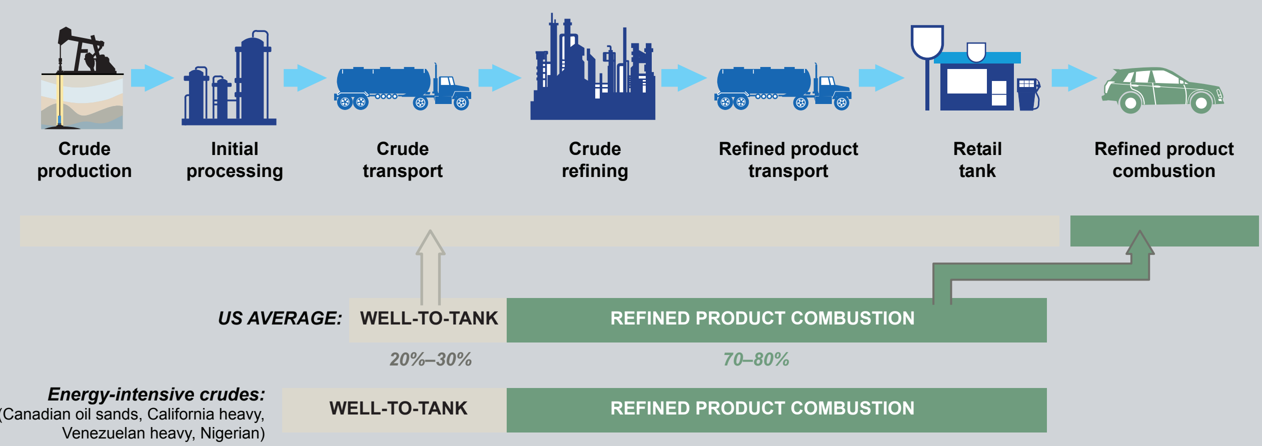
**Areas of uncertainty in measuring GHG emissions from crude oil.** Measuring the life-cycle emissions for crude oil is a complex process, and there can be significant variability in the estimates for a single crude oil. In our previous study, IHS (2012), we found that when multiple studies were compared, estimates of production emissions varied by an average of 30%. Depending on the crude oil, this level of error equates to between 5% and 15% variance in the well-to-wheels life-cycle GHG emissions estimate; in some cases the error is greater than the GHG reductions that LCFS policies require.

There are numerous sources of uncertainty in measuring emissions of crude oil. Three key challenges are

- **Data quality and availability.** This is the most significant factor contributing to the uncertainty in measuring crude oil GHG emissions. Accurate data are often difficult to obtain. Frequently, oil and gas data are considered proprietary. For example, flaring and venting, which can represent a large source of production emissions, must often be estimated from satellite imagery because of a lack of data. However, for Canadian crudes, venting and flaring data are measured, audited, and available.

FIGURE 1

**Lifecycle GHG emissions for petroleum fuels**




40526-1
Source: IHS Energy



*For more information on land use emissions, see the IHS Energy Special Report *Oil Sands Greenhouse Gases, and US Oil Supply: Getting the Numbers Right—2012 Update*, November 2012, page 12. This can be downloaded at www.ihs.com\oilsandsdialogue.

### Life-cycle GHG emissions from crude oil: Basic terms (continued)

- **Allocation of emissions to coproducts.** For crude oil, life-cycle analysis requires attributing emissions to multiple products produced by a refinery, such as the gasoline or diesel. Studies of well-to-wheels emissions vary greatly in how they allocate emissions to refined products. For instance, some studies allocate all GHG emissions to 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. And yet others divide GHG emissions based on the energy content of the products or the energy consumed in making the products. For this reason (among others), it is not valid to directly compare absolute GHG emissions estimates among studies.

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

For more information on areas of uncertainty in measuring GHG emissions from crude oil please refer to the IHS (2012) report.

provides a brief overview of these terms. It also highlights some of the uncertainty in measuring GHG emissions from crude oil.

## Part 2: Average crude oil baseline method and common pitfalls

In estimating the GHG emissions for the average crude oil consumed in the United States, IHS used a different method from the one used in the DOE/NETL study. This section explains our method and compares it to the DOE/NETL approach. We also identify some common pitfalls in using an average crude oil GHG intensity baseline when comparing the GHG emissions from different crude sources.

### DOE/NETL used a top-down approach

A top-down approach weights the average life-cycle emissions at a country level by the volume of crude oil consumed from each country to arrive at an average GHG intensity. DOE/NETL used this approach to estimate the average GHG emissions for crude oil consumed in the United States in 2005. For example, it estimated the life-cycle GHG emissions intensity for the average crude imported from Mexico, Venezuela, and others; these values were weighted by the amount of crude oil imported from each nation to produce an average intensity estimate. Canada was one exception, since it estimated one average value for Canadian conventional sources and another for the Canadian oil sands. The DOE/NETL study concluded that emissions from oil sands were 17% higher than that from the average crude consumed in the United States in 2005. This is higher than the IHS estimate that represents the most current oil sands data and operations. Using a consistent baseline to DOE/NETL (which differs from the baseline used in the rest of this report), we estimate the average oil sands refined in the United States are now 12% higher than the emissions from average crude in 2005 (using the IHS baseline it would be 9%) (see Table 1 at the end of this report). Although the DOE/NETL value is frequently used to characterize the GHG emissions from oil sands, it is dated, relied on limited data sources, and is outside of the range of IHS and other studies.

## DOE/NETL Canadian oil sands assumptions

The DOE/NETL study is dated and no longer represents current oil sands operations—which have lower emissions compared with 2005 (the DOE/NETL GHG emissions for oil sands extraction and upgrading are about 1.5 times higher than the IHS and other study results of current operations). Also, the DOE/NETL estimate does not account for how bitumen products are actually shipped to the US market for refining—as a blend of bitumen and lighter diluents.

**Mining and upgrading SCO**. About half of today's oil sands production is from mining integrated with an upgrader. DOE/NETL 2009 assumes a 2005 mining and upgrading emission value of 134 kilograms of carbon dioxide equivalent ($kgCO_2e$) per barrel of SCO, or about 120 $kgCO_2e$ per barrel of refined products.[5] The source for this value is not clear. The DOE/NETL values are higher than those of any studies used in the IHS (2012) (which looks at the range of results across eight sources for mining and upgrading published since 2010). The range of results for the sources IHS studied was 87.5 to 103 $kgCO_2e$ per barrel of refined products, and the average value was 92 $kgCO_2e$ per barrel of refined products (see IHS (2012) Appendix A1-9 for data).

**Thermal extraction emissions.** Thermal extraction methods inject steam into oil sands in situ (or in-place) through a well to heat up the bitumen and allow it to flow to the surface. Two thermal processes are in wide use in the oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). On average, SAGD has lower GHG emissions per barrel produced than CSS. In 2012, about 65% of the oil produced from oil sands thermal extraction was from the SAGD method, and SAGD production is growing. To estimate GHG emissions for producing diluted bitumen, or dilbit, with thermal extraction, the DOE/NETL study draws on a 2005 value for producing bitumen using the relatively high-emission CSS method (a process used for 35% of current production) and assumes 134 kgCO2e per barrel.[6]

With thermal production, there is no source for the estimate used in the DOE/NETL 2009 paper. However, in a previous paper published in 2008, DOE/NETL does provide a source for this value (a 2006 estimate for CSS from Imperial Oil's Cold Lake operation to produce a barrel of bitumen). In addition, the estimate assumes the production of a barrel of bitumen only, a product that cannot be transported by pipeline. The IHS (2012) analysis (analyzing eight sources published since 2010) found that thermal extraction of dilbit produced between 43 and 109 $kgCO_2e$ per barrel of refined products, and the average value (assuming 65% dilbit from SAGD and the remainder from CCS) was 80 $kgCO_2e$ per barrel of refined products (see IHS (2012) detailed Appendix A1-9 for data).

## IHS used a hybrid bottom-up approach

A bottom-up approach gathers life-cycle GHG emissions intensity data on each individual field or marketable crude (such as Mexican Maya or Nigerian Bonny Light) and weighs them by the volume of each crude consumed to arrive at an average US crude value. We estimate that in 2012, the United States consumed over 150 unique crude types.

The main challenge of using a bottom-up approach is in estimating GHG intensity values for 150 unique crudes. Limited data on international oil production practices make estimating GHG emission, intensities for such a large group of crude oils impractical (see the box "Life-cycle GHG Emissions from crude oil: Basic terms" for more background). Consequently, IHS used a hybrid bottom-up method (see Figure 2).

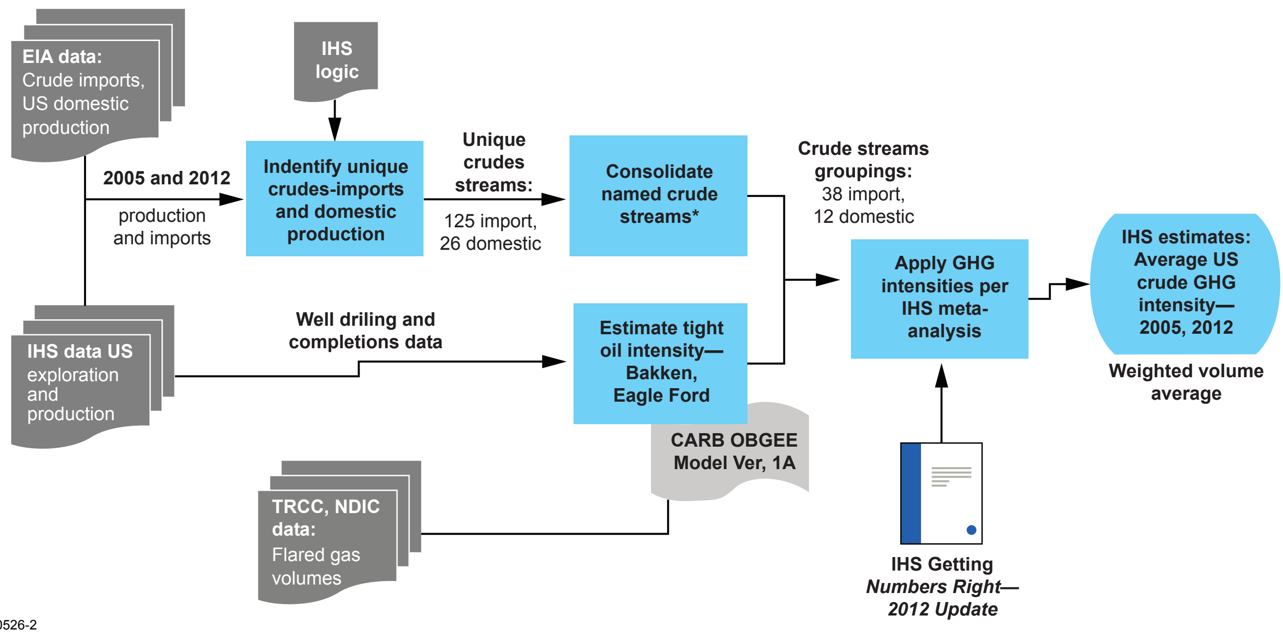
5. SCO is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. These units are called upgraders. SCO resembles light sweet crude oil with API gravity typically greater than 30 degrees.

6. 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.

FIGURE 2

**IHS hybrid bottom-up method for estimating the average GHG emissions for the average US crude oil**




40526-2
*Consolidation considered production practices and crude quality
Source: IHS, US EIA, TRRC, NDIC, CARB



We applied the following steps to calculate the GHG intensity of the average US crude oil:

- **Identify each crude oil consumed.** Based on US government import and production data and using the IHS estimate of the specific crude oil based on country of origin, density, and sulfur information, we estimated the volume of US crude consumed by individual crude streams (e.g., Nigerian Bonny Light or Iraq Kirkuk). This resulted in 151 unique crude oils (125 imports and 26 domestic).

- **Consolidate the named crudes streams.** Estimating precise GHG intensities for 151 crude streams is not practical or even possible. We combined the streams into groupings with similar production practices and qualities. This resulted in 51 consolidated crude oil streams (38 imports and 12 domestic).

- **Estimate the GHG intensities for each crude oil.** In IHS (2012), we published a number of GHG emissions estimates for crude oil. However, our previous report did not include values for all 51 consolidated crude streams. Since then, we generated new life-cycle GHG intensity estimates for US domestic tight oil production (Eagle Ford and Bakken production). We also generated new estimates for 15 other crude oils based on estimates from the California Air Resources Board (CARB). For more information on new GHG emissions estimates and sources, please refer to the Appendix (download at www.ihs.com\oilsandsdialogue.)

- **Calculate the life-cycle GHG emissions for the average US crude oil.** Once GHG intensities were available, we calculated the average GHG intensity by weighting the volume of each crude stream (in 2005 and 2012) by its carbon intensity. Even with our expanded list of crude oil GHG emissions intensities, some of the 51 consolidated crude streams were still unknown (the unknown crudes oils accounted for about 15% of the total volume). As a result, we applied an average GHG intensity to account for the crude oils with missing values.

Comparing the country-level approach used by DOE/NETL, our view is that our hybrid bottom-up method provides more precision. Since we group crude oils based on quality and production practices, our approach is more indicative of GHG intensity than country of origin. However, both methods have inherent uncertainty and deliver estimates rather than precise values.

### Assume static GHG intensity of individual crude oils between 2005 and 2012

In calculating the 2005 and the 2012 baselines, we used the same GHG intensity value for each crude oil. This simplification was required owing to a lack of data, which makes it impractical to quantify the GHG emissions in both 2005 and 2012 for all 51 consolidated crude oil streams. However, the GHG intensity of crude oils can change over the longer term. For example, using emissions data from Environment Canada and historical production data, the average GHG intensity of oil sands production decreased more than 26% between 1990 and 2011.[7] However, in general, over a shorter time period—such as seven years—the change is less pronounced. Consequently, we do not expect the static GHG intensity assumption between 2005 and 2012 to be a major factor in our results.[8]

### Common pitfalls in using the average crude oil baseline

The DOE/NETL 2005 baseline is frequently used in comparisons of crude oil GHG intensities. Common baselines can be useful, since they provide a reference point for comparisons. However, at times the DOE/NETL baseline has been used inappropriately—for instance as a reference point to estimate the incremental GHG emissions associated with greater US imports of crude derived from Canadian oil sands. There are two primary faults with using the average crude baseline in this way:

- **Oil sands will not replace the average crude consumed in the United States.** The vast majority of future oil sands production growth will be heavy crude oil that targets US Gulf Coast refineries that are configured to processing heavy crude oils. Growing volumes of Canadian heavy crude are likely to displace other heavy crude oils imported from Venezuela and Mexico. Based on our earlier analysis reported in IHS Energy Insight *Keystone XL Pipeline: No Material Impact on US GHG Emissions* (download at www.ihs.com\oilsandsdialogue), crude from Venezuela is in the same GHG intensity range as oil sands. Further, if Canadian oil sands supply to the US Gulf Coast is limited, Venezuela is the most likely alternative source of supply.

- **The DOE/NETL baseline estimates the carbon intensity at a fixed point in time, 2005, but since that time the US crude slate has changed considerably.** Often the baseline is used to compare the GHG emissions of particular crude oil today or even long into the future (over more than 20 years or more into the future over the useful life of an infrastructure investment such as a pipeline). However, for this purpose, the baseline should be used with caution, since the future GHG intensity of both the US average crude oil and the crude being compared is uncertain.

## Part 3: Results

This section presents the results and key conclusions from our average US crude oil baseline analysis. The volume and intensity of US crude slate is shown in Figure 3.

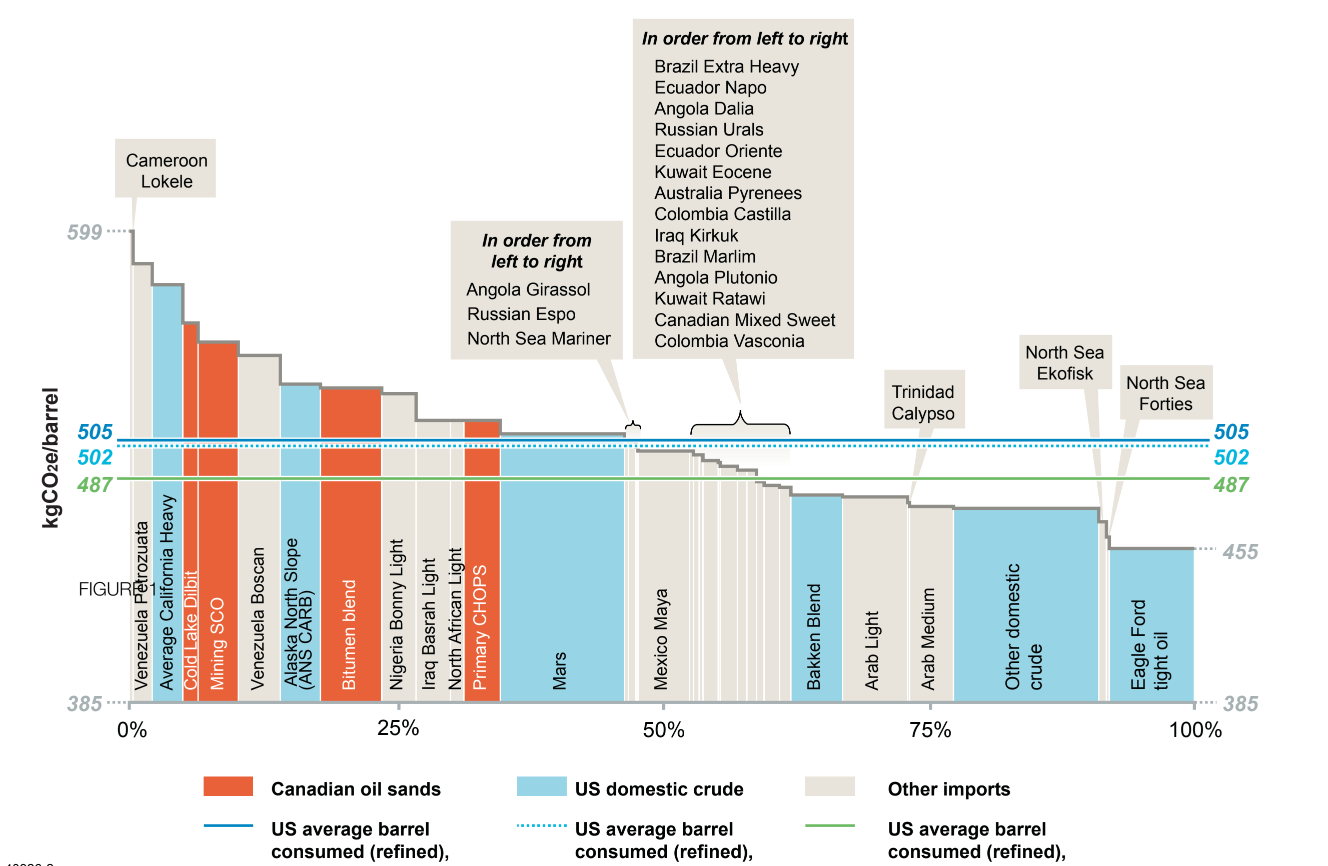
7. Environment Canada, National Inventory Report 1990-2011: Greenhouse Gas Sources and Sinks in Canada http://www.ec.gc.ca/Publications/default.asp?lang=En&xml=A07ADAA2-E349-481A-860F-9E2064F34822–accessed 27 February 2014. For more information on the drivers of GHG emissions reductions and future outlooks, see *IHS Special Report "Oil Sands Technology: Past, Present, and Future"*, January 2011 (download at www.ihs.com\oilsandsdialogue).

8. IHS analysis is based on a meta-analysis of a range of studies that have occurred over a number of years. We did not anticipate material differences, plus or minus, between these various study dates and 2005 and 2012 years. For more information see IHS (2012) study.

FIGURE 3

**Well-to-wheels GHG emissions: Oil sands compared to other crude oils (Wide boundary—kg$CO_2$e per barrel of refined product)**




40326-2
Source: IHS Energy



## Results: The 2005 and 2012 US baseline

The well-to-wheels life-cycle GHG emissions for the average US crude oil for the DOE/NETL 2005 and IHS 2005 and 2012 estimates are shown in Table 2. Table 3 includes other points of comparison, such as the average oil sands refined in the United States in 2012. See Table 3 on the last page of this report for a complete summary of the GHG emissions for each individual crude. A full profile of the volume and intensity of crude oil consumed in the United States—the US crude slate, including how the average compares is shown in Figure 3. IHS calculated the GHG intensity of the average oil sands refined in the United States by estimating the mix of oil sands products pipelined to and refined in the United States in 2012—a mix of bitumen, blended bitumen, and SCO (for more detailed information on the assumptions to calculate the average oil sands refined, refer to part 5 of the Appendix to this report).

TABLE 2

**Well-to-wheels life-cycle GHG emissions of the average crude oil refined in the United States in 2005 and 2012**
(kg$CO_2$e per barrel of refined product)

| Average US barrel refined in the United States | Well-to-wheels life-cycle GHG emissions | Comments |
|---|---|---|
| 2005 IHS | 505 | |
| 2012 IHS | 502 | Less than 0.6% drop in GHG intensity of average US crude (2005–12), from IHS baseline |
| | | IHS average US crude oil baseline for 2005 is 3.7% higher than DOE/NETL |
| 2005 DOE/NETL | 487 | |

*Well-to-wheels emissions include emissions from upstream fuel used in crude production, upgrading, and refining.

Source: DOE/NETL, "Development of Baseline Data and Analysis of Lifecycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008

## GHG intensity of US tight oil production

Tight oil comes from rocks of low permeability and porosity that have hydrocarbons trapped within them. Oil is produced by drilling horizontal wells into the rock formations and fracturing them through hydraulic stimulation. This process opens pathways in the rocks that allow trapped hydrocarbons to be recovered.

To date, the most prolific regions in North America for tight oil production have been the Bakken in North Dakota and the Eagle Ford in Southwest Texas. In 2012, these regions were responsible for over 60% of US tight oil production.

Gas flaring is of particular importance when estimating the GHG emissions from crude oil. Flaring occurs when infrastructure needed to gather, process, and transport gas associated with oil production is not yet developed. This is an issue in the Bakken region since the building of new pipeline networks has not kept up with development. In addition, the remote nature of the production areas, harsh weather conditions, and difficulties in obtaining pipeline rights-of-way confound the issue. We used an estimate of 33-37% of the produced gas in the Bakken being flared. In contrast, flaring of associated gas from Eagle Ford production is a fraction of that value.

Based on the level of flaring, tight oil is often presumed to be a higher-carbon crude oil source. However, our analysis found that both Eagle Ford and Bakken crude oils have lower life-cycle GHG emissions than the average US crude oil refined—between 5% and 9% lower on a well-to-wheels basis (see Table 3).

The GHG intensity of producing the Eagle Ford crude oil is lower than that for any other crude oil estimate within our study. In addition to low extraction emissions, the Eagle Ford crude oil takes less energy (and consequently less GHG emissions) to refine into fuels.

TABLE 3

**Well-to-wheels GHG emissions of US tight oil production**
(kg $CO_2$e per barrel of refined product)

| Crude name | Production-only GHG emission | Well-to-wheels life-cycle GHG emissions | Well-to-wheels percent difference from "average US barrel refined in the United States" in 2012 |
|---|---|---|---|
| Bakken Blend | 43 | 479 | Minus 5% |
| Eagle Ford | 18 | 455 | Minus 9% |
| Average US crude oil consumed in 2012 (IHS estimate) | 44 | 502 | |

*Well-to-wheels emissions include emissions from upstream fuel used in crude production, upgrading, and refining.

Source: DOE/NETL, "Development of Baseline Data and Analysis of Lifecycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008

Because of flaring, the GHG emissions for producing Bakken crude are more than two times higher than for the Eagle Ford and in the same GHG emissions range as producing Canadian oil sands mining dilbit. However, on a life-cycle basis, the Bakken crude is still below the average crude oil because it takes less energy to refine into fuels.

For more information on the inputs and assumptions in estimating the life-cycle GHG emissions from tight oil, download the Appendix of this report at www.ihs.com\oilsandsdialogue.

**The GHG emissions rate for the average crude oil consumed in the United States should be treated as an estimate.** Using the IHS method, the 2005 average was almost 4% higher than the DOE/NETL estimate. The difference highlights the level of uncertainty in estimating the GHG emissions for the average US crude oil. There are a large number of crude oil sources, and it is difficult to get precise GHG intensity data. Further, since calculating an average compounds the uncertainty associated with each individual crude oil, the average has a greater margin of error.

**The GHG emissions rate for the average crude oil consumed in the United States was unchanged between 2005 and 2012.** Despite the dramatic change in the geographic origin of US crude supply since 2005, GHG intensity remained essentially the same because crudes oils were substituted for other supply sources that were, on average, similar in GHG intensity. Higher-carbon crudes from North Africa were replaced with less GHG-intense domestic tight oil. At the same time the GHG impact of consuming more tight oil, along with declining consumption of higher carbon Latin American and Alaskan supplies, helped offset GHG impacts from increased imports of Canadian oil sands.

**Canadian oil sands are in the same GHG intensity range as 45% of US oil supply.** Using the IHS estimate of the US average crude oil baseline for 2012 estimated in this report, crude oils transported and consumed in the United States from oil sands had life-cycle GHG emissions that ranged from 1% higher than the average crude (for mining dilbit) to 19% higher (for SAGD SCO). In 2012, 45% of US oil supply was within the same GHG intensity range as oil sands. Two-thirds of the crude oil in this range come from sources other than the Canadian oil sands, such as from Latin America, Africa, the Middle East, and parts of the United States.

## Part 4: Conclusions

The purpose of this report is to inform the dialogue surrounding the GHG emissions from US crude oil supply and Canadian oil sands. "Getting the numbers right" is especially important, considering how the GHG intensity of crude oil is factoring into policy decisions and may have direct economic implications for different crude sources.

The origin of US oil supply since 2005 has changed significantly. However, the GHG intensity of the average crude oil consumed in the United States did not materially change.

Common GHG intensity baselines—such as the average crude consumed in the United States—provide a useful reference point for comparisons. However, they should be used with caution. They are theoretical values to enable comparisons, not absolute numbers. There are simply too many crude oils consumed in the United States to accurately track and quantify emissions for each. The almost 4% difference between the IHS and DOE/NETL results indicates the possible margin of error in estimating the GHG emissions for the average crude oil.

Considering the uncertainty in measuring GHG emissions, it is important to avoid common pitfalls in using average baselines. The average crude should not be used as a reference point to estimate the incremental GHG emissions associated with greater US imports of crude derived from the Canadian oil sands. This approach is flawed since the oil sands will not replace the average crude oil; rather, they will replace other heavy crude oils.

Finally, despite commonly held views that oil sands are the highest-carbon crude oil, 45% of US oil supply falls within the same GHG intensity range as oil sands. Two-thirds of these crudes are coming from sources other than the Canadian oil sands, such as from Latin America, Africa, the Middle East, and some US domestic production.

## Report participants and reviewers

IHS hosted a focus group meeting in Washington, DC, on 22 October 2013 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 is exclusively responsible for the content of this report.

Alberta Department of Energy

Alberta Innovates—Energy and Environment Solutions

American Petroleum Institute

BP Canada

Canadian Association of Petroleum Producers

Canadian Natural Resources Limited

Canadian Oil Sands Limited

Cenovus Energy Inc.

Center for Strategic and International Studies (CSIS)

ConocoPhilips Company

Enbridge Inc.

Nexen Energy ULC

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

Lawrence National Centre for Policy and Management, Ivey Business School, Western University

Natural Resources Canada

RAND Corporation

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

Woodrow Wilson International Center For Scholars (Wilson Institute)

## IHS energy team

**Jackie Forrest,** former Senior Director, IHS Energy. Her recent contributions to oil sands research include reports on the life-cycle emissions from crude oil, the impacts of low-carbon fuel standards, effects of US policy on oil sands, and future markets for Canadian oil sands. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University. Ms. Forrest is now a Vice-President at ARC Financial Corp.

**Cheryl Dereniwski**, Managing Director, IHS Energy, leads the Upstream Consulting practice in Canada. With 20 years of oil and gas industry experience, she has diverse business advisory and technical expertise, working in areas related to strategic planning, exploration and development, production operations, and corporate services across upstream, midstream, and downstream segments. She has worked with a wide range of clients, helping them to assess the impact of industry and market trends on future growth strategies, optimize capital investment decisions, improve organizational alignment to business function, streamline business processes, and identify and evaluate acquisition targets. More recently she has also been involved in assessing life-cycle emissions from crude oil. Before joining IHS, Ms. Dereniwski worked at Deloitte Consulting, Advantage Energy Services, and Imperial Oil. She is a professional engineer and holds a Bachelor of Science (honors) from Queens University.

**Kevin Birn,** Director, IHS Energy Insight, heads up the IHS Oil Sands Energy Dialogue. Recent contributions to oil sands research include analysis of the marine transport of oil sands crude, upgrading economics, and the future markets for oil sands. Prior to joining IHS, Mr. Birn worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada, helping to inform early Canadian oil sands policy. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US Secretary of Energy. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta.

TABLE 1

## Well-to-wheels GHG emissions for oil sands and conventional crude oils—Wide boundary results

($kgCO_2e$ per barrel of refined product)

| | | Tight boundary | | | | | | Wide boundary | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Crude name | Source of production emissions | Crude production (includes venting and flaring, dilbit production, mine face, and tailings) | Upgrading | Crude transport | Crude refining | Refined product transport | Refined product combustion | Crude production: Upstream fuel | Upgrading: Upstream fuel | Crude refining: Upstream fuel | Well-to-tank (wide boundary) | Well-to-wheels (wide boundary) | Well-to-wheels percent difference from "average US barrel refined in the United States" IHS 2012 |
| Cameroon Lokele | CARB (2012) | 136 | 0 | 9 | 53 | 2 | 385 | 0 | 0 | 14 | 214 | 599 | 19% |
| Canadian oil sands: SAGD SCO | IHS (2012) | 65 | 51 | 8 | 46 | 2 | 385 | 23 | 3 | 15 | 213 | 598 | 19% |
| Canadian oil sands: CSS bitumen | IHS (2012) | 89 | | 12 | 62 | 2 | 385 | 23 | | 19 | 206 | 591 | 18% |
| Venezuela Petro zuata | IHS (2012) | 22 | 103 | 4 | 52 | 2 | 385 | 0 | 3 | 14 | 200 | 585 | 16% |
| US: Average California Heavy | IHS (2012)—average | 102 | 0 | 4 | 55 | 2 | 385 | 12 | 0 | 16 | 190 | 575 | 15% |
| Canadian oil sands: SAGD bitumen | IHS (2012) | 65 | 0 | 12 | 62 | 2 | 385 | 23 | 0 | 19 | 183 | 568 | 13% |
| Canadian oil sands: CCS dilbit | IHS (2012)—CCS dilbit | 74 | 0 | 10 | 54 | 2 | 385 | 17 | 0 | 17 | 173 | 558 | 11% |
| Canadian oil sands: Average produced (2012) | IHS (2014) | 49 | 25 | 10 | 54 | 2 | 385 | 14 | 1 | 16 | 172 | 557 | 11% |
| Canadian oil sands: Mining SCO | IHS (2012) | 28 | 51 | 8 | 46 | 2 | 385 | 10 | 3 | 15 | 163 | 548 | 9% |
| Average oil sands refined in the United States (2012) | IHS (2014) | 50 | 15 | 9 | 53 | 2 | 385 | 12 | 1 | 16 | 160 | 545 | 9% |
| Venezuela Boscan | CARB (2012) | 66 | 0 | 4 | 62 | 2 | 385 | 6 | 0 | 18 | 158 | 543 | 8% |
| Canadian oil sands: SAGD dilbit | IHS (2012) | 57 | | 10 | 54 | 2 | 385 | 17 | 0 | 17 | 156 | 541 | 8% |
| US: Alaska North Slope (ANS CARB) | CARB (2012) | 83 | 0 | 4 | 41 | 2 | 385 | 0 | 0 | 14 | 145 | 530 | 6% |
| Canadian Bitumen Blend | IHS (2012)—average | 42 | 13 | 10 | 51 | 2 | 385 | 8 | 1 | 16 | 143 | 528 | 5% |
| Nigeria Bonny Light | IHS (2012) | 77 | 0 | 9 | 39 | 2 | 385 | 0 | 0 | 14 | 141 | 526 | 5% |
| Canadian oil sands: Mining bitumen (PFT) | IHS (2012) | 29 | | 12 | 62 | 2 | 385 | 10 | | 19 | 134 | 519 | 3% |
| Iraq Basrah Light | IHS (2012) | 60 | 0 | 9 | 43 | 2 | 385 | 0 | 0 | 14 | 128 | 513 | 2% |
| Canadian oil sands: Primary CHOPS | IHS (2012) | 38 | 0 | 10 | 60 | 2 | 385 | 0 | 0 | 18 | 128 | 513 | 2% |
| US: Mars | IHS (2012) | 60 | 0 | 4 | 42 | 2 | 385 | 0 | 0 | 14 | 122 | 507 | 1% |
| Venezuela–Bachaquero | IHS (2012) | 35 | | 4 | 64 | 2 | 385 | | | 18 | 122 | 507 | 1% |
| Canadian oil sands: Mining dilbit (PFT) | IHS (2012) | 31 | | 10 | 54 | 2 | 385 | 7 | 0 | 17 | 121 | 506 | 1% |
| Angola Girassol | IHS (2012) | 51 | 0 | 9 | 44 | 2 | 385 | 0 | 0 | 14 | 120 | 505 | 1% |
| Average US barrel refined in the United States (2005 IHS est.) | | 49 | 3 | 6 | 45 | 2 | 385 | 1 | 0 | 14 | 120 | 505 | 1% |
| Russian ESPO | CARB (2012) | 55 | 0 | 9 | 40 | 2 | 385 | 0 | 0 | 14 | 119 | 504 | 0% |

TABLE 1

## Well-to-wheels GHG emissions for oil sands and conventional crude oils—Wide boundary results

($kgCO_2e$ per barrel of refined product)

| Crude name | Source of production emissions | Crude production (includes venting and flaring, dilbit production, mine face, and tailings) | Upgrading | Crude transport | Crude refining | Refined product transport | Refined product combustion | Crude production: Upstream fuel | Upgrading: Upstream fuel | Crude refining: Upstream fuel | Well-to-tank (wide boundary) | Well-to-wheels (wide boundary) | Well-to-wheels percent difference from "average US barrel refined in the United States" IHS 2012 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Tight boundary | | | | | | Wide boundary | | | | | |
| Average US barrel refined in the United States (2012 IHS est.) | | 44 | 4 | 6 | 45 | 2 | 385 | 1 | 0 | 14 | 117 | 502 | |
| North Sea Mariner | IHS (2012) | 23 | 0 | 9 | 64 | 2 | 385 | 0 | 0 | 18 | 116 | 501 | 0% |
| Mexico Maya | IHS (2012) | 42 | 0 | 4 | 52 | 2 | 385 | 0 | 0 | 14 | 114 | 499 | -1% |
| Ecuador Napo | CARB (2012) | 38 | 0 | 4 | 55 | 2 | 385 | 0 | 0 | 14 | 113 | 498 | -1% |
| Angola Dalia | CARB (2012) | 37 | 0 | 9 | 51 | 2 | 385 | 0 | 0 | 14 | 112 | 497 | -1% |
| Russian Urals | IHS (2012) | 47 | 0 | 9 | 40 | 2 | 385 | 0 | 0 | 14 | 111 | 496 | -1% |
| Ecuador Oriente | IHS (2012) | 46 | 0 | 4 | 45 | 2 | 385 | 0 | 0 | 14 | 110 | 495 | -1% |
| Kuwait Eocene | IHS (2012) | 25 | 0 | 9 | 56 | 2 | 385 | 0 | 0 | 18 | 109 | 494 | -2% |
| Australia Pyrenees | CARB (2012) | 30 | 0 | 9 | 54 | 2 | 385 | 0 | 0 | 14 | 108 | 493 | -2% |
| Colombia Castilla | CARB (2012) | 29 | 0 | 4 | 55 | 2 | 385 | 0 | 0 | 18 | 108 | 493 | -2% |
| Iraq Kirkuk | IHS (2012) | 45 | 0 | 9 | 37 | 2 | 385 | 0 | 0 | 14 | 106 | 491 | -2% |
| Brazil Marlim | CARB (2012) | 32 | 0 | 4 | 54 | 2 | 385 | 0 | 0 | 14 | 106 | 491 | -2% |
| Angola Plutonio | CARB (2012) | 41 | 0 | 9 | 39 | 2 | 385 | 0 | 0 | 14 | 105 | 490 | -2% |
| Average US barrel refined in the United States (2005 DOE/NETL) | | 36 | | 6 | 43 | 2 | 385 | 0 | 0 | 14 | 102 | 487 | -3% |
| Kuwait Ratawi | CARB (2012) | 25 | 0 | 9 | 50 | 2 | 385 | 0 | 0 | 14 | 100 | 485 | -3% |
| Canadian Mixed Sweet | CARB (2012) | 36 | 0 | 10 | 37 | 2 | 385 | 0 | 0 | 14 | 99 | 484 | -4% |
| Colombia Vasconia | CARB (2012) | 30 | 0 | 4 | 48 | 2 | 385 | 0 | 0 | 14 | 98 | 483 | -4% |
| Bakken Blend | IHS 2014 | 43 | 0 | 4 | 31 | 2 | 385 | 0 | 0 | 14 | 94 | 479 | -5% |
| Arab Light | IHS (2012) | 28 | 0 | 9 | 40 | 2 | 385 | 0 | 0 | 14 | 93 | 478 | -5% |
| Trinidad Calypso | CARB (2012) | 36 | 0 | 4 | 35 | 2 | 385 | 0 | 0 | 14 | 91 | 476 | -5% |
| Arab Medium | IHS (2012) | 22 | 0 | 9 | 42 | 2 | 385 | 0 | 0 | 14 | 89 | 474 | -6% |
| US: Average crude oil (DOE/NETL) | IHS (2012) | 25 | 0 | 4 | 43 | 2 | 385 | 0 | 0 | 14 | 88 | 473 | -6% |
| North Sea Ekofisk | IHS (2012) | 22 | 0 | 9 | 35 | 2 | 385 | 0 | 0 | 14 | 82 | 467 | -7% |
| North Sea Forties | IHS 2014 | 19 | 0 | 9 | 31 | 2 | 385 | 0 | 0 | 14 | 75 | 460 | -8% |
| Eagle Ford Tight Oil | IHS 2014 | 18 | 0 | 4 | 33 | 2 | 385 | 0 | 0 | 14 | 70 | 455 | -9% |

Notes: 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 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 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 diliuent 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.

Source: IHS Energy meta-analysis sourcing data from IHS Energy (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

IHS Markit™

# Greenhouse gas intensity of oil sands production

## Today and in the future

September 2018

Canadian Oil Sands Dialogue | **Strategic Report**

# Contents

# Greenhouse gas intensity of oil sands production

Today and in the future

## About this report

**Purpose.** Since 2009, IHS Markit has provided research on issues surrounding the development of the Canadian oil sands. IHS Markit has completed five public studies on the greenhouse gas (GHG) emission intensity of oil sands crude and how the intensity compares with other crudes and the average crude oil refined in the United States. Building on our prior work, IHS Markit constructed a bottom-up model using publicly available data of individual emission sources within oil sands production facilities to estimate historical emissions intensity. Using this model, we established a baseline intensity for each emission source. This allowed us to estimate the impact of specific performance improvements to individual emission sources on aggregate industry emission intensities over time. The results provide a detailed review of the history of upstream oil sands GHG emissions, how they have changed, what factors have influenced these changes, and how emissions could evolve to 2030.

**Context.** This report is part of a series of reports from the IHS Markit Canadian Oil Sands 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.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. A bottom-up oil sands–specific GHG emission intensity model was purposely built for this analysis. Historical performance was derived using publicly available regulatory data. Future estimates relied on historical baselines, individual data requests from select oil sands operations, and IHS Markit expertise. Detailed appendices are included. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

**Structure.** This report has five sections and two appendixes.

- Introduction
- The IHS Markit method
- The history of oil sands GHG emission intensity
- Mapping the future course of oil sands GHG emission intensity to 2030
- Concluding remarks and comparisons
- Appendix A
- Appendix B

## Key implications

In the wake of expanding and increasingly stringent climate policy, as well as greater questions about energy transition, interest in the greenhouse gas (GHG) emission intensity of oil sands extraction has never been greater. Unlike prior IHS Markit studies that focused on emissions over the entire life cycle (from well to wheels), this study presents a detailed bottom-up analysis of historical upstream GHG emission intensity and provides a view to 2030.

- **Different system boundaries (which define which emissions are counted) result in differences among GHG estimates.** Consistent with prior IHS Markit life-cycle analysis, in addition to direct emissions, upstream emissions associated with the production of imported fuels are included, while emissions associated with power exported to the grid are deducted from GHG intensity estimates.

- **The average intensity of oil sands extraction has fallen 21% since 2009—a story dominated by mined oil sands.** From 2009 to 2017, the GHG intensity of mined oil sands fell by more than 25%, principally from the ramp-up of less GHG-intensive operations. In situ operations remained relatively flat as reductions in natural gas intensity were offset by nearly equivalent reductions in the intensity of exports of surplus electrical power to the grid.

- **New modes of oil sands production are less carbon intensive and already contributing to intensity reductions.** Newer mined diluted bitumen operations are different—coming in at roughly half the upstream GHG intensity of legacy mining operations, which convert bitumen into lighter synthetic crude oil. Two proposed thermal in situ projects aim to use solvent to aid in production, lowering the GHG intensity of extraction.

- **By 2030, the GHG intensity of oil sands extraction could be 16–23% below 2017 levels—more than one-third less than in 2009.** The deployment of commercial and near-commercial technologies and efficiencies could result in a 17–27% reduction in the GHG intensity of steam-assisted gravity drainage operations (which accounted for 45% of oil sands supply in 2017) by 2030 and a 15–20% reduction in the GHG intensity of mined oil sands. On a full life-cycle basis (inclusive of emissions from production to combustion), these upstream intensities would place these sources within 2–4% and 5–7% of the average crude oil refined in the United States, respectively.

- **Among oil sands developments, the range of upstream GHG emissions intensities are diverse, a factor that a focus solely on the averages will miss.** The use of averages in GHG estimation can be informative, but distribution matters as well. In 2017, the upstream GHG emissions intensity range of oil sands facilities spanned 88 kilograms (kg) of carbon dioxide equivalent ($CO_2e$) per bbl (from 39 to 127 kg$CO_2$e/bbl), and as a result, any one facility may not be well represented by the average. On a full life-cycle GHG emission intensity basis (wells-to-wheels), the range of oil sands intensities in 2017 goes from approximately 1% below to 16% above the average crude oil refined in the United States.

- **The potential for more transformational changes in oil sands extraction technology exists, and with them a more radical impact on emissions.** With few exceptions, the IHS Markit oil sands GHG emission outlook does not include these transformational changes in extraction technology. Yet, many such technologies are advancing, and with them greater reductions in GHG intensity should be expected.

# Greenhouse gas intensity of oil sands production

Today and in the future

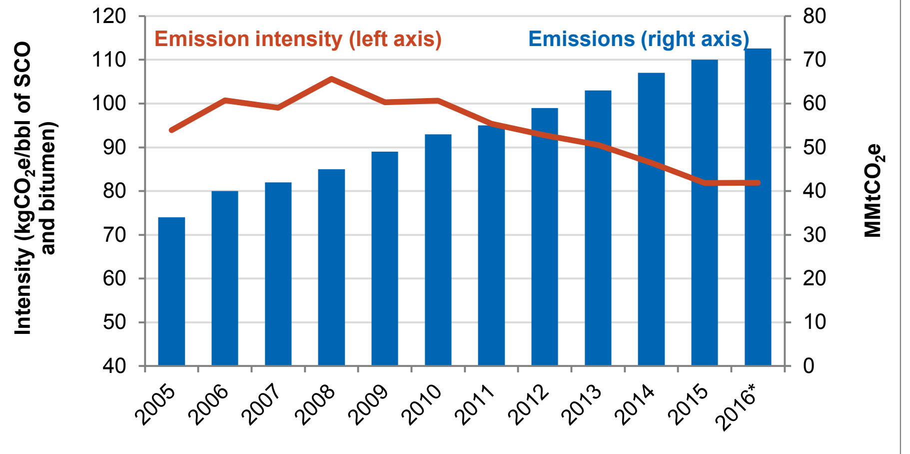
**Kevin Birn,** Vice President[1]

## Introduction

Over the more than 50 years since commercial oil sands extraction began, production has almost always increased. Along with rising production, absolute GHG emissions have also increased, but at a declining rate per barrel. According to Canada's National Inventory Report (NIR), which captures direct emissions, between 2005 and 2016 annual oil sands emissions increased 39 million metric tons of carbon dioxide equivalent ($MMtCO_2e$), to 73 $MMtCO_2e$. Meanwhile, oil sands production expanded 1.4 MMb/d, to 2.4 MMb/d, making Canada the sixth-largest producer of crude oil globally (Canada, in 2017, subsequently overtook China and became the fifth largest).[2] This change equates to a direct emission intensity reduction of 13% per barrel over the same period (see Figure 1).[3]

Figure 1

Canadian oil sands GHG emissions: Absolute ($MMtCO_2e$/bbl) and intensity ($kgCO_2e$/bbl)




*The 2016 Fort McMurray wildfire led to significant upstream oil sands disruption.
Source: IHS Markit, Alberta Energy Regulator (AER), Canada's NIR 2018



Growth in oil sands emissions, within the context of a relatively small population (in 2017, Canada was the 38th-most-populous nation globally) and a fairly low GHG-intensive power sector (four-fifths of power generation is nonemitting), has contributed to oil sands accounting for a greater share of overall national emissions.[4] Environment and Climate Change Canada estimates that oil sands accounted for about 10% of national emissions in 2016.[5]

Numerous policies have advanced in recent years to try to limit and reverse oil sands emission growth while minimizing the economic impacts. These include an intensity-based carbon pricing mechanism intended to protect trade-exposed sectors and limit carbon leakage; an absolute cap on oil sands GHG emissions at 100 $MMtCO_2e$ per year; and a national pricing policy that aims to ensure the price of emissions in Canada will rise to $50 per metric

1. Special thank you to former IHS Markit colleague Hossein Safaei, the original architect of IHS Markit upstream oil sands greenhouse gas (GHG) intensity models.

2. The latest data available at time of completion of this report were for 2016. Source: Environment and Climate Change Canada, *National Inventory Report 1990–2016: Greenhouse Gas Sources and Sinks in Canada,* April 2018, https://unfccc.int/documents/65715, retrieved 16 July 2018.

3. GHG intensity is estimated by dividing total direct oil sands emissions derived from Canada's NIR 2018 by IHS Markit oil sands production (upgraded bitumen, such as synthetic crude oil [SCO], and unupgraded bitumen).

4. Population data sourced from the United Nations, Department of Economic and Social Affairs, Population Division, "World Population Prospects 2017," https://esa.un.org/unpd/wpp/, retrieved 17 August 2018. For more information on Canadian national emissions and power grid intensity, see the IHS Markit Strategic Report *The State of Canadian and US Climate Policy.*

5. Canada's NIR reports direct oil sands emissions at 73 $MMtCO_2e$ in 2016 and total Canadian emissions at 704 $MMtCO_2e$. Source: Environment and Climate Change Canada, *National Inventory Report 1990–2016: Greenhouse Gas Sources and Sinks in Canada,* April 2018, https://unfccc.int/documents/65715, retrieved 16 July 2018.

ton of $CO_2e$ by 2022.[6] Governments and industry are also investing in research and technology to lower emission intensity.

This report explores the past and future GHG intensity of upstream oil sands extraction. The report begins with a review of the study purpose, method, and uncertainties in estimating oil sands emission intensity. This discussion is followed by the results of the assessment of historical upstream oil sands emission intensity from 2008 or 2009 to 2017 and then the outlook for future emission trends from 2018 to 2030. The report concludes with a discussion of the implications and comparison on a full life-cycle basis.

The report includes two appendixes: Appendix A provides additional detail on the results and Appendix B provides a detailed description of our methodology.

Throughout this report, numerous oil sands terms are referenced. For more information, please refer to the box "Oil sands GHG primer."

## Oil sands GHG primer

Accounting for approximately 3.8% of global supply in 2017, the oil sands are perhaps the most scrutinized source of crude oil in the world.* This attention is due, at least in part, to the sheer scale of the resource potential and concerns about environmental impacts. Current estimates place the amount of remaining economically recoverable reserves in the oil sands at 164 billion bbl, 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 crude oil with high viscosity. Accessing, separating, and marketing bitumen from the oil sands require energy, resulting in GHG emissions. The intensity of upstream production emissions depends on the reservoir characteristics, the extraction method, and each facility's unique configuration (performance and energy sources). Two forms of extraction dominate: mining and in situ.

**Mining.** About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process, the overburden (vegetation, soil, clay, and gravel) is removed and used in associated infrastructure, such as roads and embankments, or stockpiled for later use in reclamation. The layer of oil sands ore is excavated using large shovels that scoop the material, which is then transported by truck to a processing facility. The ore is crushed or sized and then mixed with warm water and agitated, which causes the bitumen to separate. The energy used to power the vehicles involved in the mining process comes from fossil fuels, as does the heat used in the separation plant. In 2017, just less than two-fifths of oil sands supply (which can include diluent) came from mining; but, by 2030, as other forms of production are expected to outpace mining growth, mining's share of output will fall to less than one-third. There are two forms of mining extraction:

- **Integrated mines or mined SCO.** Legacy mining operations invested in and constructed heavy oil processing units upstream in the oil sands, which are often found integrated downstream into complex heavy oil refineries. Known as upgraders, these specialized processing units convert bitumen into a lighter SCO. As a result, upgraders add to upstream "mined SCO" emissions, which otherwise would occur downstream.

*The estimate is based on total oil sands supply, inclusive of diluents imported into and used in the creation of bitumen blends in 2017, compared with total global crude production as marketed from the IHS Markit Annual Strategic Workbook 2018. On a production basis (without diluent), oil sands accounted for approximately 3.4% of the global crude oil system. Both estimates do not include NGLs, biofuels, or other liquids.

**AER, ST98: 2018: *Alberta's Energy Reserves & Supply/Demand Outlook: Executive Summary*, p. 7, https://www.aer.ca/documents/sts/ST98/ST98-2018_Executive_Summary.pdf, retrieved 30 May 2018.

6. For more information on the oil sands GHG emission cap, see "Bill 25: Oil Sands Emissions Limit Act," www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_29/session_2/20160308_bill-025.pdf, retrieved 20 July 2018; and for more information on the Pan-Canadian Framework, see "Pan-Canadian Framework on Clean Growth and Climate Change," Canada.ca, www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework.html, retrieved 30 July 2018.

### Oil sands GHG primer (continued)

- **Unintegrated mines or mined dilbit (PFT).** In more recent years, two new mining operations have been completed that do not feature an integrated upgrader. Through a process known as paraffinic froth treatment (PFT), some of the heaviest components found in bitumen are precipitated out. The recovered bitumen is then diluted with lighter hydrocarbons (typically a natural gas condensate) and shipped to market as a bitumen blend or specifically a diluted bitumen (dilbit). This process avoids the energy associated with upgrading, reducing upstream GHG production emissions. However, the marketed dilbit is thereby more GHG intensive to refine, increasing downstream refining emissions. Still, on a net or full life-cycle basis, mined dilbit is lower than mined SCO (see "Concluding remarks and comparisons" section). The PFT process has also been found to produce a modestly higher-quality bitumen and results in a dilbit product with a ratio of approximately four-fifths bitumen to one-fifth condensate.

**In situ.** About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. These deposits are the largest-growing source of oil sands production. In 2017, more than three-fifths of oil sands supply came from in situ operations, and, by 2030, this amount could exceed two-thirds. Both primary and thermal extraction methods are deployed in situ. The primary extraction method is much more akin to conventional oil production and in 2017 accounted for about 6% of supply (including diluent). However, as growth of other sources of supply continues to outpace primary extraction, its share of supply is expected to fall, reaching about 4% by 2030. Thermal production accounts for more than half of oil sands supply today (and nearly 90% of in situ supply). Thermal methods inject steam into the reservoir to lower the viscosity of the bitumen and allow it to flow to the surface. Natural gas is used to generate the steam, which results in GHG emissions. Bitumen produced from in situ operations is also too viscous to permit transport by pipeline and must be diluted with lighter hydrocarbons, making a bitumen blend. The most common blend is dilbit with a ratio of 70% bitumen to 30% condensate. There are two dominant forms of thermal in situ extraction.

- **Steam-assisted gravity drainage (SAGD)** is the fastest-growing method, accounting for more than 45% of supply in 2017, and is expected to dominate growth, accounting for 56% of supply by 2030.

- **Cyclic steam stimulation (CSS)** was the first thermal process used to commercially recover oil sands in situ. CSS currently makes up 10% of total supply, and growth in other sources of supply is expected to outpace CSS, and its share of total output could fall to 7% by 2030.

## The IHS Markit method

This section discusses the scope of the study, our estimation method, and comparability and uncertainty associated with our results.

### Study scope

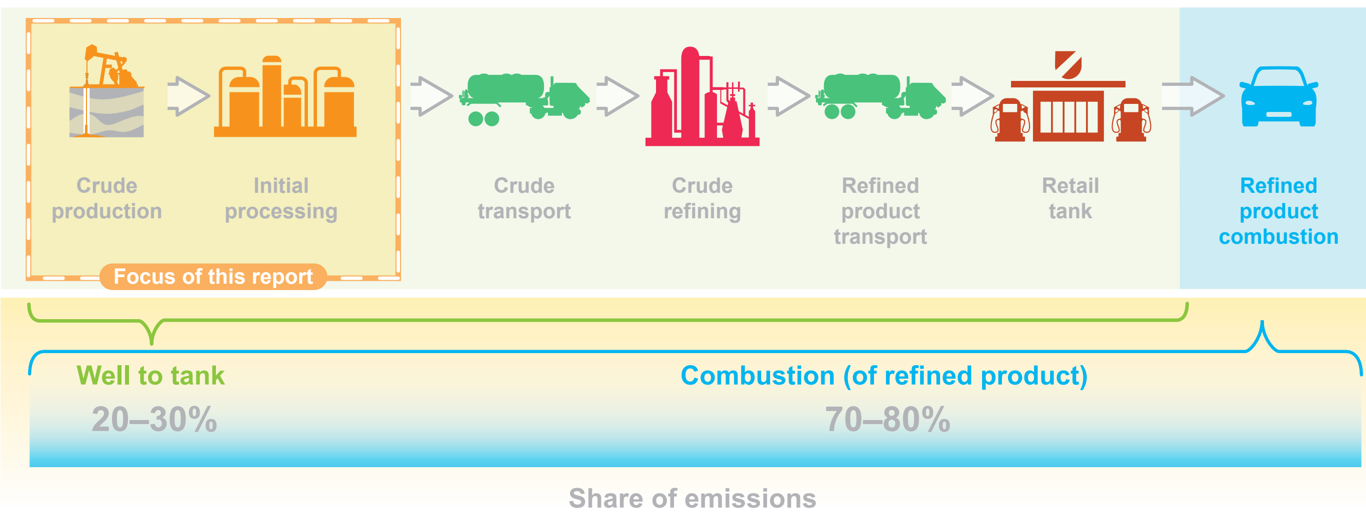
GHG emissions occur over the entire life of liquid hydrocarbon fuel, from production, refining, transport to markets, and finally combustion (see Figure 2). The production, refining, and marketing phases make up a relatively small share of overall emissions. Most emissions—70–80%—occur at combustion.

IHS Markit has performed extensive life-cycle analysis of the GHG intensity of oil sands crude and how the intensity compares with other crudes and the average crude oil refined in the United States ("the US average"). IHS Markit has consistently found the GHG intensity of oil sands–derived crude oil to be above the US average, but we have also found it to be within the range of other crude oils. In our last study, released in 2014, we found oil sands crude ranged from 1% to 19% higher than the US average, with more than 45% of the crude oil processed in the United States fitting within that range.[7] We also have found that sensitivity to assumptions and data limitations lead to uncertainty associated with estimating GHG emissions.

The focus of this study is oil sands extraction and initial processing—upstream emissions (as highlighted in Figure 2). The results may also be viewed as the Canadian-centric component, because most oil sands production is exported. The analysis includes a historical bottom-up analysis of energy and fuel use derived from publicly available data and data requests from governments and regulators. Furthermore, because our approach allowed us to establish a historical GHG emission intensity by fuel or emission source, such as natural gas or diesel, we could measure the aggregate impact of efficiency improvements over time on individual fuel or emission sources as well as fluctuations in production. Our outlook was complemented with additional publicly available government data and data requests of specific facilities in production ramp-up. The result is a very detailed analysis of a possible future trajectory of upstream oil sands GHG emission intensity to 2030.

Figure 2

Life-cycle GHG emissions of petroleum fuels




Source: IHS Markit

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## Estimating historical oil sands emission intensities

We estimated historical oil sands emission intensities for mining and in situ thermal operations. Estimates of primary, experimental, or enhanced oil recovery (EOR) techniques used in the oil sands region were included in the total oil sands industry average (shown in the final section of the report) using estimates from prior IHS Markit reports and other analysis, but are not modeled in this study.

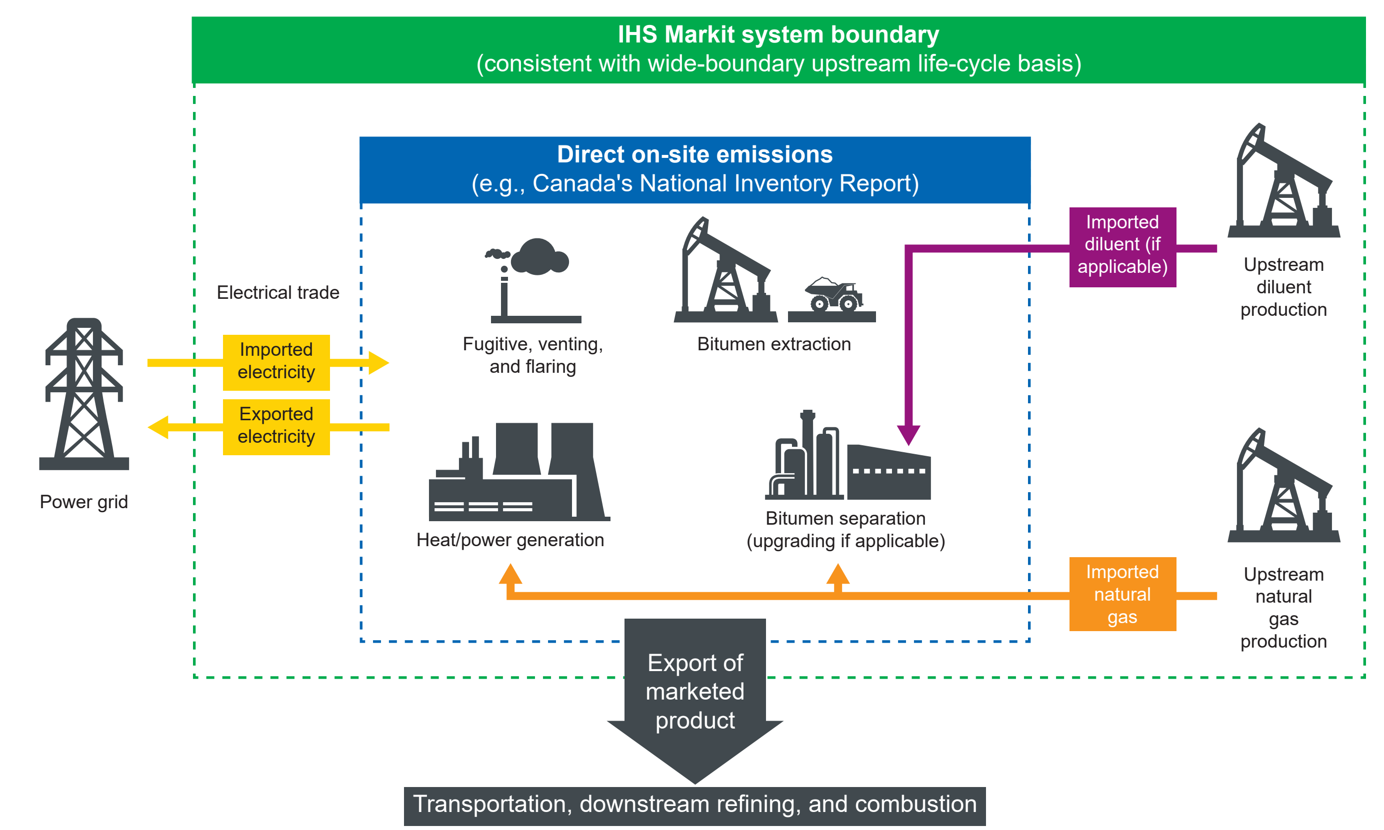
Differences in data and production processes necessitate distinct modeling approaches for mining and in situ operations. Data limitations affect the period for which we could make historical estimates: 2008–17 for mining operations and 2009–17 for in situ operations. IHS Markit chose system boundaries (the scope of emissions captured/included) consistent with prior research to allow for results to be compared and integrated with prior IHS Markit life-cycle assessments. As a result, in addition to direct emissions, emissions associated with upstream production of fuel, such as natural gas or diluent used in the creation of diluted bitumen, as well

7. IHS Markit estimated that on a full life-cycle basis, from wells to wheels, oil sands ranged from 506 kg of carbon dioxide equivalent ($CO_2e$) per bbl to 598 kg$CO_2e$/bbl of refined product, while the average GHG intensity of crude oil refined in the United States was estimated to be 502 kg$CO_2e$/bbl of refined product in 2012. Source: IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil.*

as the import and export of electricity that can arise from the use of cogeneration, were included. See Figure 3 for a depiction of IHS Markit system boundaries.

Figure 3

**System boundaries**




Source: IHS Markit

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We estimated historical emissions by converting energy use reported to regulators and environmental departments in Alberta to GHG emissions. To this, we added indirect emissions from upstream production of natural gas used to generate heat and electricity and from diluent (which we assumed to be condensate) used in operations that market dilbit. Electrical imports and exports were credited or debited against oil sands GHG emissions at a rate equivalent to combined-cycle natural gas combustion. Electrical credits or surplus electricity exported to the grid can result from an oil sands facility use of cogeneration. Estimating the impact of cogeneration can complicate oil sands emission intensity estimating. For more information on cogeneration, see the box “Allocating cogeneration emissions.”

## Allocating cogeneration emissions

Electricity imports and exports complicate emission calculations. Since electricity crosses the system boundary, energy and thus emissions can enter and leave the system. GHG emission estimates can vary depending on the method used to treat electricity trade—including the value or credit of electricity-associated emissions.

Oil sands plants need both heat (steam) and electricity. Although there is nothing inherent in their processes, mining has historically been fairly energy balanced (with neither large imports nor exports of electricity), while in situ operations have been large electrical exporters (on an intensity basis).

## Allocating cogeneration emissions (continued)

IHS Markit chose to allocate GHG emissions associated with electrical trade according to energy balance—only energy consumed within the plant. Deducting net power exports against facility emissions (assigning a credit for exported power against facility emissions) is an accepted methodology in GHG estimation (although the value of the credit is an area of difference of opinions).[1]

For this study, the value of the electrical trade was 440 $kgCO_2e/MWh$, which aligns with the combined value of a combined-cycle natural gas generation unit (370 $kgCO_2e/MWh$) plus the associated upstream GHG emissions from the natural gas needed to fire the unit.[2] This rate was chosen because a combined-cycle natural gas generation unit was viewed as the most likely marginal source of power in Alberta. Using the Alberta grid average would have been another method but would have nearly doubled the credit value because of Alberta's current reliance on coal-fired generation. However, this value would be expected to fall as Alberta decarbonizes its grid, adding an additional layer of complexity and debate to our modeling.

1. This choice is also consistent with Alberta's Carbon Competitiveness Incentive Regulation GHG accounting rules: https://www.alberta.ca/carbon-competitiveness-incentive-regulation.aspx.

2. Upstream natural gas emissions are discussed in Appendix B.

Results are presented as the average of the marketed product by extractive technology to best represent the GHG intensity of production that is sold and processed by downstream refineries. Our results included mined SCO average, mined dilbit (PFT), total mining average, SAGD dilbit, and CSS dilbit.

A summary of the IHS Markit historical emission estimation method is included in the box "Historical oil sands mining emissions" and the box "Historical oil sands in situ emissions." A detailed methodology is included in Appendix B.

## Estimating historical oil sands mining emissions

The AER has provided data on energy consumption, production, and electrical balance for each mining facility since 2008. These data include use of natural gas, produced gas, petroleum coke, and electrical imports/exports as well as flaring.*

In addition to these data, information on mobile mine fleet diesel consumption and estimates of fugitive emissions were obtained from the Alberta Environment and Parks Specified Gas Emitters Regulation (SGER) database up to 2015. Diesel consumption was further refined with data requests from individual operations.**

Emission factors were used to convert energy use to GHG emission estimates and then divided by production to arrive at emission and/or energy intensities. We made adjustments to the natural gas conversion factor to incorporate upstream natural gas production. Upstream diluent production emissions were included based on a simplified blending assumption per barrel of bitumen output. For more information, see Appendix B.

Electrical imports and exports were credited or debited against oil sands operations at a rate equivalent to combined-cycle natural gas combustion, as discussed in the box "Allocating cogeneration emissions."

*"ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39, retrieved 4 April 2018.

**Alberta Environment and Parks, SGER database, obtained upon request, accessed 2016.

### Estimating historical oil sands mining emissions (continued)

We estimated emission intensity for each mining project individually and summed them to develop an industry weighted average for mined SCO, mined dilbit (PFT), and total mined production.

Special cases were incorporated into our estimate and model, such as the impact of one mine that operates an integrated carbon capture unit. More information is available in Appendix B.

### Estimating historical oil sands in situ emissions

The AER provides data on in situ steam demand and efficiency as recorded in steam-to-oil ratios (SOR).* The SOR measures the equivalent volume of steam required to produce 1 barrel of oil. Because natural gas is used exclusively to meet steam demand, the SOR is a good measure of efficiency and GHG emission intensity.

Although the SOR can act as a good estimate for steam and thus natural gas consumption, some electricity is required. Electrical intensity of production was obtained from the Alberta Environment and Parks SGER database, which provides historical estimates of the share of cogeneration to heat and electricity as well as efficiency. We used these values to estimate electrical demand per barrel. A survey of installed cogeneration capacity resulted in an estimate of total generation capacity. A surplus of electricity resulted in a credit, while a deficit was debited against facility emissions. The value of the credit was based on the equivalent to the best available natural gas power generation unit, plus the emissions associated with the upstream production of natural gas consumed—consistent with mining assumptions.

Like mines, indirect emissions from the import and use of natural gas for heat and electricity and diluents were included and converted to emissions at the same rate as mines.

Please note that we needed to estimate heat from cogeneration and heat from boilers separately for later use in estimating future emissions. We estimated this using data on heat from cogeneration obtained from the SGER database. Any difference between total steam demand and steam from cogeneration was assumed to come from natural gas–fired boilers.

All the sources were summed and then converted into an industry weighted average intensity estimate. More information is available in Appendix B.

*"ST53: Alberta In Situ Oil Sands Production Summary," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53, retrieved 30 May 2018.

## Estimating future oil sands emission intensities

IHS Markit sought to understand the impact of additional efficiency improvements and the deployment of commercial or near-commercial technologies on oil sands GHG emission intensity over time. Critical factors included not only the potential technologies and efficiencies but also the pace of adoption and future growth.

The first part of the report establishes historical baselines of emission intensity by fuel and/or emission source for oil sands operations based on government data. Using these baselines, IHS Markit was able to estimate the impact on future emission intensities of efficiency improvements on individual fuel and/or emission streams in the IHS Markit production outlook to 2030. This impacted oil sands mining and in situ projects differently.

Mining operations baselines by fuel or emission source were carried forward based on the last year of operation. Project operators that have recently completed mining projects or are about to undertake work expected to impact operations were consulted regarding their expected operational energy supply and demand following completion of their work and/or normalization of operations. IHS Markit currently does not have any entirely new mining projects commencing operations prior to 2030.

The key indicator for in situ performance is steam intensity, or the SOR. The average of the past three years of operation was used to establish the baseline SOR of existing facilities in our outlook to 2030.[8] Regulatory applications were used to establish baselines for new facilities, while a combination of regulatory applications and past performance was used for expansion projects.

After establishing a baseline of operations for each facility (mining and in situ), we layered new technologies and efficiencies onto specific fuel, energy, and/or emission streams. Considerable detail was put into modeling the potential pace of deployment. For example, in situ technologies in which steam could be displaced were not universally applied, with the potential benefit limited to new wells. Projects that proposed to incorporate similar technologies in their application to what IHS Markit was modeling were not allowed to benefit from IHS Markit assumptions. A discussion of modeled improvements is included later in the report and in Appendix B.

To be certain, each facility is unique, and there is an array of advancing technologies that could materially alter future oil sands extraction and emissions. It was not feasible for this analysis to model the full array of technologies (many of which are bespoke), and we made some simplifying assumptions. With few exceptions, we did not include transformational technology changes. Our forecast is best viewed as the outcome of a reasonable pace of commercial and near-commercial technology deployment (existing technologies) and efficiency gains on oil sands GHG intensity. As a result, our outlook may be conservative, since some transformational changes will more than likely occur prior to 2030, including the deployment of a broader array of technologies than we considered that would result in a more dramatic reduction in GHG emission intensity.

The future intensity of CSS dilbit was not included in our outlook simply because of additional scope and because production remains relatively flat in the IHS Markit outlook to 2030.

Additional details are included in Appendix B.

## Uncertainty and comparability

Considerable data are required to estimate oil sands emissions by source. Alberta is unique in the quality of data available. However, some gaps still exist and some data may still be subject to improvements. For example, data for diesel fuel consumption were not universally available, and estimates of fugitive emissions appeared to be based on a limited sample.

Comparisons across various GHG intensity estimates are also challenging. Differences in key assumptions, such as emission conversion factors (the rate of carbon dioxide [$CO_2$] emitted per unit consumed or used) and system boundaries (such as whether and how indirect emissions associated with upstream or off-site production of energy use are included or not [IHS Markit included both]), can result in differences among estimates.

In this regard, Canada's NIR, prepared by Environment and Climate Change Canada, is often regarded as the gold standard for absolute Canadian and oil sands sector emissions. The NIR measures direct emissions. For comparison, the IHS Markit method adjusts for energy that crosses in and out of the facility or system boundary (see Figure 3).

8. When setting mining and SAGD baselines for facilities impacted by the Fort McMurray wildfire, we omitted data for 2016.

These differences do not mean that the IHS Markit results are inconsistent with the Government of Canada or that one is better than the other; IHS Markit and the NIR simply measure things differently. As a result, some variation in results should be expected. However, as shown in Table 1, adjusting the IHS Markit system boundary to align with the NIR (capturing only direct emissions and converting intensity estimates into total emissions) shows a high degree of correlation between IHS Markit and the NIR.

Table 1

**IHS Markit and Canada's NIR estimates of direct oil sands emissions** ($MMtCO_2e$)

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016** |
|---|---|---|---|---|---|---|---|
| **NIR** | | | | | | | |
| Mining and upgrading | 33 | 33 | 34 | 35 | 37 | 36 | 35 |
| In situ | 20 | 22 | 25 | 28 | 30 | 34 | 38 |
| **Total** | **53** | **55** | **59** | **63** | **67** | **70** | **73** |
| **IHS Markit** | | | | | | | |
| Mining and upgrading* | 35 | 32 | 35 | 36 | 36 | 36 | 29 |
| In situ | 21 | 22 | 26 | 29 | 32 | 36 | 39 |
| **Total** | **56** | **54** | **62** | **66** | **69** | **72** | **67** |
| **Difference** | **6%** | **-1%** | **5%** | **4%** | **2%** | **3%** | **-7%** |

*IHS Markit model does not allow differentiation between mining and mining upgrading emissions. China National Offshore Oil Corporation (CNOOC)/Nexen integrated in situ operations upgrading emissions are included in mining and upgrading until 2015, when the upgrader ceased operation. Their SAGD extraction emissions were included for in situ.
**In 2016, there was a large forest fire, and numerous operations were affected, which impacted emission estimates.
Source: IHS Markit, Environment and Climate Change Canada's NIR 2018 © 2018 IHS Markit

## The history of oil sands GHG emission intensity

This section presents the IHS Markit results of historical oil sands emissions, broken down by mining (mined SCO and mined dilbit [PFT]) and in situ (SAGD dilbit and CSS dilbit). Oil sands mining and thermal in situ (SAGD and CSS) accounted for more than 90% of all oil sands production in 2017 and account for nearly all of the oil sands growth in the IHS Markit outlook to 2030.[9]

### Sources of historical oil sands mining emissions, 2008–17

Nearly three-quarters of oil sands mining emissions result from the combustion of fossil fuels. These fuels include natural gas, process gas, and petroleum coke used in the generation of heat and electricity as well as diesel to power truck and shovel operations (the mobile mine fleet). Just over 5% of emissions stem from fugitives and flaring. Other emissions are indirect, resulting from some operations' import and use of electrical power and the diluent used in dilbit. Emissions are also associated with the upstream production of natural gas used to generate heat and power.

Note that each operation is unique. Some operations may have older vehicles, use shorter or longer mine trains (mine fleet needs to drive further), or use a different fuel mix for heat and power generation. For example, three of the six operating mines produce petroleum coke, only two combust it, and one facility operates a carbon capture unit. In recent years, two new mines have entered operation that use a PFT process that permits the marketing of dilbit as opposed to upgraded bitumen (SCO). This process negates the up-front cost and operating emissions associated with upgrading and results in a different emission profile (see Figures 4 and 5).

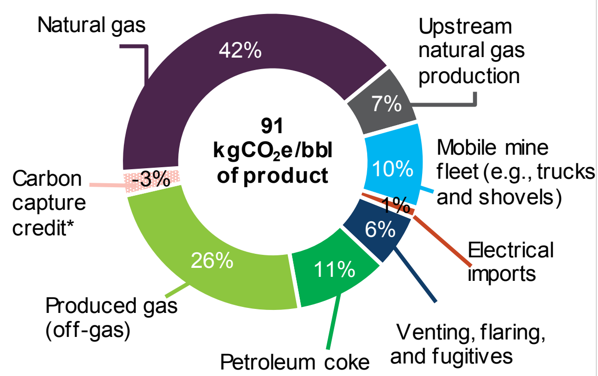
#### The evolution of oil sands mining (and emissions)

Oil sands mining has undergone several transformational changes over its 50-year history, which have influenced the industry's current emission profile. Some major changes included

9. Other forms of production include primary, experimental, and EOR techniques.

Figure 4

**Sources of oil sands mined SCO GHG emissions in 2017 (91 $kgCO_2e$/bbl of SCO)**

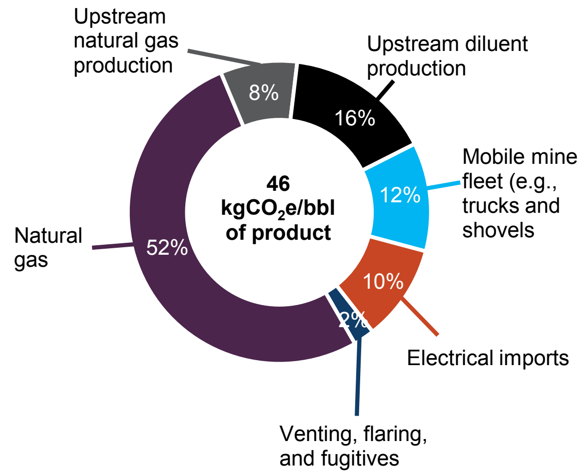



*In 2015, the Quest project commenced operations, capturing and sequestering $CO_2$ emissions from an oil sands upgrader. This results in a credit against SCO emissions using IHS Markit system boundary conditions. This credit is applied to natural gas for purposes of this figure.

Source: IHS Markit © 2018 IHS Markit

Figure 5

**Sources of oil sands mined dilbit (PFT) GHG emissions in 2017 (46 $kgCO_2e$/bbl of dilbit)**




Source: IHS Markit © 2018 IHS Markit

- **Bucket-wheel.** In the early 1990s, oil sands mining operations phased out bucket-wheel excavators in favor of trucks and shovels. The intention was to improve the efficiency of operations by transitioning from one critical point of failure—the bucket-wheel—toward the more redundant and flexible truck and shovel. Less downtime meant greater throughput on average and less energy and emissions per barrel produced.

- **Hydrotransport.** Also in the 1990s, warm water oil sands ore slurry pipe systems (known as hydrotransport) were introduced over legacy conveyor belt systems. Hydrotransport aids in the bitumen separation from the ore and has allowed operations to lower process temperature and thus energy and emissions per barrel.

- **PFT.** PFT removes impurities and precipitates out some of the heaviest parts of bitumen. This process eliminates the need for on-site upgrading and the associated emissions, with dilbit marketed instead of SCO. Note, however, that although the absence of upstream upgrading reduces the intensity of mined dilbit production, mined dilbit is more GHG intensive to refine than mined SCO.[10] As a result, the GHG intensity of the *upstream emissions*, including imported diluent, is roughly half that of the average mined SCO. However, on a well-to-tank basis (including upstream production and downstream refining up to the point of combustion), the GHG intensity of mined dilbit is about 25% lower than of mined SCO.[11] The first nonintegrated mine was completed in 2015 and the second in 2017.

### Oil sands mining emissions, 2008–17

Although mined SCO and mined dilbit (PFT) are both mining operations, they are distinct processes. For the most part, IHS Markit presents them both as part of the mining sector, but we also present them individually. What follows are the results of our historical mining estimates.

**Mining average.** The average intensity of oil sands mining operations fell 26%, or 29 $kgCO_2e$/bbl of marketed product (SCO and dilbit), over the past decade—from 112 $kgCO_2e$/bbl in 2008 to 83 $kgCO_2e$/bbl in 2017 (see

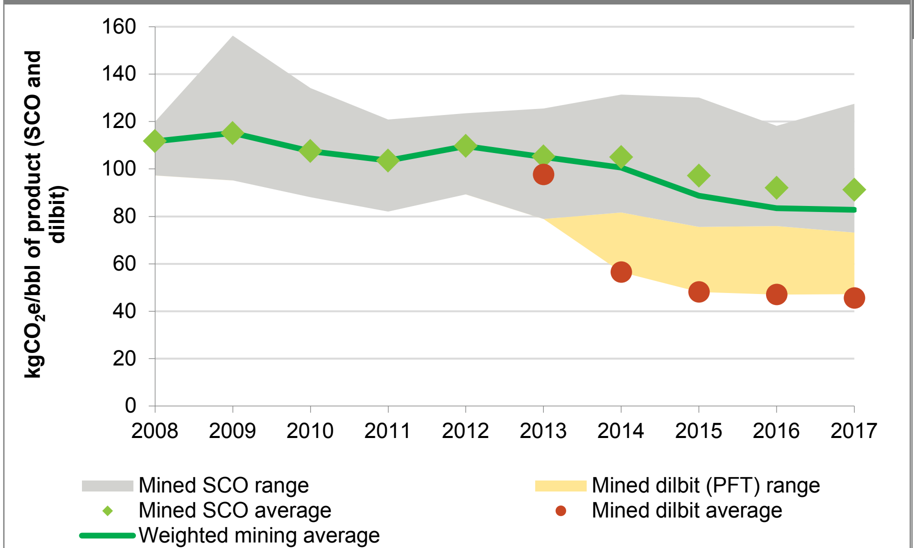
10. SCO is known as a bottomless crude because the heavy components have been converted to lighter molecules. Mined dilbit requires higher temperature and/or pressure than SCO to be converted into higher-value refined product.

11. Source: IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil.*

Figure 6). The main contributor was a reduction in the intensity of petroleum coke use, followed by the introduction of mined dilbit (diluting the overall mining emission average) and improvements and ramp-up of more efficient mined SCO operations (see Figure 7). Meanwhile, a reduction in the net trade of electricity offset some of the intensity reductions.

Figure 6

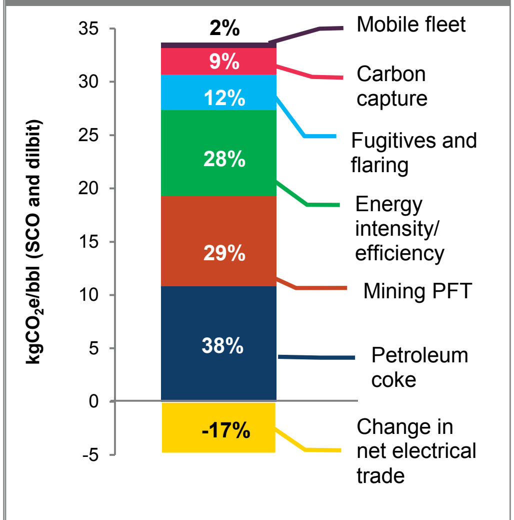
**Historical GHG intensity of mined oil sands by marketed product (SCO and dilbit)**




Source: IHS Markit © 2018 IHS Markit

Figure 7

**Source of oil sands mining GHG intensity improvement, 2008–17 (29 $kgCO_2e$/bbl of product)**




Source: IHS Markit © 2018 IHS Markit

In 2017, oil sands mining spanned from 46 $kgCO_2e$/bbl to 127 $kgCO_2e$/bbl of marketed product.

**Mined SCO.** Mined SCO emissions declined 18% over the same period (per barrel of SCO), to 91 $kgCO_2e$/bbl in 2017. The largest driver was the reduction in the intensity of petroleum coke use (which includes an increase of production not using petroleum coke). For more information on petroleum coke combustion, see the box "Petroleum coke: A by-product of mined SCO production."

## Petroleum coke: A by-product of mined SCO production

The combustion of petroleum coke has a similar GHG intensity as coal combustion—approximately two times more carbon intensive than natural gas.* Petroleum coke is a by-product of heavy oil processing in which high temperature and pressure are used to convert complex heavier molecules into lighter fractions. Although not all heavy oil processes generate petroleum coke, the most common process, known as thermal cracking or coking, does. Petroleum coke is not a unique result of oil sands crude but a common by-product of heavy crude oil processing globally.

In the oil sands, petroleum coke results from the upgrading process (upgraders are essentially freestanding heavy oil processing units). Petroleum coke is low value and was considered low-cost feedstock for heat and power in early oil sands mines. Three of the four mined SCO operations produce petroleum coke, and two combust it.

Over the past decade, petroleum coke use has declined as the price of natural gas has fallen and public interest in GHG emissions has increased. In 2008, approximately 1.76 million metric tons (MMt) of petroleum coke was

*See Table B-1 in Appendix B.

### Petroleum coke: A by-product of mined SCO production (continued)

combusted and/or exported from the oil sands—30% of the volume produced. In 2017, this amount had fallen to about 1 MMt and none was exported—this result was just over 10% of the volume produced.** Most of the petroleum coke produced in the oil sands is permanently stored.

Producers have made announcements that are expected to lead to further reductions in petroleum coke use. However, design limitations may also limit a total petroleum coke phaseout.***

**"ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement," AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st39, retrieved 4 April 2018.

***See Appendix B for additional details.

**Mined dilbit (PFT).** The first operation to market mined dilbit (PFT) began in 2013, followed by another operation in late 2017 (effectively 2018). As these new facilities have ramped up production (which is continuing), the GHG intensity of mined dilbit has fallen. In 2017, we estimate the GHG intensity of mined dilbit (PFT) production was 46 kg$CO_2$e/bbl.

## Sources of historical oil sands thermal emissions, 2009-17

Over the past decade, in situ, led by SAGD, has become the dominant source of oil sands production growth. SAGD accounted for two-fifths of oil sands production in 2017 and accounts for three-quarters of the oil sands growth in the IHS Markit outlook to 2030 (the remainder coming from the ramp-up and productivity improvements of mining operations, including debottlenecking projects). CSS was captured in our historical intensity estimates but was not a focus of the report because it is not expected to materially grow to 2030.

In situ operations are fundamentally different from mining because they rely on subsurface injection of steam (thermal energy) into the reservoir to mobilize and extract bitumen.

Nearly all on-site GHG emissions result from the combustion of natural gas for the generation of steam. Like mining operations, there are upstream emissions associated with the production of natural gas consumed on site and diluent imports. In 2017, SAGD operations exported more electrical power to the grid than they imported, which helped offset or lower their emission intensity (using our system boundaries) (see Figure 8).

No oil sands in situ operations currently operate an upgrader and thus produce or combust petroleum coke. In situ operations are generally more carbon intensive than mining without an upgrader (but not with an upgrader).

### The evolution of oil sands SAGD (and emissions)

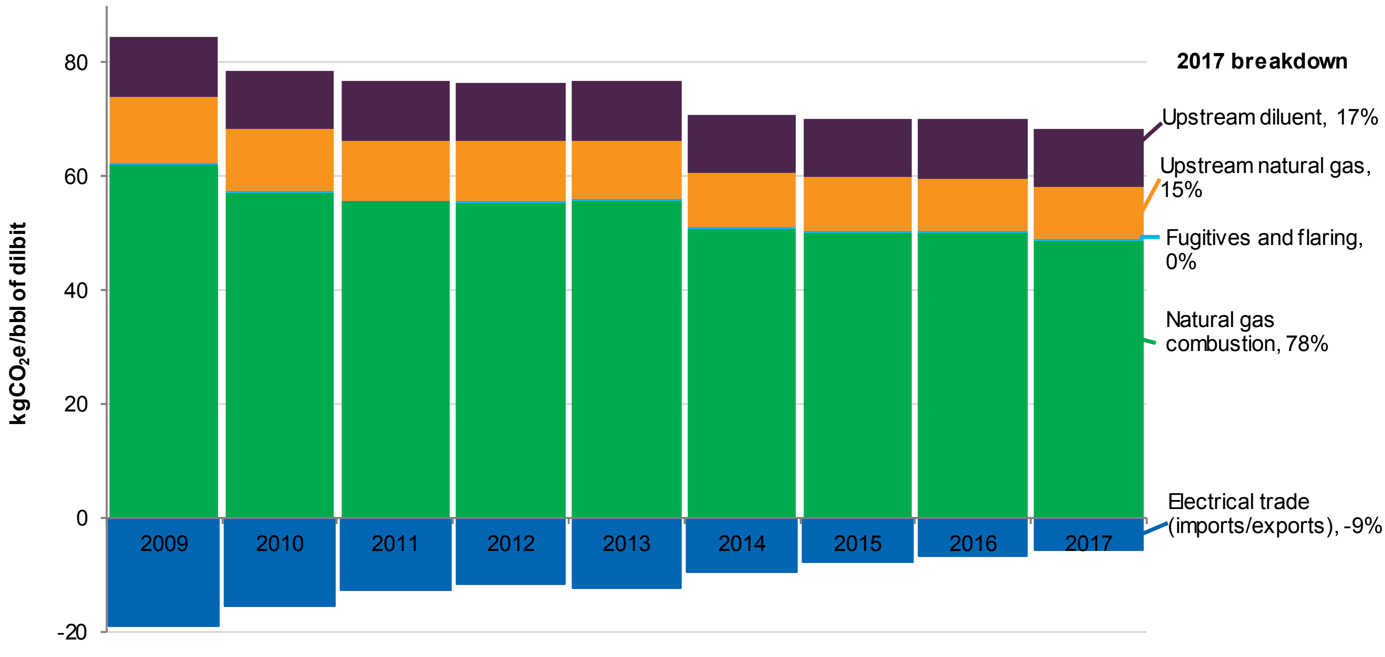
At about 17 years old, SAGD has yet to undergo any of the transformational changes that occurred in mining. Most emission intensity reductions have come from incremental improvements and learning by doing. Examples include greater accuracy in well placement, improvements in downhole monitoring, and better steam control (directing steam where it needs to go along the injection well and in the reservoir). More durable parts and predictive maintenance have helped reduce unplanned outages and downtime, improving reliability, utilization, cost, and emissions in the process.

The results have shown up in the industry average SOR, which declined 8% over 2009–17, from 2.95 to 2.71.

Figure 8

**Composition of historical SAGD dilbit GHG intensity, 2009–17**




Source: IHS Markit



Well productivity, which is measured by the daily volume of oil recovered per well, has also improved. From 2008 to 2015, the average productivity per SAGD recovery well in the oil sands increased more than 120%.[12]

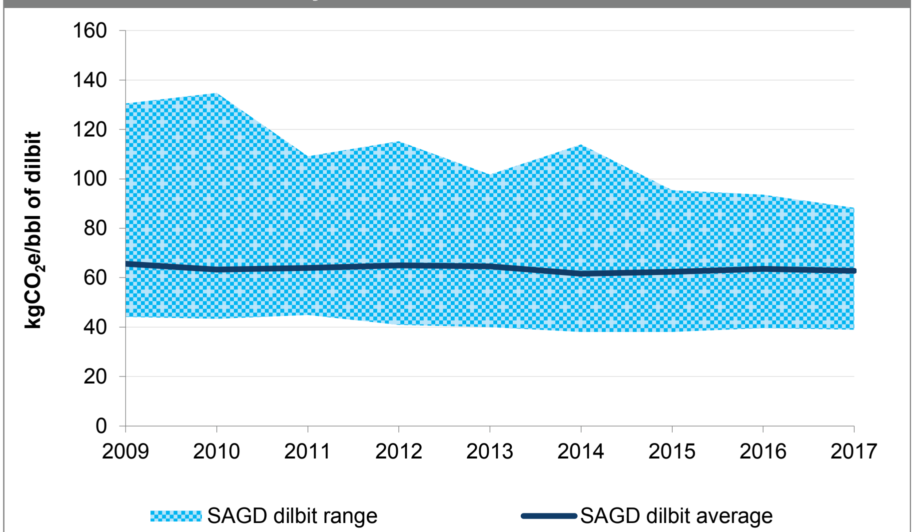
**Oil sands SAGD emissions, 2009–17**

Although operations have become more efficient (demonstrated by the falling SOR), the average emission intensity of SAGD dilbit has remained relatively constant—down 4% since 2009. Figure 9 shows the full range and average intensity of SAGD dilbit from 2009 to 2017. In 2017, the average intensity was estimated at 63 kg$CO_2$e/bbl of dilbit, while the industry ranged from 39 kg$CO_2$e/bbl to 88 kg$CO_2$e/bbl of dilbit.

This seemingly contradictory finding is a product of the IHS Markit system boundary conditions coupled with the industry's historical relationship with

Figure 9

**Historical GHG intensity of SAGD dilbit, 2009–17**




Source: IHS Markit



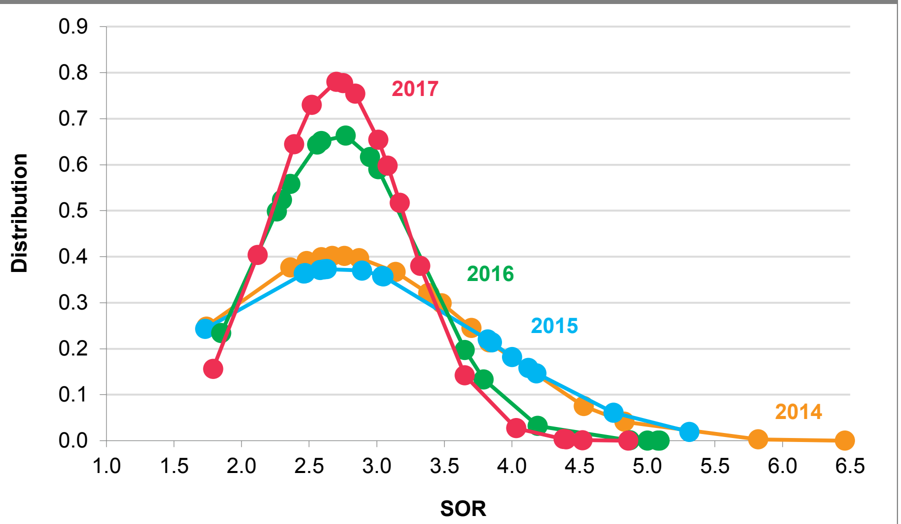
12. Source: AccuMapTM by IHS Markit.

cogeneration and electrical exports. Several facilities operate cogeneration units, which generate both steam and electricity. These operations can result in surplus electricity exported to the power grid. Although the use of cogeneration in SAGD is not ubiquitous, on average, the sector is a net energy exporter. Using the IHS Markit method (and life-cycle method), these emissions are deducted from the emission intensity. Over time, the ratio of cogeneration electrical generation capacity to production capacity has fallen as newer operations have more closely tailored cogeneration capacity to steam demand. Moreover, a reduction in investment since the price collapse arguably helped dampen the rate of cogeneration expansion, further tightening cogeneration capacity to production. This tightening has reduced electrical export intensity, all while operations have become more efficient, demanding less steam per barrel of oil (the SOR declined). Taken together, the reduction of electrical power export intensity has offset reductions in natural gas intensity, keeping overall emission intensity relatively flat. This relationship is visible in Figure 8, which shows that emissions from natural gas per barrel fell by about 13 kg$CO_2$e/bbl from 2009 to 2017 while the electrical export intensity credit declined by nearly the equivalent amount. This is an example of how system boundaries can impact results. For example, using direct emission system boundaries (shown in Figure 3), SAGD intensity fell 24% between 2009 and 2017.[13]

Meanwhile, the range of SAGD dilbit GHG intensity has tightened as outliers or more carbon-intensive operations have improved and facilities closer to the mean increased output. This result is visible in Figure 9 but more apparent in Figure 10, which plots the distribution of SOR of SAGD operations over the past four years (since the oil price collapse began).

Figure 10

Distribution of SAGD SOR by year




Source: AER, IHS Markit © 2018 IHS Markit

## An aside on CSS emissions, 2009–17

We included the history of CSS emission intensity, but not the outlook to 2030.

The use of CSS is limited to specific geological regions in the oil sands, and production is highly consolidated. In 2017, there were only three operating CSS projects, with 60% of output coming from one operation alone. In 2017, CSS accounted for 10% of total oil sands supply (inclusive of diluents).

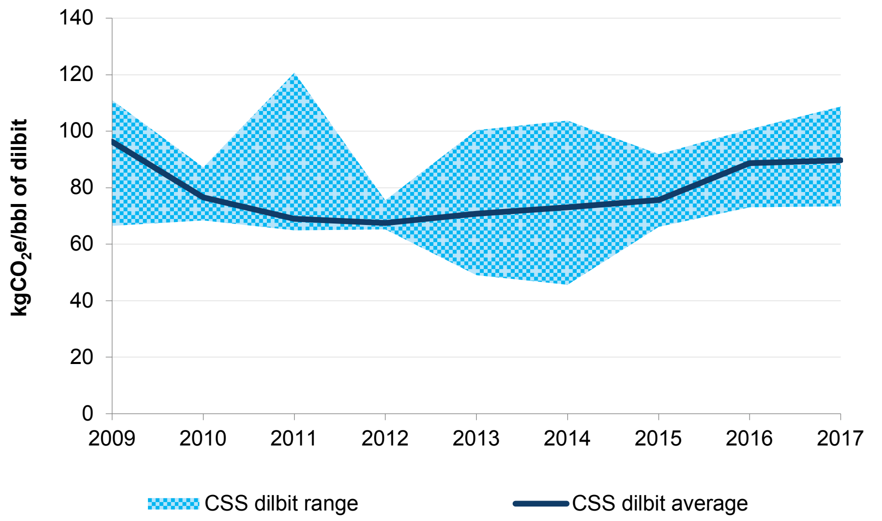
Although the emission intensity of CSS dilbit has been trending up in more recent years, the average intensity in 2017 (90 kg$CO_2$e/bbl of dilbit) was still 7% lower than in 2009 (see Figure 11). The overall reduction from 2009 to 2017 is linked to an increase in electrical exports to the grid, which has more than offset an increase in steam intensity (the SOR rose from 4.35 to 4.61 from 2009 to 2017). IHS Markit believes lower oil prices in recent years may have played a role in the increase, which could once again be influenced by higher oil prices.

13. Note that this differs from the summary table in Appendix A because this estimate is based on a bitumen barrel basis, which can be estimated using the same data.

## Mapping the future course of oil sands GHG emission intensity to 2030

Figure 11

**Historical GHG intensity of CSS dilbit, 2009–17**




Source: IHS Markit © 2018 IHS Markit

Looking to the future, questions abound about the trajectory of oil sands growth, the intensity of production, and, ultimately, absolute emissions. The promise of technology is often invoked as the reason emissions will fall. It is true that technology has the potential to lead to transformational changes in oil sands extraction and thus emissions. Yet, technology deployment can take time, it may never be applied universally, and, from a modeling perspective, a focus solely on new technology can overlook efficiency improvements and learning by doing—major drivers of historical emission improvements.

To be sure, this is a forecast, and modeling future oil sands is predicated on a wide range of assumptions—investment, production, and technology. Using a bottom-up approach, we sought to capture the impact of a reasonable pace of deployment of commercial and near-commercial technologies and potential efficiency improvements on the GHG intensity of production. With few exceptions, transformational technologies were not modeled. As a result, we view our outlook as conservative, or a projection of current trends.

We discuss the potential technologies and improvements first. This discussion is followed by the results and projections for future emissions. IHS Markit results are presented as a range to capture some of the uncertainty regarding the pace of deployment and potential benefits. For simplicity, the upper-bound contains more conservative assumptions, whereas the lower-bound considers a more aggressive deployment of current technology and know-how. In both cases, IHS Markit used the same production outlook and project composition to 2030.

### The question of reservoir quality

In addition to the advancement of new extractive technologies and further efficiency improvements, IHS Markit considered two additional factors influencing the future trajectory of oil sands emissions: reservoir or resource quality and production growth.

- **Production growth influences both absolute and industry emission intensity.** The greater the level of growth, the higher absolute emissions are likely to be, but likely at lower intensity. This is because newer projects tend to benefit more from the latest technology. The greater the share of new production, the greater the impact on the average industry performance. An example of this dilution effect is clearly visible from the impact of the introduction of mined dilbit (PFT) on mining emissions. This example also highlights how composition—which projects advance—influences average emission intensity.

IHS Markit expects growth in the Canadian oil sands to continue to 2030, but at a slower pace.[14] By 2030, production (SCO and bitumen) could approach 4 MMb/d, roughly one-quarter million barrels lower than our pre–oil price collapse forecast from 2014. The composition of projects in the IHS Markit outlook has also tilted toward SAGD projects because they are lower cost and quicker to first oil. This change implies that the future of mining emissions may rely more on existing facilities, whereas the future of SAGD emissions has the added complexity of being influenced by the projects that could advance in the future.

- **Oil sands reservoir quality is not yet expected to materially limit GHG emission improvements to 2030.** Within any reservoir or play, the geology will vary, influencing the quality and ease of extraction. Terms such as "sweet spots" have been given much visibility by the rise of US tight oil. However, the varying quality holds true in most reservoirs. Reservoir quality can influence the type of oil sands operations differently. For mines, it can influence the degree of ore handling. For in situ operations, steam intensity can be affected. Both can influence the GHG intensity of extraction.

  Over the coming decade, based on the current IHS Markit understanding and production outlook, while some outliers may occur, on average, we do not expect our results to be materially impacted by the quality of oil sands reservoirs under active development. There were a couple reasons for this:

  In the case of the oil sands, there is a lot of oil still out there. Of the estimated 177 billion bbl of recoverable resources, only 7.5% has been exploited to date.[15] Certainly, the quality of the reservoirs varies, and there is nothing to prevent anyone from building in a more challenging area. However, many attractive areas remain. Lower prices have also slowed the pace of future growth, slowing the rate at which industry will move through the resource. Meanwhile, Alberta and Canada's planned escalation of carbon pricing and industry consolidation will likely discourage investments in lesser-known regions and drive capital preferentially toward areas that are better understood, with more attractive reservoirs.

  For our study, estimates of the performance of new projects were informed by regulatory submissions, which provide guidance on the expected operating profile for the majority of our outlook period. For existing projects, as they move through their leases, future performance could be impacted late in our outlook period. However, we believe that the use of conservative technology assumptions, particularly in the upper-bound case, provide a further hedge against the possible impact should some projects gradually move into lower-quality reservoirs.

## A possible future of oil sands mining emissions to 2030

IHS Markit expects oil sands mining production growth to be outpaced by SAGD extraction following the ramp-up of recently completed mining operations and recently sanctioned debottlenecking projects.[16] Any meaningful change in emission intensity may be more reliant on existing operations. Barring a transformational change in extraction technology (as per IHS Markit study assumptions, these were not included), there may be a limited set of levers currently available to oil sands mining operations to lower emissions. These levers are also not evenly distributed across operations. For example, in 2017, petroleum coke combustion, which occurred at only two mining operations, still accounted for about 9% of the emission intensity of oil sands mining (mined SCO and mined dilbit combined).

14. For more information, see "Uncertainties continue to weigh on the oil sands growth story," IHS Markit, https://ihsmarkit.com/research-analysis/uncertainties-continue-to-weigh-on-the-oil-sands-growth-story.html.

15. "ST98: Alberta's Energy Reserves and Supply/Demand Outlook," Table R3.2: Reserve and production change highlights (106 m3), AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98, retrieved 30 May 2018.

16. In 2017, both the Fort Hills mined dilbit (PFT) and the Horizon mined SCO expansions commenced operations, while the Kearl mined dilbit (PFT) facility announced it would be undertaking a debottlenecking project during 2018 and 2019. Horizon has also announced additional work it could undertake to expand output.

IHS Markit identified five key areas where commercial or near-commercial technology or efficiency improvements could drive GHG emission intensity improvements. These included fuel switching from petroleum coke to gas; cogeneration capacity expansion; fuel switching and efficiency gains in the mobile mining fleets; separation process improvements, such as a reduction in process temperature; and carbon capture and storage (CCS). Further background on each potential improvement area is discussed in the box "Oil sands mining assumptions," with detail on what was modeled included in Table 2.

## Oil sands mining assumptions

**Fuel switching.** Two mining operations currently combust petroleum coke: Suncor base mine and Syncrude. The Suncor plant uses specially designed boilers to combust petroleum coke, while at Syncrude combustion occurs as part of the plant's upgrading process. There may be opportunities to convert existing coke-fired boilers to natural gas or introduce cogeneration capacity, which could reduce coke combustion. In fact, Suncor Energy has announced the phaseout of coke boilers on its site, in favor of two new cogeneration units.* However, because Syncrude combusts petroleum coke as part of its upgrading process, options may be more limited without a more involved redesign.

**Cogeneration.** For the most part, oil sands mining operations are electrically balanced—neither major importers nor exporters of electricity from the grid. To meet demand, they use a combination of boilers and cogeneration units. An expansion of mining cogeneration capacity could alter the industry energy balance and energy export intensity.

**Mobile mining fleet.** Oil sands mining operations have large fleets of heavy equipment haulers, shovels, and earthen works equipment, which run on diesel. These fleets can be extensive; for example, one mine has well over 150 trucks and shovels of various sizes (all of the vehicles are not in operation at any given time, but this number gives a sense of scale). LNG for heavy equipment is a proven technology and has been tested in the field. Autonomous mining vehicles are not more combustion efficient but can reduce vehicle downtime and improve utilization—reducing emission intensity. One operator has announced its intention to phase in autonomous vehicles at scale.** Both technologies can lower emission intensity but will also take time to deploy and turn over the existing fleet.

**CCS.** CCS involves the capture and geological storage of $CO_2$ emissions from the combustion of fossil fuels. Currently, there is one oil sands mine with an integrated capture unit.*** Although IHS Markit considered further deployment of CCS, this was not modeled in our outlook because the core oil sands mining region is remote from likely geological storage options. The only operating facility is unique in that the installed capture facility is integrated into an upgrader located in Edmonton, Alberta—far from oil sands operations. Since 2009, $CO_2$ has also been injected into tailing material at the Horizon mined SCO project. Although some $CO_2$ is most likely being sequestered, there was uncertainty to the degree or volumes, and they were not included in our estimate.****

*"Coke Boiler Replacement Project," Suncor, http://www.suncor.com/about-us/oil-sands/process/coke-boiler-replacement-project, retrieved 2 February 2018.

**"Suncor Energy Implements First Commercial Fleet of Autonomous Haul Trucks in the Oil Sands," Suncor, 30 January 2018, http://www.suncor.com/newsroom/news-releases/2173961, retrieved 30 May 2018.

***For more information on the Shell Quest CCS project, see "Quest Carbon Capture and Storage," Shell, https://www.shell.ca/en_ca/about-us/projects-and-sites/quest-carbon-capture-and-storage-project.html, retrieved 18 July 2018.

****For more information, see "Managing Tailings," Canadian Natural Resources, https://www.cnrl.com/corporate-responsibility/advancements-in-technology/managing-tailings.html, retrieved 30 July 2018.

## Oil sands mining assumptions (continued)

**Process efficiency.** The separation of bitumen from sand, clay, and water in mining operations requires large volumes of warm water. This requires energy. Over time, as operations have become more efficient, this temperature has generally fallen and/or greater waste heat integration has reduced energy demand to maintain process temperature. Further efficiency gains are likely to drive greater efficiency and thus emission improvements. The application of solvents in the mining separation process is under development, which could dramatically improve process temperature or allow greater output from existing heat use.

Table 2

**IHS Markit GHG intensity mining outlook assumptions**

| Pathway | Description | Upper-bound case (more conservative) | Lower-bound case (more aggressive) |
|---|---|---|---|
| Fuel switching | Two mining operations combust petroleum coke. There are economic and technical limitations to fuel switching. In 2017, petroleum coke combustion accounted for 9% of the intensity of oil sands mining, or about 8 $kgCO_2e/bbl$ of product. | At one of the two mines combusting petroleum coke, Suncor, we assumed that the existing coke boilers would be phased out in 2022. Both units were assumed to be replaced with cogeneration units, which ties this assumption to the cogeneration assumption. IHS Markit estimates that this would half industry petroleum coke use/ combustion. | |
| Cogeneration expansion | Building cogeneration facilities can reduce the net GHG emission intensity of oil sands facilities owing to simultaneous production of steam and electricity. | IHS Markit modeled the addition of two 350 MW additions to the Suncor base mine in 2022 as announced by Suncor Energy. | In addition to the upper-bound case assumptions, three additional 100 MW units were phased in at a rate of one per year between 2023 and 2025. The dates chosen were arbitrary, but facilities were chosen to make current net electrical importers and net exporters to the grid (or more accurately, roughly balance them). |
| Mobile mine fleet operations | The mobile mine fleet accounts for about 11% of emissions today. Advancements in engine technology, deployment of commercial LNG engines, and greater fleet optimization through autonomous vehicles could drive improvements. | The introduction of LNG engines was modeled starting in 2021 at 1% of the fleet, increasing to 5% by 2025. Adoption of an autonomous mine fleet was assumed at one operation beginning in 2019 with a 1% improvement in efficiency, ramping up to a maximum of 10%; then adoption was assumed to expand to all other mines in 2024, ramping up at 1% per year and reaching a maximum of 7% in 2030. | The introduction of LNG engines was modeled starting in 2021 at 1% of the fleet, increasing to 10% of the fleet by 2030. The adoption of an autonomous mobile mine fleet was assumed to begin at one operation in 2019, resulting in a 2% improvement per year in fleet intensity to a maximum of 14%. Autonomous trucks were assumed to expand to all other mines beginning in 2022 at an accelerated rate of 2% per year to a maximum fleet penetration of 14%. |
| Efficiency improvements (e.g., process temperature/waste heat integration) | Oil sands mines are large consumers of heat to extract bitumen and produce SCO. There is room for improvement through methods such as heat integration, optimization, and use of solvents. | To capture improvements or reductions in process energy demand, IHS Markit modeled the equivalent to a 0.5 degree Celsius (°C) reduction per year in process temperature, starting in 2020 for legacy mining operations producers and 2024 for newer facilities at half the rate (0.25°C) per year because newer facilities were assumed to operate at cooler rates. By 2030, older operations reach an equivalent reduction of 5.5°C, while newer operations get to 3.5°C.* | The equivalent of a 0.5°C per year reduction in process temperature was modeled starting in 2018 for legacy mining operations and 2020 for newer facilities.* Solvent-aided separation technology was included, being adopted starting in 2026 for mined SCO operations and 2028 for mined dilbit (PFT) facilities, resulting in an immediate 5°C temperature reduction, increasing by 0.5°C per year (resulting in a 1°C temperature improvement per year thereafter). By 2030, older operations reach an equivalent reduction of 11.5°C, while newer operations get to 10.5°C.* |
| CCS | CCS has the potential to sequester $CO_2$ emissions directly at the source. | An absence of quality disposable sites in core oil sands regions results in limited sequester opportunities currently, and we did not model beyond what is already established. | |

*Legacy operations include Suncor base mine, Syncrude, and Albian Sands.

Source: IHS Markit

IHS Markit expects that more transformational technologies will come forward, which will lead to far more radical emission reductions than considered in this study. Indeed, industry and governments are investing in new technologies, and many are in advanced pilots. An exhaustive list of these technologies and their state of commerciality would easily necessitate its own report. Moreover, the subsequent modeling effort would be even more complex. Instead, we sought to understand the trajectory of the GHG emission intensity of oil sands extraction as a result of ongoing efficiency improvements and a reasonable pace of deployment of commercial and near-commercial technologies today. For these reasons, we view our output as conservative. However, equally true is the role that a more optimistic oil price or investment outlook could play in influencing future emissions.

## Results: Carbon intensity of future mining operations

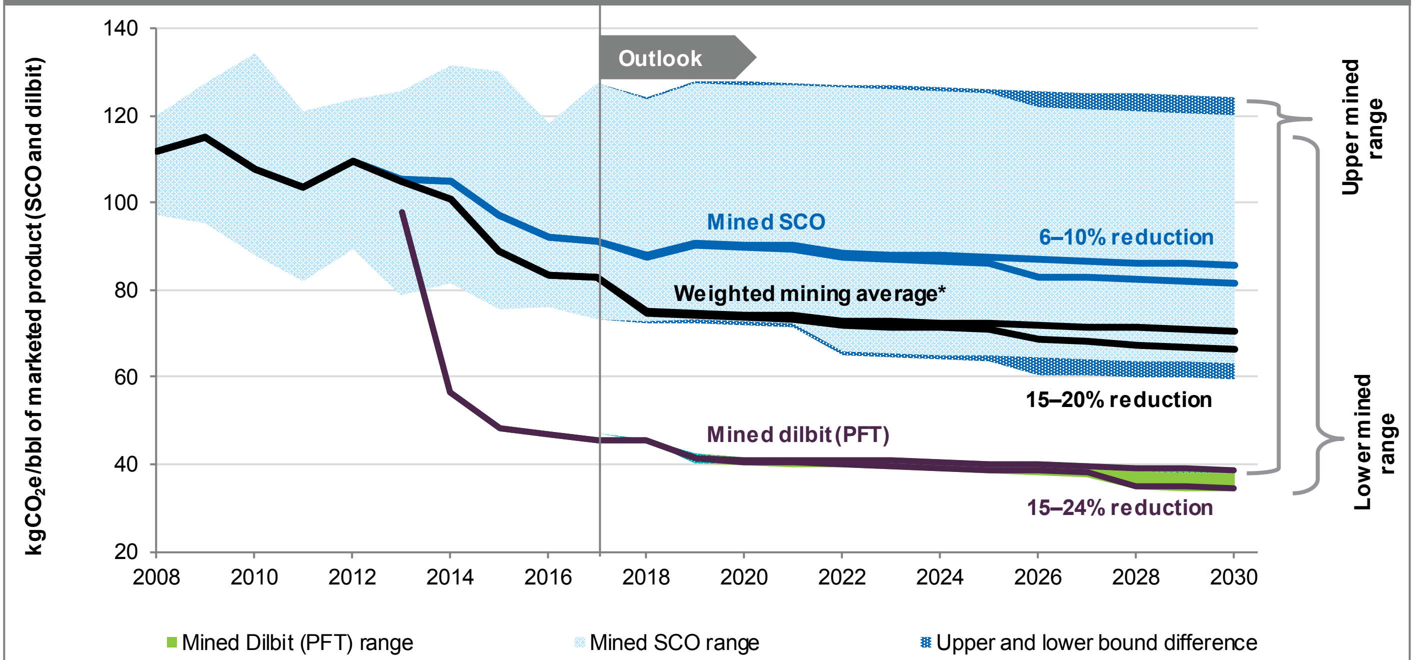
Like historical oil sands mining emissions, results are presented as a mining average, as well as separately for mined SCO and mined dilbit (PFT).

**Mining average.** The average GHG intensity of upstream oil sands mining on a marketed product basis (SCO and dilbit) falls by 12–16 kg$CO_2$e/bbl from 2017 to 2030 in the IHS Markit outlook—a 15–20% reduction (see Figure 12). Average mined oil sands production emissions in 2030 range from 67–71 kg$CO_2$e/bbl. This is less than the historical drop of 2–3% per year during 2008–17. Figures 13 and 14 break down the key contributors behind the reduction in our outlook to 2030. Many of the key drivers, such as the ramp-up of newer mined dilbit (PFT) processes—diluting more GHG-intensive legacy integrated mined SCO operations—and a reduction in petroleum coke use, are arguably already under way.

**Mined SCO.** The GHG intensity of mined SCO falls by 6–10 kg$CO_2$e/bbl from 2017 to 2030—a reduction of 6–10%. Average mined SCO production emissions range from 82–86 kg$CO_2$e/bbl in 2030. Improvements in process temperature/efficiency are the largest contributor, followed by reductions in the use of petroleum coke.

Figure 12

GHG intensity of oil sands mining by marketed product (SCO and dilbit), 2008–30

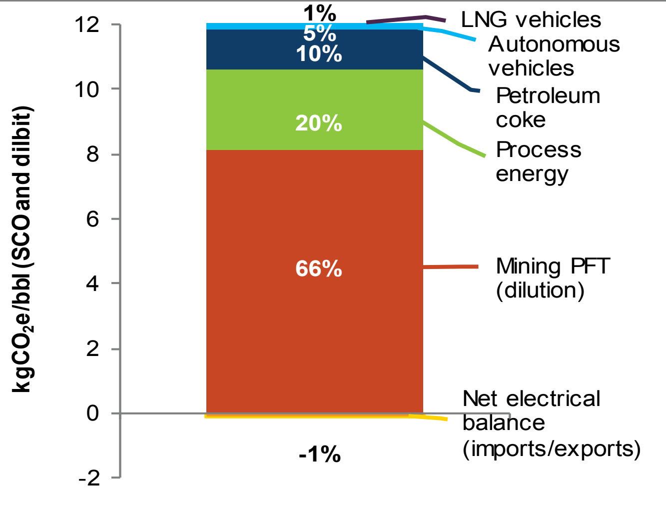



*Estimate of total oil sands average includes mined SCO and mined dilbit.
Source: IHS Markit

© 2018 IHS Markit

Figure 13

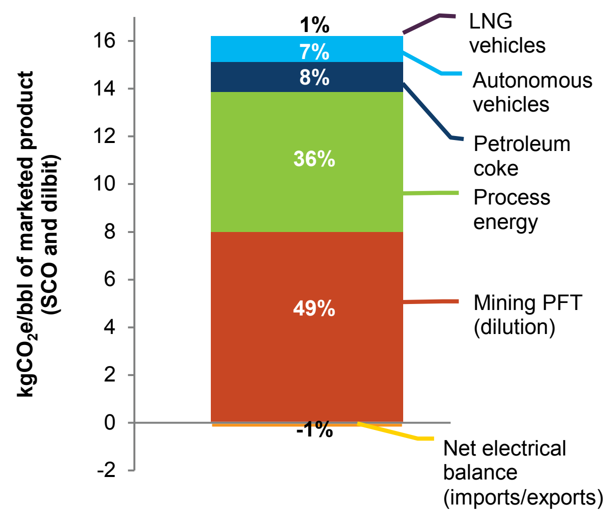
Source of oil sands mining GHG intensity improvement, 2017–30 (12 $kgCO_2e$/bbl of product)




Source: IHS Markit © 2018 IHS Markit

Figure 14

Source of oil sands mining GHG intensity improvement, 2017–30 (16 $kgCO_2e$/bbl of product)




Source: IHS Markit © 2018 IHS Markit

**Mined dilbit (PFT).** Mined dilbit (PFT) emissions continue to fall as facilities ramp up production, complete debottlenecking work, and normalize operations. Improvements in process temperature/efficiency help lower emission intensity over time. Mined dilbit (PFT) emissions decline by 7–11 $kgCO_2e$/bbl—a 15–24% reduction—bringing emissions in 2030 to 34–39 $kgCO_2e$/bbl.

For more details, see the box "Oil sands mined SCO and mined dilbit (PFT) cases in detail." Detailed results can be found in Appendix A.

## A possible future of oil sands SAGD emissions to 2030

SAGD has become the dominant source of oil sands growth. Between 2017 and 2030, roughly half of the anticipated 1.2 MMb/d rise in the IHS Markit oil sands outlook is expected to come from new SAGD projects, which include entirely new greenfield operations and expansions of existing facilities. As a result, what happens to SAGD will weigh not only on production but also on GHG emission intensity.

IHS Markit explored four key areas as having the potential to drive emission improvements in SAGD operations. These included well productivity, boiler/steam generation efficiency, steam displacement technologies (such as solvents), and cogeneration. The type and volume of future or yet-to-be-sanctioned SAGD projects also influence future emission intensity. Similar to mines, transformational technologies were not included.[17]

Detailed improvements are outlined in Table 3 following the box "Oil sands mined SCO and mined dilbit (PFT) cases in detail", with additional background in the box "Oil sands SAGD assumptions."

17. It is an arguable point whether steam displacement technologies are transformational. They were included since we deemed them to be commercial or near commercial.

## Oil sands mined SCO and mined dilbit (PFT) cases in detail

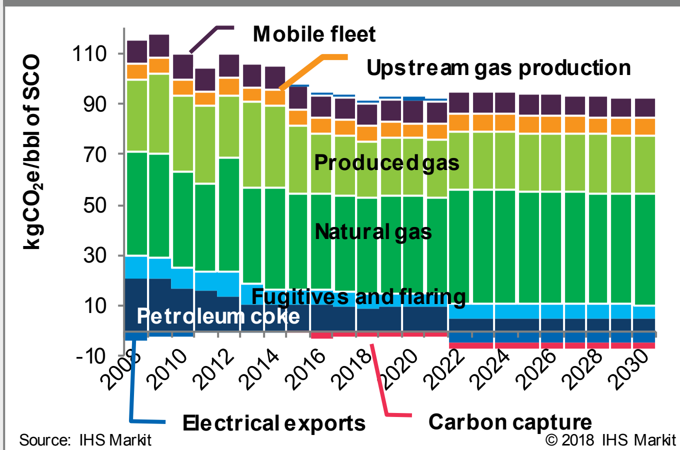
IHS Markit explored four key levers—and two sets of assumptions affecting the intensity of these levers—impacting the future carbon intensity of mining operations. This text box presents the results of the individual cases by mined SCO and mined dilbit (PFT) for the two cases or sets of assumptions modeled.

### Oil sands mined SCO

In the IHS Markit upper-bound (more conservative) case, oil sands mined SCO emissions decline from 91 $kgCO_2e/bbl$ in 2017 to 86 $kgCO_2e/bbl$ in 2030—a 6% reduction. The introduction of 700 MW of cogeneration in conjunction with a reduction in petroluem coke combustion is noticeable in the mined SCO emission profile in 2022 in Figure 15 as the rise in associated natural gas combustion emissions is more than offset by the combined reductions from less petroleum coke use and greater electrical export intensity. Figure 16 shows the drivers of the roughly 6 $kgCO_2e/bbl$ decline from 2017 to 2030. The major contributors are process temperature and efficiency and a reduction in petroleum coke intensity (which includes not only reductions in use but also an increase in output from facilities not using petroleum coke). The ramp-up of newer lower-emission mined SCO operations and the deployment of autonomous vehicles also contribute.

Figure 15

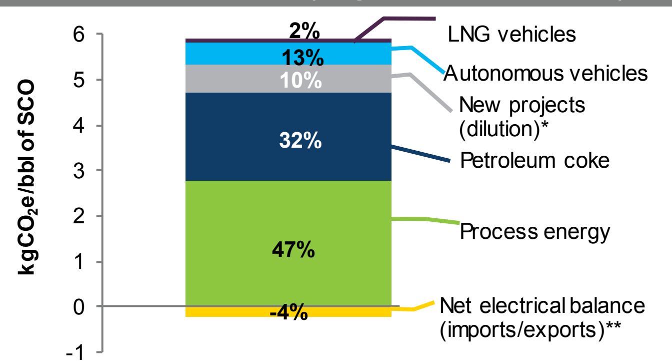
**Composition of upper-bound mined SCO intensity, 2008–30**




Source: IHS Markit © 2018 IHS Markit

Figure 16

**Source of upper-bound mined SCO GHG intensity improvement, 2017–30 (6 $kgCO_2e/bbl$ of product)**




*New projects represent changes in intensity due to ramp-up of operation and performance of legacy operations. **Inclusive of increase in natural gas demand to meet cogeneration less heat from cogeneration and surplus power export to the grid.

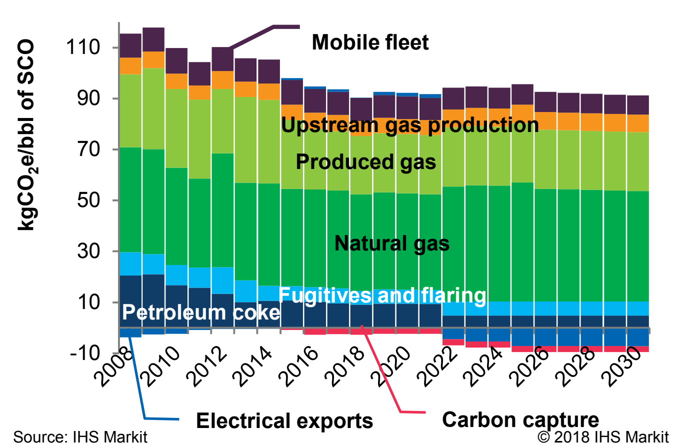
Source: IHS Markit © 2018 IHS Markit

In the IHS Markit lower-bound (more aggressive) case, oil sands mined SCO emissions decline from 91 $kgCO_2e/bbl$ in 2017 to 82 $kgCO_2e/bbl$ in 2030—a 10% reduction. A petroleum coke reduction and project performance have a fixed or equivalent impact on both the upper- and lower-bound cases and thus account for a smaller percentage of the greater reduction in the lower-bound case. Stronger process temperature improvements make larger contributions to intensity improvements (see Figures 17 and 18).

## Oil sands mined SCO and mined dilbit (PFT) cases in detail (continued)

Figure 17

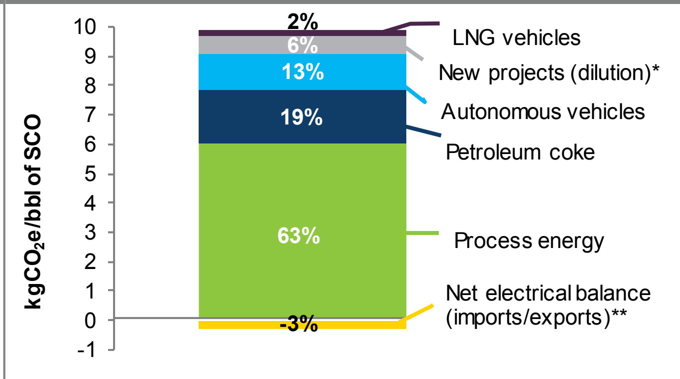
**Composition of lower-bound mined SCO intensity, 2008–30**




Source: IHS Markit © 2018 IHS Markit

Figure 18

**Source of lower-bound mined SCO GHG intensity improvement, 2017–30 (10 $kgCO_2e$/bbl of product)**




*New projects represent changes in intensity due to ramp-up of operation and performance of legacy operations. **Inclusive of increase in natural gas demand to meet cogeneration less heat from cogeneration and surplus power export to the grid.

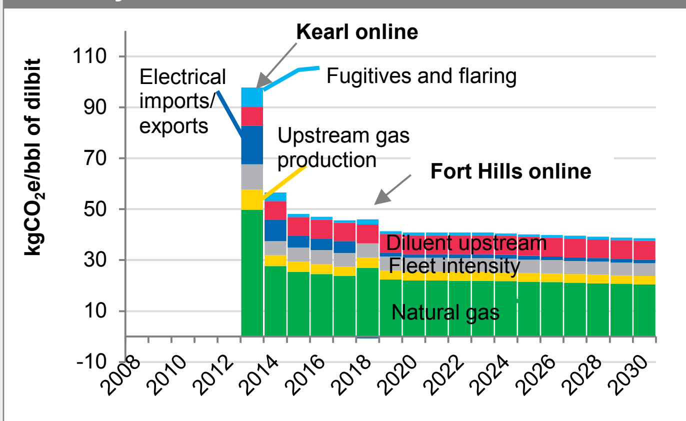
Source: IHS Markit © 2018 IHS Markit

### Oil sands mined dilbit (PFT)

In the IHS Markit upper-bound (more conservative) case, oil sands mined dilbit (PFT) emissions decline from 46 $kgCO_2e$/bbl in 2017 to 39 $kgCO_2e$/bbl in 2030—a 15% reduction. Project performance is by far the largest contributor, driven by improvements in reliability at the two mined dilbit (PFT) operations: the ramp-up of the Fort Hills project during 2018 and the undertaking of a debottlenecking project at the Kearl facility into 2019 will improve plant reliability and lower emission intensity as a result. To a lesser extent, process temperature and the rollout of an autonomous fleet also contribute (see Figures 19 and 20).

Figure 19

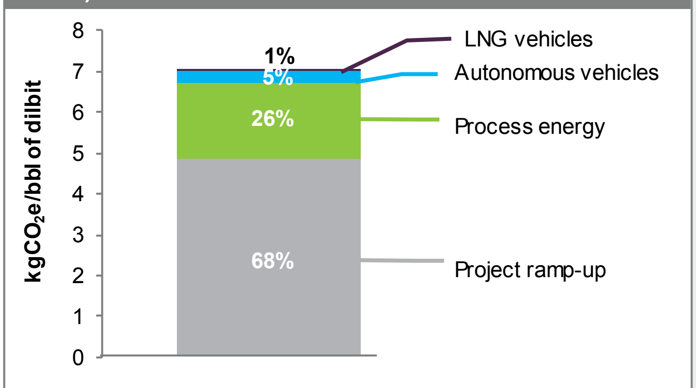
**Composition of upper-bound mined dilbit (PFT) intensity, 2008–30**




Source: IHS Markit © 2018 IHS Markit

Figure 20

**Source of upper-bound mined dilbit (PFT) GHG intensity improvement, 2017–30 (7 $kgCO_2e$/bbl of dilbit)**




Source: IHS Markit © 2018 IHS Markit

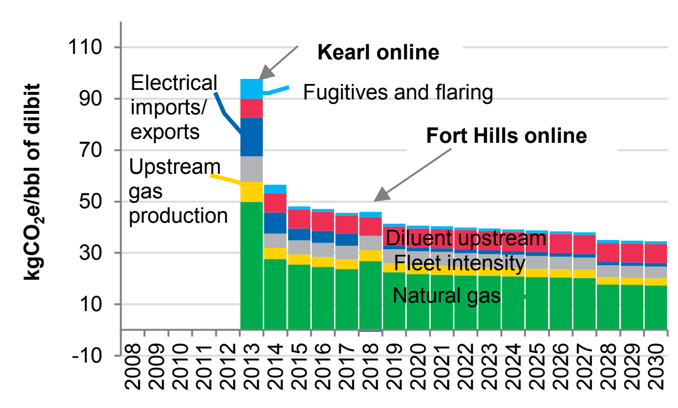
 

## Oil sands mined SCO and mined dilbit (PFT) cases in detail (continued)

In the IHS Markit lower-bound (more aggressive) case, oil sands mined dilbit (PFT) emissions decline from 46 $kgCO_2e$/bbl in 2017 to 34 $kgCO_2e$/bbl in 2030—a 24% reduction. The process temperature edges out project ramp-ups, with the lockstep change in process temperature modeled clearly visible in 2028. Improvements in the reliability of the two mined dilbit (PFT) operations contribute to the same absolute improvement but are a smaller share of the total reduction (see Figures 21 and 22).

Figure 21

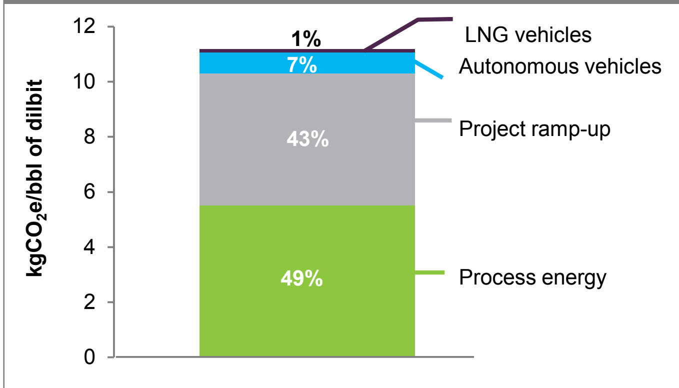
**Composition of lower-bound mined dilbit (PFT) intensity, 2008–30**




Source: IHS Markit © 2018 IHS Markit

Figure 22

**Source of lower-bound mined dilbit (PFT) GHG intensity improvement, 2017–30 (11 $kgCO_2e$/bbl of dilbit)**




Source: IHS Markit © 2018 IHS Markit

Detailed data tables can be found in Appendix A.

Table 3

**IHS Markit GHG intensity SAGD outlook assumptions**

| Pathway | Description | Upper-bound case (more conservative) | Lower-bound case (more aggressive) |
|---|---|---|---|
| Well productivity | More durable submersible pumps, advanced seismic, greater drilling precision, and infill wells can increase the volume of oil produced with little increase in heat/steam/energy required. Over the past decade, well productivity for oil sands thermal projects has improved about 10% per year on average; however, this does not directly correlate to emission intensity improvement. | A 1% annual improvement was modeled starting in 2018. New wells were credited with the cumulative improvement the year the well is completed, with that benefit fixed (no additional gain) for the life of that well. For a well drilled in 2030, the cumulative productivity gain would reach 12%, but because the benefit was limited to new wells and fixed for the life of the well, the weighted average impact across the industry is just over 5%. | A 2% annual improvement was modeled starting in 2018. New wells were credited with the cumulative improvement the year the well is completed, with that benefit fixed (no additional gain) for the life of that well. For a well drilled in 2030, the cumulative productivity gain would reach 24%, but because the benefit was limited to new wells and fixed for the life of the well, the weighted average impact across the industry is nearly 11%. |
| Boiler/steam generation efficiency | The quality of water affects the efficiency of steam production. Lower water quality means less steam is produced for a similar level of fuel consumption. Improvements in water treatment and boiler technology can improve the transfer of natural gas combustion to steam production and reduce the energy intensity of steam generation. | A 1% annual improvement in boiler/ steam efficiency was modeled between 2021 and 2024. Improvements were stepped down in 2025 to 0.25% per year to reflect the likelihood that further improvements would require new technology. By 2030, the total efficiency gain is 5.5%. | A 2% annual improvement in boiler/ steam efficiency was modeled between 2019 and 2023 as new technologies and better water treatment capabilities. Improvements were stepped down in 2024 to 0.5% per year to reflect the likelihood that further improvements would require new technology. By 2030, the total benefit reaches 8.5%. |

Table 3

**IHS Markit GHG intensity SAGD outlook assumptions (continued)**

| Pathway | Description | Upper-bound case (more conservative) | Lower-bound case (more aggressive) |
|---|---|---|---|
| Steam displacement technologies | Steam displacement technologies, including natural gas coinjection and solvents, are increasingly being piloted in the field. These technologies physically reduce the volume of steam required to produce a barrel of oil. Solvents have the added benefit of increasing the mobility of bitumen and increasing the well productivity as a result. Often, solvents may also lead to the recovery of a slightly higher-quality oil. | Associated with coinjection technologies, beginning in 2020, a 4% improvement in the SOR was modeled, increasing at a rate of 0.5% per year. A further 2% improvement in the SOR was modeled associated with the deployment of solvent technology beginning in 2024 for new wells and wells drilled in the prior three years (back to 2021) with the benefit escalating at 0.5% per year (1% in combination with displacement technologies). The net gain was estimated improvement of 14% by 2030. Similar to well productivity, the benefit of these technologies was restricted to new wells but, unlike well productivity, allowed to escalate. The weighted impact exceeds 9% in 2030. | IHS Markit assumed much faster learning curves. Associated with coinjection technologies, beginning in 2019, a 4% improvement in the SOR was modeled, increasing at 0.5% per year until 2022. A further 3% improvement in the SOR was modeled associated with the deployment of solvent technology beginning in 2022 for new wells and wells drilled in the prior three years (back to 2020) with the benefit escalating at 0.5% per year until a maximum of 6% improvement is attained in 2028. The net gain for affected wells was a steam intensity reduction of 20% by 2030. However, because benefits were restricted to new wells, the weighted average impact is just over 13% in 2030. |
| Cogeneration expansion and net electrical balance | Building cogeneration facilities can reduce net GHG emission intensity of oil sands facilities owing to simultaneous production of steam and electricity and subsequent export of electricity. SAGD facilities are currently net exporters of electricity owing to their higher steam demand compared with electricity use. | In addition to existing installation cogeneration capacity, IHS Markit assumed that a cogeneration unit (85 MW) could be deployed as facilities achieve 60,000 b/d thresholds between 2020 and 2030. | In addition to existing installation cogeneration capacity, IHS Markit assumed that a cogeneration unit (85 MW) could be deployed as facilities achieve 45,000 b/d thresholds between 2020 and 2030. |

Source: IHS Markit



## The importance of deployment

Across the board, technology improvement assumptions may not work for estimating future oil sands GHG emission intensities. Thermal in situ extraction processes use wells to access subsurface oil sands deposits. These wells have limited lifespans. As areas of the reservoir under active production deplete, new wells, known as sustaining wells, must be drilled and brought online to replace the declining productivity of mature wells. This changeover of wells can impact the deployment of new technologies that rely on the life or placement of new wells. For example, steam displacement technologies make more economic sense if they are deployed earlier in well life when there is a greater volume of recoverable resources left. For this reason, IHS Markit limited the availability of new technologies to new wells after 2018. Projects proposed to incorporate displacement technologies were restricted from benefiting from IHS Markit modeled displacement improvements. The net impact of the IHS Markit attention to deployment is that by 2030 only 66% of active production is directly impacted by the IHS Markit estimated benefits of displacement technologies. Similarly, well productivity was fixed for the life of that well based on the year it was completed. The weighted average impact is reported in Table 3.

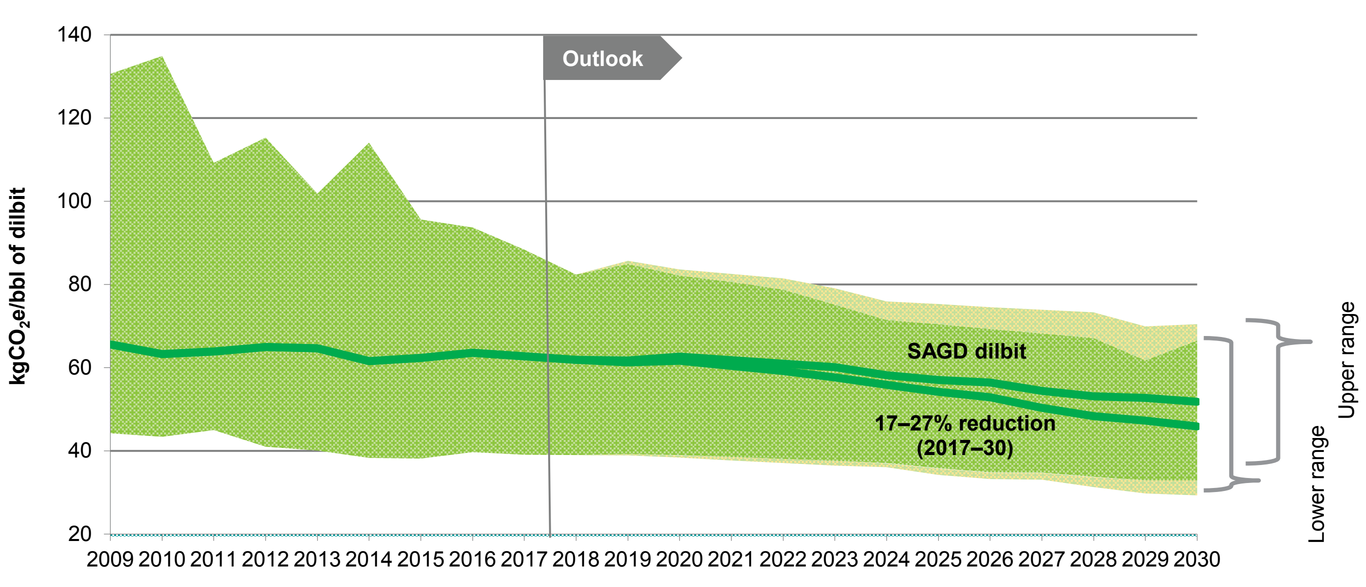
## Results: Carbon intensity of future SAGD operations

Based on IHS Markit assumptions and attention to deployment, the GHG intensity of oil sands SAGD dilbit declines from 63 kg$CO_2$e/bbl in 2017 to 46–52 kg$CO_2$e/bbl by 2030—a 17–27% reduction (see Figure 23).

The reductions relate to lower steam intensity arising from steam displacement technologies, as well as better use of natural gas from improvements in well productivity and steam generation (see Figures 24 and 25). The composition of growth (what will be developed) also contributed. This composition was arguably influenced

Figure 23

## GHG intensity of oil sands SAGD dilbit, 2009–30

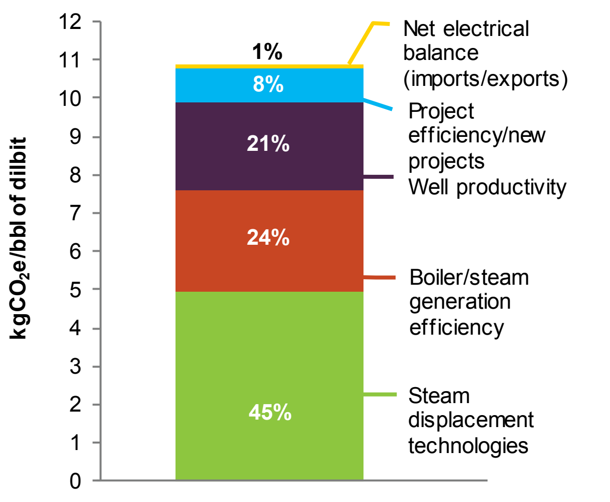



Note: CNOOC/Nexen Long Lake was not included in our estimate of SAGD GHG emission intensity. Had the facility been included, it would have increased early SAGD emission intensity because of its associated upgrader. In recent years, the facility has operated at reduced rates and without an upgrader. It would not have significantly affected current industrywide emission estimates as a result. Production is increasing in 2018, but there is currently no associated upgrader operating. Because of variability in emissions and production, the facility was not included in the SAGD estimate.
Source: IHS Markit



Figure 24

## Source of upper-bound oil sands SAGD GHG intensity improvement, 2017–30 (11 kgCO$_2$e/bbl of dilbit)

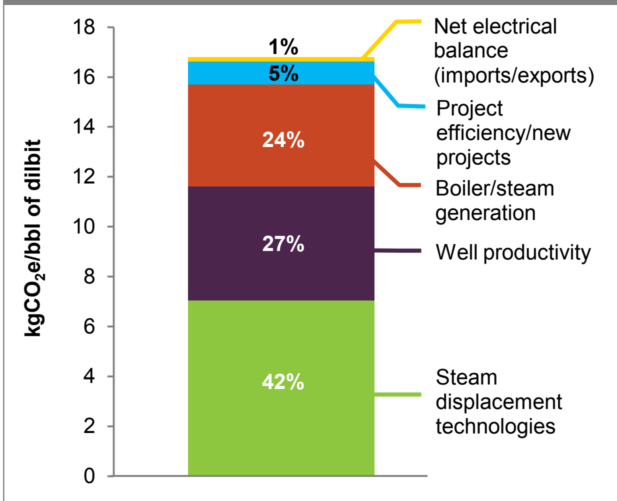



Source: IHS Markit



Figure 25

## Source of lower-bound oil sands SAGD GHG intensity improvement, 2017–30 (17 kgCO$_2$e/bbl of dilbit)




Source: IHS Markit

## Oil sands SAGD assumptions

**Well productivity.** Better understanding and drilling techniques have improved the placement of wells, while new technologies have allowed for better steam control (using steam more efficiently), expanded access to the reservoir (better conformance), and longer laterals (more oil from the same well). Innovations such as the use of infill wells have aided recovery with no net new steam requirement. Other technologies such as more durable submersible pumps, which aid in recovery, combined with predictive maintenance have reduced downtime and thus increased output. Although well productivity contributes to more efficient extraction, these improvements do not necessarily equate one-to-one with emissions. Moreover, in the absence of transformational technology, productivity gains are not inexhaustible and would slow.

**Boiler/steam generation.** Boiler efficiency is the rate of energy transfer from natural gas to steam. Over time, boilers have become more efficient. Technologies are under development that could dramatically improve this relationship. The efficiency of steam generation is affected by water quality or impurities (energy wasted on material that cannot be converted to steam). Advancements in water treatment that can improve the quality of water that moves into boilers would allow for more efficient use of natural gas.*

**Steam displacement technologies.** SAGD operates on two fundamental principles: energy (to warm and mobilize the bitumen) and pressure (to assist gravity in recovery). The steam plays both these functions. Over time, oil sands reservoirs have been found to be more insulated than once believed, and once a reservoir is at sufficient temperature, less energy may be required to maintain the reservoir temperature. SAGD producers are experimenting in the field with replacing steam with noncondensable gases and solvents. These alternative materials physically reduce steam and thus natural gas demand per barrel produced while maintaining the “gravity assist” or pressure. Solvents have the additional benefit of improving the mobility of bitumen (lowering the energy required to improve mobility). Both technologies have great potential, with the former being deployed at scale on select fields and the latter involved in advanced pilots and incorporated in two proposed projects. Methane has been the principal displacement gas used to date, but some may be experimenting with other gases. Although these technologies reduce the natural gas combustion intensity of extraction, upstream emissions are associated with the production of the coinjected material. These emissions were captured in the IHS Markit model and counted against steam displacement intensity improvements. Note that some solvent processes aspire to be 100% solvent (e.g., nsolv). These were not modeled by IHS Markit.

**Cogeneration.** SAGD operations use both boilers and cogeneration to meet steam demand. In 2017, IHS Markit estimated that installed cogeneration capacity at SAGD operations contributed to an offset credit (using the IHS Markit method) of approximately 6 $kgCO_2e$/bbl of dilbit. In recent years, the rate of installed cogeneration capacity expansion versus production growth has slowed. SAGD operations averaged about one 85 MW cogeneration unit per 56,000 b/d over the past decade and a half (2003–17), compared with one 85 MW unit per 70,000 b/d over just the past decade (2008–17). This change has tightened or eroded the benefit of electrical power exports on the GHG intensity of production. Depending on the future level of cogeneration, this trend could continue or be reversed.

*Impurities can build up in the recycled water used in oil sands extraction. These impurities cannot be converted to steam, which reduces the efficiency of steam generation.

** The comparison is based on the weighted average in 2030 of projects in the IHS Markit outlook not in operation in 2017 without any technology or efficiency improvements applied to the base operating efficiencies compared with the weighted industry average in 2017. The historical SOR is based on “ST53: Alberta In Situ Oil Sands Production Summary,” AER, https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53, retrieved 30 May 2018. The estimate of the future SAGD weighted SOR is based on the IHS Markit *North American Crude Oil Markets Canadian Fundamentals Data: First quarter 2018* and AER regulatory applications, company announcements, and websites.

### Oil sands SAGD assumptions (continued)

**Composition of growth.** The composition of new developments—which projects, how big they are, and their design efficiency—will influence the future average carbon intensity. All things being equal, new operations should be more efficient than legacy ones because they benefit the most from the latest technologies. However, reservoir quality will also influence how these facilities operate. IHS Markit assumed operations for existing SAGD expansions would be similar to the average operations of the main facility over the past three years (2015–17, adjusting for operations impacted by the 2016 Fort McMurray wildfire). For entirely new operations, IHS Markit used regulatory filings and investor relation releases to establish base efficiencies onto which new technologies or efficiencies could be modeled. In general, the weighted average SOR of new developments (before any additional assumptions were allowed to impact efficiency) was 8% lower than the industry average of 2.71 in 2017.** This would reduce overall industry intensity should the growth occur as IHS Markit envisions. In this way, the greater the potential growth, the greater the potential for GHG emission intensity reductions.

by lower prices, resulting in more focused development of more efficient projects in the IHS Markit outlook. Examples include projects designed to incorporate solvent extraction technologies from the start. The stronger technology assumptions in the lower-bound case diminished the relative significance of the impact of new projects, which do not change between our cases (see Table 3).

An interesting result, however, was that our assumption about future expansion of cogeneration capacity was not sufficient to materially contribute to lower GHG emission intensity. This was related to the value of the electrical exports we chose. A higher value would generate different results. For more details, see Appendix A.

## Concluding remarks and comparisons

This section discusses some of the implications, including presenting the results on an upstream or production industry average basis and a full-cycle basis by drawing upon prior IHS Markit research.

### An industry average

Rolling up our results, we created overall oil sands average intensity. Over the past (near) decade (2009–17), the average upstream GHG intensity of oil sands extraction (using system boundaries consistent with a life-cycle basis) fell 21%—led by oil sands mining. This trend is expected to continue, with many improvements already in motion. Examples included the planned expansion of mining cogeneration capacity that could further reduce petroleum coke use, the ongoing ramp-up and expansion of newer mining operations with lower GHG emission intensities, and the deployment of steam displacement technologies among in situ operations. These factors, when coupled with a reasonable pace of technology development and efficiency deployment, could further reduce the oil sands GHG emission intensity by 16–23% by 2030 (see Figure 26). Certainly, this is a forecast, and the reality will differ from our projections. Yet, the lack of transformational technologies in our outlook, many of which are in advanced pilots and demonstrations, such as in-pit mine face extraction, could lead to much more dramatic results.[18]

### Variability in the oil sands

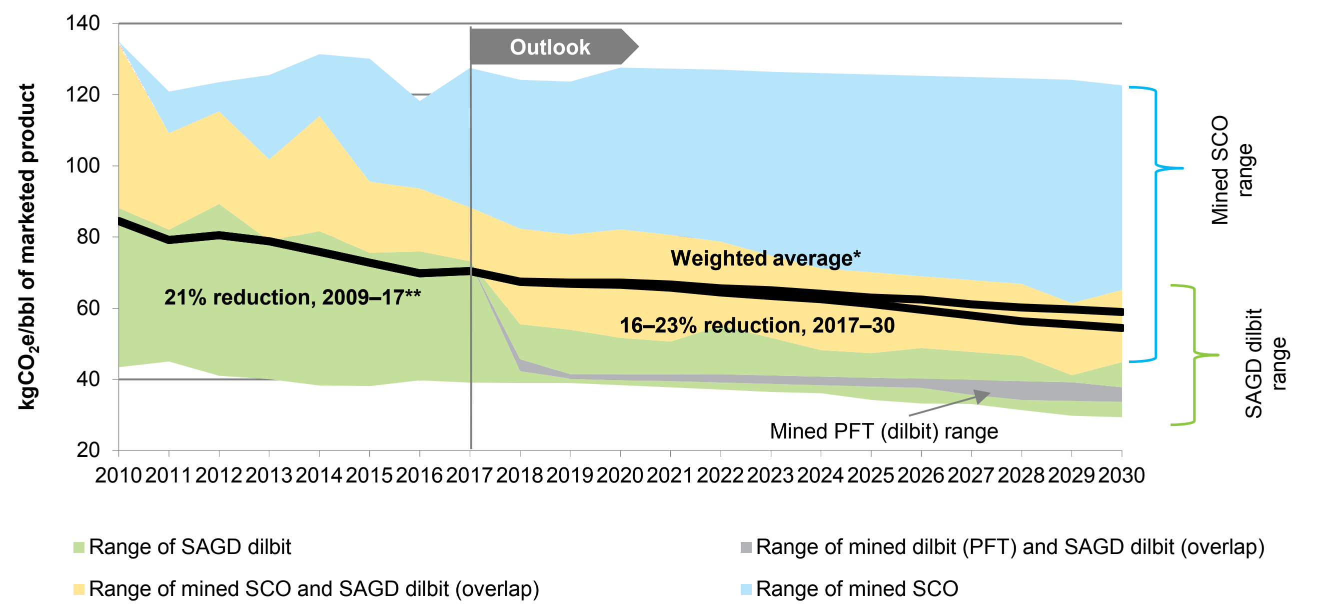
This report has focused on estimating the average upstream GHG intensity of the oil sands by extraction process and marketed product (CSS dilbit, SAGD dilbit, mined SCO, and mined dilbit). Yet, within any region or play there is considerable variability in operations and performance. This is equally true in the Canadian oil

18. For more information on in-pit mine face extraction, see "In-Pit Extraction Process," Emissions Reduction Alberta, http://eralberta.ca/projects/details/in-pit-extraction-process, retrieved 3 August 2018.

Figure 26

**Average and full range of oil sands GHG emission intensity by year, 2010–30 ($kgCO_2e$/bbl of marketed product)**




*Estimate of total oil sands average includes oil sands CSS dilbit, SAGD dilbit, mined SCO, mined dilbit, primary, experimental, and EOR. Historical estimates for CSS were included with no intensity improvement after 2017. Estimates for primary were taken from a prior IHS Markit report (cited at the end of this note) with the same values being applied to experimental and EOR. Primary, experimental, and EOR accounted for about 7% of oil sands production in 2017 (18% including CSS), declining to 5% by 2030 (11% including CSS). Ranges shown for mined dilbit (PFT), SAGD dilbit, and mined SCO range from lower-bound minimum to upper-bound maximum. Note that prior to 2018, there was only one operating mined dilbit (PFT) facility and thus no range. Source of prior estimates IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*, www.ihsmarkit.com/oilsandsdialogue.
**Note that 2009 is not shown in this figure but is in Appendix A.

Source: IHS Markit



sands and is clearly visible in Figure 26. In 2017, IHS Markit estimates the full range of upstream GHG intensity of oil sands production (on a marketed product basis) spanned 88 $kgCO_2e$/bbl—from 39 $kgCO_2e$/bbl to 127 $kgCO_2e$/bbl. This range highlights that the average is not the reality for many operations and that caution should be exercised when considering averages.

## The oil sands on a full life-cycle basis

Given the scope and complexity of this report, we could not include an update to the downstream components of a full life-cycle basis or update our estimate of the average crude oil refined in the United States (the US average). However, by sourcing downstream estimates of transportation and refining emissions from our prior study, we could include an estimate of the full life-cycle GHG intensity for mined SCO, mined dilbit (PFT), and SAGD dilbit, as well as a range from the minimum to maximum intensity (see Figure 27).[19]

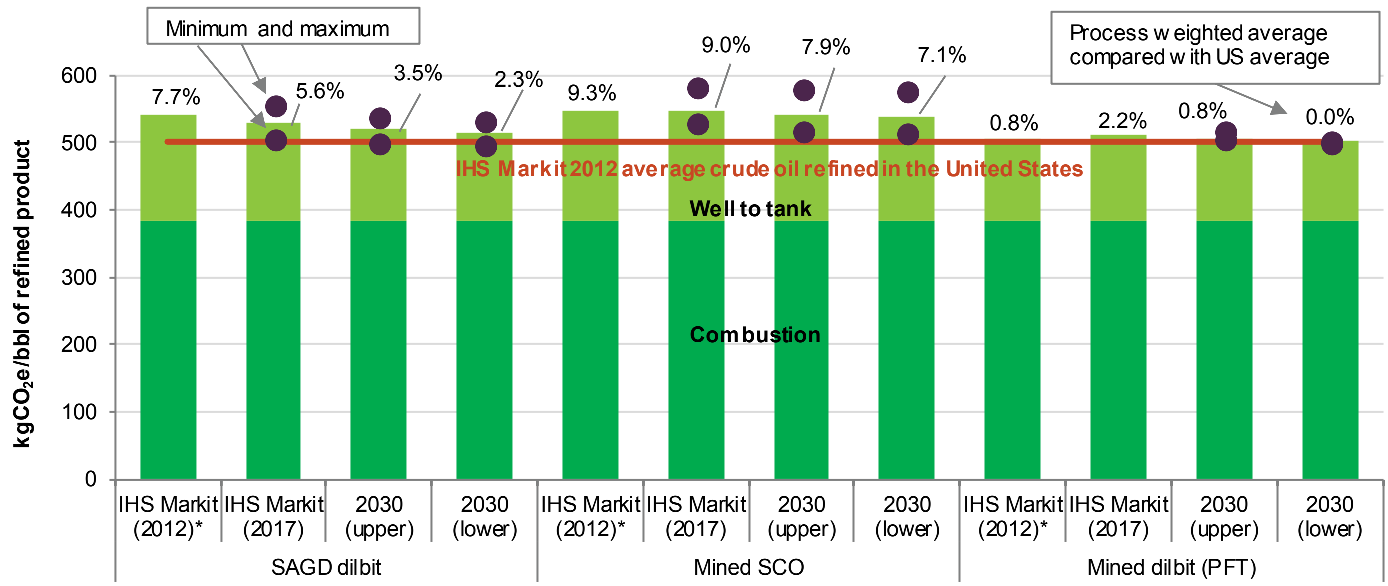
Interestingly, the lower end of the IHS Markit estimate of oil sands GHG emission intensity indicates that some facilities, when placed on a full life-cycle basis, are already (in 2017) comparable to the US average. Discussion of each stream is included below:

- **SAGD dilbit.** Compared with our prior 2012 estimate, our SAGD dilbit emission intensity is lower. Assuming the US average remains relatively static, the SAGD dilbit average emission intensity would decline to within 2–4% of the US average.

19. Source of prior estimates: IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*.

Figure 27

**Oil sands life-cycle GHG emission cases compared**




*The completion of the full life-cycle assessment for "IHS Markit (2017)," "2030 (upper)," and "2030 (lower)" incorporated crude transport, crude refining, and refined product transport sourced from the prior IHS Markit Strategic Report *IHS Oil Sands Dialogue: Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*, www.ihsmarkit.com/oilsandsdialogue. "IHS Markit (2012)" and "IHS Markit 2012 average crude oil refined in the United States" were also sourced from the same study. The US average is based on the year 2012. IHS Markit acknowledges that it could evolve over time. There was no feasible way to account for this variance in this study. However, one of the conclusions of the prior IHS Markit study cited here already was that although US production changed considerably between 2005 and 2012, the US average remained relatively constant as refinery runs continued to process similar crudes, albeit from different supply sources.

Source: IHS Markit



- **Mined SCO.** The mined SCO emission intensity was nearly identical between our current estimate and prior estimate. On a full life-cycle basis, mined SCO emission intensity declines 1–2% against the US average. This arguably reflects the limited assumptions we modeled for mined SCO and the relative share of upstream emissions over total life-cycle emissions.
- **Mined dilbit**. Production of mined dilbit (PFT) did not start until 2013, and our prior estimate was of a fully ramped-up facility. However, normalization of output does not appear to have yet been achieved with mined dilbit (PFT), as evidenced in the higher estimate of GHG emission intensity than our 2012 estimate. Over time, the mined dilbit (PFT) emission intensity will fall to be on a par with the US average.[20]

## Concluding thoughts

This study reviewed the historical GHG emission intensity of upstream oil sands extraction and the factors that could shape its future. Prior IHS Markit analysis has shown the oil sands to be within the range of other crude oils refined in North America. This study shows that upstream oil sands GHG intensity has been declining. On average, upstream emissions are one-fifth lower than a decade ago and could fall another approximately 20% over the coming decade. On a full life-cycle basis, this would bring the industry closer to the US average. However, averages do not capture the entire picture, with some facilities already at or near the US average today. Still, this is a forecast. Challenges remain, and work still needs to be done. However, the absence, with few exceptions, of transformational technologies in this study—even though many are advancing—may indicate a greater potential for reductions than shown in our results.

20. Depending on the severity of the PFT process, bitumen quality can be impacted. This can affect downstream refining emissions. The IHS Markit use of prior downstream mined dilbit (PFT) emissions did not consider this potential, and a lower total life cycle could result than our estimate.

## IHS Markit team[21]

**Kevin Birn,** vice president, IHS Markit, is part of the IHS Markit North American Crude Oil Markets team and leads the IHS Markit Oil Sands Dialogue. Mr. Birn is responsible for a team of oil market analysts focused on western Canada. He has authored numerous reports associated with the development of the Canadian oil sands. His expertise includes Canadian oil sands development, oil sands cost and competitiveness, crude oil markets, crude oil transportation logistics, GHG intensity of crude oil, and Canadian energy and climate policy. Mr. Birn has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US secretary of energy. Prior to joining IHS Markit, Mr. Birn was a senior economist with the Government of Canada and a partner in a software firm. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta.

21. Special thank you to former IHS Markit colleague Hossein Safaei, the original architect of IHS Markit upstream oil sands greenhouse gas (GHG) intensity models.

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IHS Markit™

# Looking north

## A US perspective on Canadian heavy oil

November 2018

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Director

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Vice President*

*A special thanks to Steve Fekete, Executive Director, Consulting, for contributing to this report.

Canadian Oil Sands Dialogue | Strategic Report

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# Looking north

## A US perspective on Canadian heavy oil

### About this report

**Purpose.** Since 2009, IHS Markit has provided research on issues surrounding the development of the Canadian oil sands. This is the second of two reports exploring the relationship between US heavy oil demand and Canadian heavy oil supply. The renaissance in the US hydrocarbon production has changed the world. However, US demand and import of heavier crude oils have persisted, with Canada taking on an increasing share and role in the US market. This report will explore the outlook for US heavy oil demand.

**Context.** This report is part of a series of reports from the IHS Markit Canadian Oil Sands 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, refiners, and nongovernmental organizations.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a workshop held in Washington, DC, on 7 November 2017, as well as participant feedback on a draft of the report. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for a list of participants and the IHS Markit team).

**Structure.** This report has six sections.

1. Introduction
2. The United States is the world's largest heavy oil market
3. The historical role of Canadian heavy oil in the United States
4. The history of US heavy oil demand
5. The global heavy oil market has tightened
6. The importance of Canadian heavy oil imports has risen

# Looking north

## A US perspective on Canadian heavy oil

### Key implications

The renaissance of US hydrocarbon production has changed the world. However, US demand and import of heavier crude oils have persisted. In 2018, US refiners will process nearly 17 MMb/d of crude oil. About half of this volume will be imported, and more than half of all imports are heavy oil. A key growing source of US oil imports has come from Canada. This report explores the US demand for and relationship with heavy oil and the role that Canadian heavy oil plays in the United States.

- **The United States is the world's largest market for heavy oil.** Over the past 40 years, the US refining complex has invested in expanding its ability to process heavy oil, first from Latin America and later from Canada. This fact has not only made the United States the world's largest market for heavy oil but has also given US refineries a competitive advantage. In 2018, the United States will demand more than 5 MMb/d of heavy oil.

- **As tight oil has risen, the global heavy oil supply may have tightened because key sources of heavy supply have declined.** Some factors contributing to a tightening heavy oil market may be short-lived, such as heavy oil cuts by OPEC, while others may be more protracted, such as the collapse of Venezuelan heavy oil output—heavy alone, down nearly 500,000 b/d since 2014.

- **Lacking alternative markets, growing heavy oil supply from Canada has taken on an increasing role in meeting US demand.** In 2018, the United States will import more than 3.6 MMb/d from Canada—more than any other nation, even the combined imports from all of OPEC. Most of these imports—four-fifths—will be heavy oil.

- **Canadian heavy crude oil fits an important supply gap for US refiners designed to process heavy oil.** At the same time that US production of light oil has grown, the relative importance of Canadian heavy oil to the United States has increased. The United States will soon become the largest crude oil producer in the world, but that growth is from light crude oil. In the absence of Canadian supply, heavy oil may otherwise be more scarce and expensive to US refiners.

—November 2018

# Looking north

## A US perspective on Canadian heavy oil

**Vijay Muralidharan,** Director

**Kevin Birn,** Vice President

## Introduction

The renaissance of US hydrocarbon production has changed the world, but the impact has not been borne evenly across the oil market. The revival and abundance of US supply has come from tight oil, a light, sweet crude oil. However, US refineries are designed to process a range of crude oils—from light to heavy. The impact has backed out almost all offshore imports of similar quality crude oil, but imports of heavier grades—medium to heavy—have persisted.

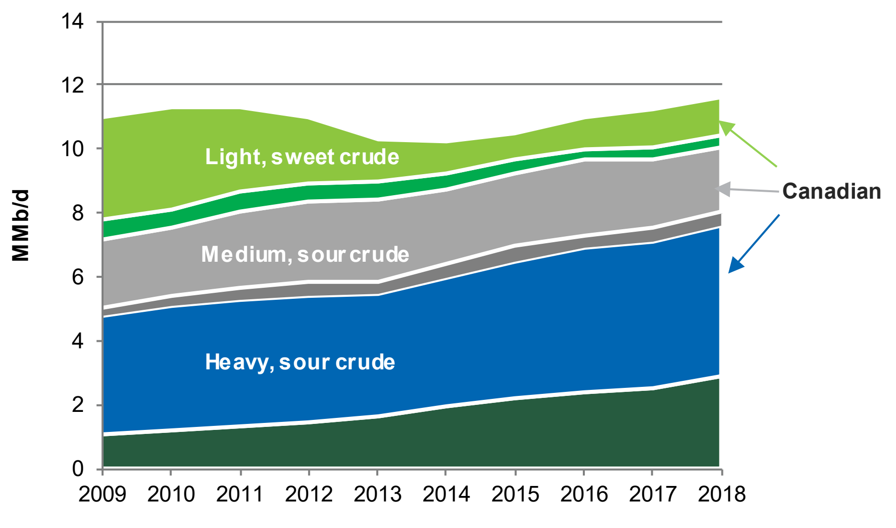
In 2018, IHS Markit estimates that US refineries will process nearly 17 MMb/d of crude oil. Of this volume, less than half will be light oil; a quarter medium; and the remaining third heavy. Over the past decade, from 2009 to 2018, imports of light, sweet crude oil fell 1.5 MMb/d while demand increased 1.5 MMb/d. Meanwhile, demand and imports of heavier and/or sourer crude oils increased by more than 200,000 b/d.

Lacking alternative markets and with growth dominated by heavy crude oil, Canada has taken on an increasing role in meeting US demand (see Figure 1). In fact, in 2015 imports from Canada overtook the combined imports of all of OPEC to the United States.[1]

All indications are that US output will continue to rise. Having nearly saturated all US demand for light oil, increasing volumes are expected to move offshore. Indeed, US exports of crude oil doubled between 2016 and 2017 to about 1.1 MMb/d and have averaged about 1.8 MMb/d in 2018.[2] Meanwhile, the key sources of heavy oil have declined, and the relative importance of Canadian, both volumetrically and in meeting the need of specialized complex refineries in the United States, has increased.

Figure 1

US crude import by type, 2009–18




Source: IHS Markit

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This report is the second in a series looking at the interdependence and outlook for North American heavy supply and demand. The first report, *Looking south: A Canadian perspective on the US Gulf Coast heavy oil market,* looked at the potential of the US

1. Source: Energy Information Administration (EIA), "U.S. Imports by Country of Origin," www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epc0_im0_mbblpd_a.htm, retrieved 16 July 2018.

2. Source: EIA, "Exports," https://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS-Z00_mbblpd_a.htm, retrieved 5 October 2018.

market from a Canadian export perspective.[3] This report takes the opposite perspective: what do US refineries want, why heavy oil, and how much?

Throughout this report, numerous terms relating to crude quality, value, and processing are discussed. For simplicity, heavy, sour crude oil—the dominant form of Canadian output and exports to the United States—will be referred to as just heavy crude oil or heavy oil. More information on crude quality and refining is available in the box "Refining 101: Crude quality matters."

## The United States is the world's largest heavy oil market

In 2018, IHS Markit estimates that the global refining system will process about 85 MMb/d of crude oil and condensate.[4] As shown in Figure 2, nearly 10 MMb/d, or 12%, of this result is heavy crude oil.

Over the past decade, global heavy oil demand has increased. As shown in Figure 3, from 2009 to 2018 demand rose from 7.0 MMb/d to 9.6 MMb/d. During this period, growth in heavy oil demand in Asia doubled from 1 MMb/d to 2 MMb/d. This result was closely followed by North America, nearly all occurring in the United States, where heavy oil processing expanded by just over 1.0 MMb/d, to reach 5.3 MMb/d in 2018.

By a wide margin, the United States remains the largest market for heavy crude oil. As shown in Figure 3, more than half of all heavy oil globally was processed in North America in 2018, predominantly the United States.

The majority of the heavy oil processing is occurring on the USGC, followed by the Midwest and the West Coast. As shown in Figure 4, the USGC region has processed more than half of all US heavy oil demand in 2018, or 2.7 MMb/d. In 2018, the Midwest has processed 1.3 MMb/d, while the West Coast (California and Washington State specifically) has accounted for just under 700,000 b/d.

Processing in the remaining regions, the East Coast and Rockies, is smaller and geared more toward lighter oils. In 2018, the two regions processed just over 400,000 b/d of heavy oil.

## The historical role of Canadian heavy oil in the United States

Canadian heavy oil imports have traditionally found a home in the Midwest, with offshore suppliers from Mexico, Venezuela, and the Middle East meeting the needs of the USGC. Today, the Midwest region may have hit its maximum capacity to consume more heavy oil from Canada (and elsewhere). Growing Canadian heavy supply has been making its way down to the USGC at the same time that key sources of Latin American heavy oil, namely Venezuelan and Mexican supply, have declined. In fact, IHS Markit estimates that current consumption of Canadian crude on the USGC may already be in excess of 800,000 b/d—far greater than headline EIA import data would indicate—owing to commingling, storage, and internal transfers within the United States.[5]

Meanwhile, to date, logistical issues have impaired the ability of meaningful volumes of Canadian supply to access the US West Coast and East Coast markets. Although some limited rail has made its way from Canada to the US East Coast, this market traditionally processes lighter crudes and lacks the complexity for heavier grades of oil. On the US West Coast, the majority of heavy demand has been met by domestic Californian or Alaskan output. However, as Californian and Alaskan production has slowly declined, offshore imports have

3. For more information, this report can be accessed here: www.ihsmarkit.com/oilsandsdialogue.

4. This estimate does not include biofuels/NGLs and other petroleum products.

5. The EIA tracks overland crude oil imports when they "break bulk," meaning when the crude oil is unloaded or leaves the pipeline. IHS Markit believes that Canadian heavy oil imports may be "stopping off" at Cushing, which would result in a reported delivery into PADD 2 as opposed to PADD 3.

## Refining 101: Crude quality matters

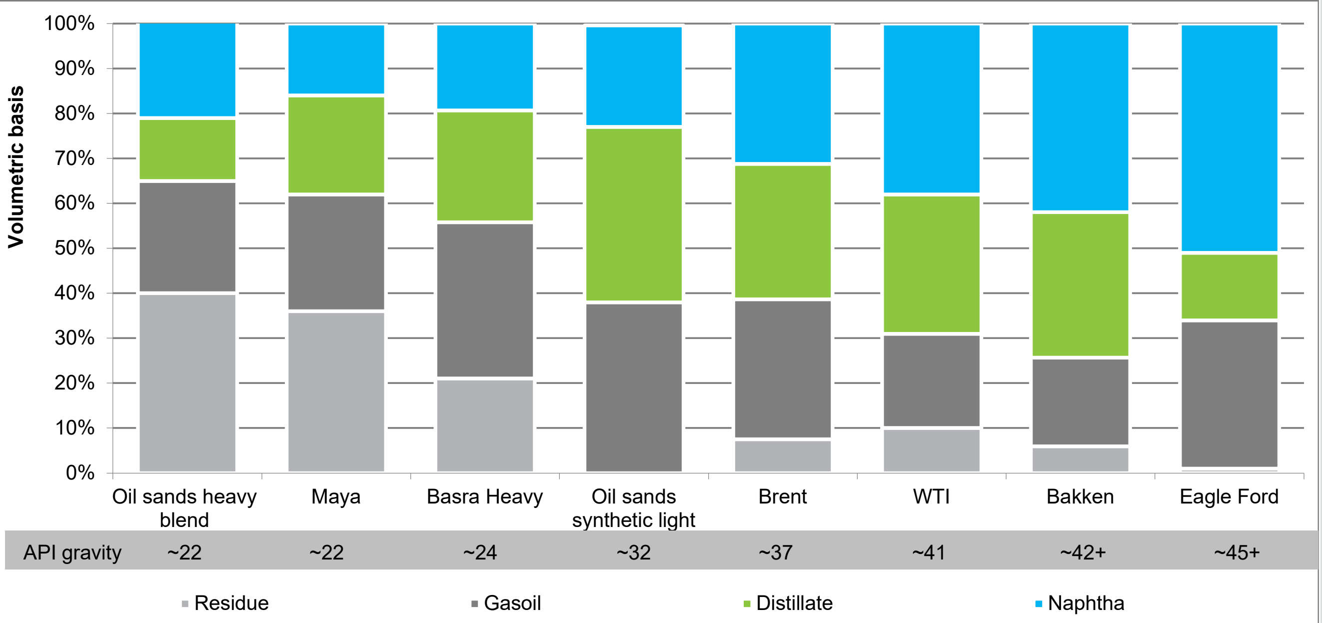
Crude oil is not homogeneous. It is commonly differentiated by density—light or heavy—and impurities, most notably sulfur—sweet or sour. API gravity is a common measure of density. IHS Markit defines heavy crudes as those with an API gravity of 24° or less, light crudes as those with an API gravity of 32° or greater, and everything in between as medium.

Notwithstanding the global value of crude oil, the relative value refiners place on different quality crude depends on how much effort it takes to convert it into higher-value refined products and the type of products that can be derived from it. Crude oil will differ by its composition and/or groupings of similar hydrocarbons (known as fractions). Lighter fractions, such as naphtha and distillate, boil at lower temperatures and are in a general sense more easily converted into higher-value refined products such as gasoline and jet fuel. Heavier fractions, such as residue and gasoil, boil at higher temperatures. Figure B1 illustrates the distribution of various fractions for a select set of crude oils, ordered from left to right and from heavy to light.

The heaviest fractions (i.e., residue, shown in light gray in Figure B1) require specialized processing units capable of reaching the temperature and pressure needed to break or convert these more complex hydrocarbons into lighter fractions, which can then be converted into gasoline and diesel. Heavier crude oils typically have a greater share or fraction of heavier molecules such as residue. Refiners that lack heavy crude oil processing capacity are unable to process the heaviest fractions and face selling a larger share of the barrel they purchased at a lower value. Heavy crude oil refineries—the types best suited to process such crudes—are generally known as complex refineries.

Figure B1

**Assay of select crudes**



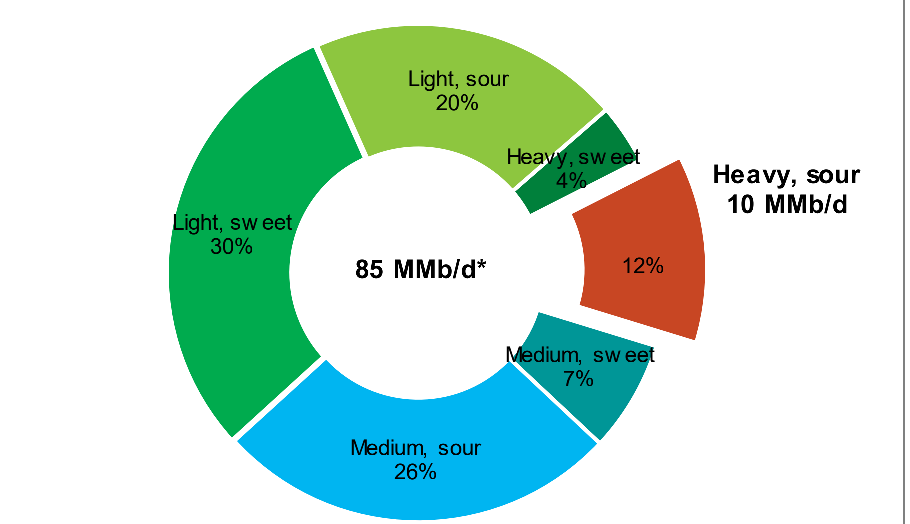

Note: Crude assays will vary. Values are approximations and will vary by cut point and reservoir quality, which does vary across a play and over time. Estimates are assembled from various sources and adjusted based on feedback.
Source: Derived and adapted from IHS Markit, EIA, BP Global Energy Trading, and CrudeMonitor.ca

crept up, which could provide future opportunities for Canadian heavy oil.

## The history of US heavy oil demand

Figure 2

Global refinery runs by quality in 2018




*The total global refinery runs include crude oil and condensate.
Source: IHS Markit

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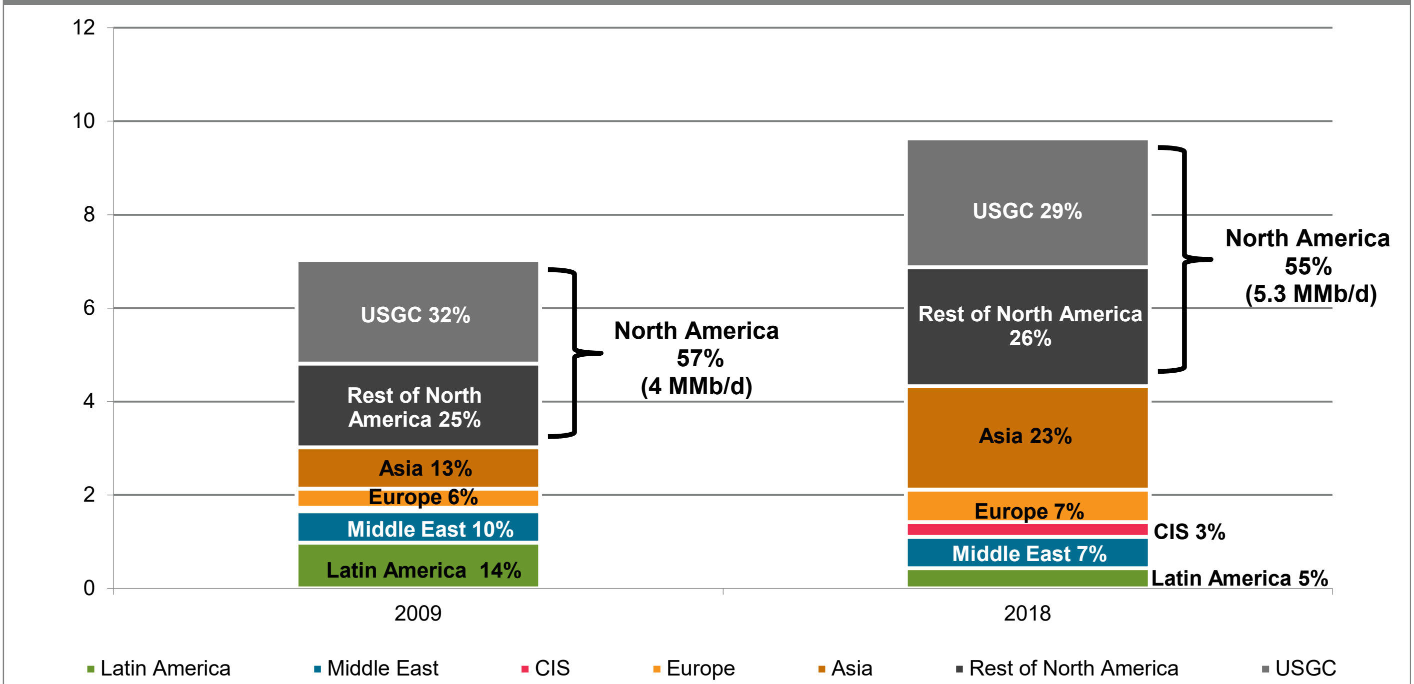
Refining is a complex and ever-changing business. Over time, refineries invest to better tailor their facilities to available feedstock and refined products in demand. Prior to the advent of US tight oil and the revival of US supply, domestic US production was in long-term decline. After peaking in the early 1970s, US crude oil production entered a 40-year decline.[6] Moreover, the world thought it was running out of lighter grades of crude oil. US refiners faced with the prospect of continued reductions in the availability of domestic supply looked increasingly offshore. Infrastructure was built to deliver increasing volumes inland from offshore. US imports of foreign crude oil increased, reaching a rough plateau between 2004 and 2007 at

Figure 3

Global heavy oil demand, 2009 and 2018




Note: CIS = Commonwealth of Independent States; USGC = US Gulf Coast.
Source: IHS Markit

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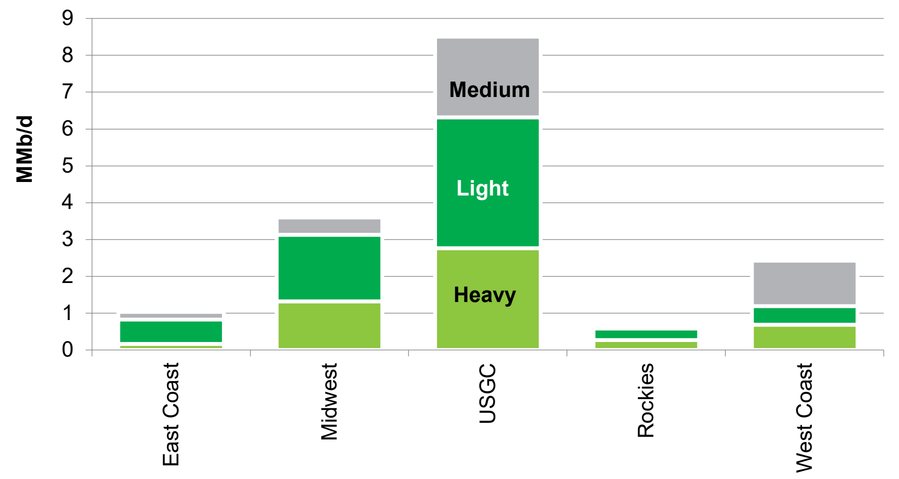
6. The estimate does not include NGLs, biofuels, and other petroleum products. Source: EIA, “Crude Oil Production,” https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm, retrieved 5 September 2018.

more than 10 MMb/d.[7] Deposits of heavy crude in Mexico, Venezuela, and Canada were viewed as a limited set of resources globally capable of meaningful production growth. Heavy oil supply expanded in these regions, first in Latin America and then later in Canada.

These conditions set the stage for an expansion of US heavy crude oil refining capacity. Over the past 30 years, heavy oil processing capacity expanded from about 1.5 MMb/d to 2.5 MMb/d (from 1990 to 2018).[8] This expansion occurred during two distinctive periods, first on the USGC and then later in the US Midwest.

Figure 4

US crude consumption by type and region




Note: Light and medium, sweet barrels are categorized as light, whereas medium and light, sour barrels are classified as medium.
Source: IHS Markit

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## Latin American JVs and supply agreements lead to a heavy oil expansion in the USGC

The first period of heavy oil processing expansion occurred during the 1990s. Faced with declining domestic production, US refiners looked offshore for supply. Meanwhile, Latin American heavy oil production was on the rise, but was limited in the number of markets capable of economically processing the crude oil. Many refiners entered into JVs and/or supply arrangements that provided crude oil at prices that supported the refinery investment necessary to convert heavier crude oils into refined products. In exchange, the producers received security of demand for their output. Most of the expansion that occurred during this period happened on the USGC and to a lesser extent in the Midwest and on the West Coast. Gradually, these arrangements unwound, as the terms expired in the early 2000s and because of the rise of alternative sources of heavy oil from places such as Canada. Nevertheless, as seen in Figure 5, investments resulted in an expansion of heavy oil processing capacity from just over 1.5 MMb/d in the early 1990s to more than 2.1 MMb/d in the early 2000s. Correspondingly, US heavy oil processing (demand) climbed from 2.5 MMb/d to 3.9 MMb/d from 1990 to 2001 (approximate period of these contracts).[9]

## Canadian supply fueled a heavy oil expansion in the Midwest

The second wave of expansion began to emerge in the mid-2000s and lasted just over a decade. The dawn of the millennium brought the development of the first commercial steam-assisted gravity drainage (SAGD) project in the Canadian oil sands. This development unlocked the majority of the resource potential in the oil sands. Unlike oil sands mining, which dominated at the time and marketed a light synthetic crude oil (SCO), SAGD plants predominantly marketed heavier bitumen blends. Investment increased in the Canadian oil sands, and production grew.

7. The estimate includes only crude oil, not NGLs, biofuels, and other petroleum products. Source: EIA, "U.S. Imports by Country of Origin," www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbblpd_a.htm, retrieved 16 July 2018.

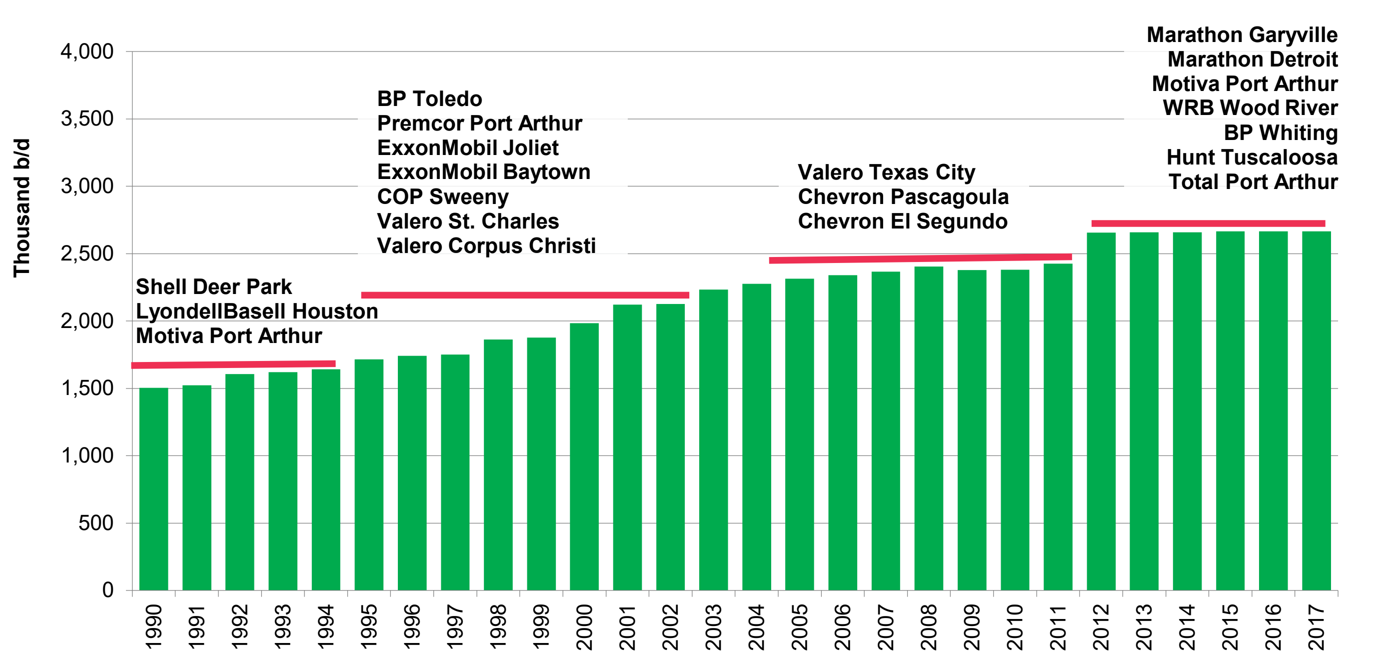
8. The estimate is based on coking capacity. Generally, total heavy oil demand need not be the same as total heavy oil processing capacity (coking capacity), given that only the residual, which is a fraction of the heavy barrel, needs to be processed through cokers.

9. Heavy oil processing capacity typically relates to coking capacity. A coker is a specialized refinery processing unit capable of achieving the environment necessary to process the heaviest fractions in crude oil. Because crude oil varies in the share of these heavy fractions even within heavy crude oil, heavy oil processing can be greater than coking capacity. Moreover, there are other heavy oil processing technologies, but, by far, coking is the most common.

Figure 5

**US heavy oil conversion (coking) capacity over time**




Note: COP = ConocoPhillips.
Source: IHS Markit



From 2001 to 2018, the Canadian oil sands supply expanded 2.2 MMb/d, and increasing volumes headed south. A wide price difference between light and heavy crude oil incentivized an expansion in the US Midwest to process greater volumes of lower-cost heavy, sour crude oil from Canada (and in Canada in upgrading bitumen into light SCO).[10] To a lesser extent, some investments were also made in the USGC. The majority of the expansion occurred in the US Midwest and USGC.

Throughout this period, less complex, smaller refining operations have generally given way to larger, more complex operations. Complex refiners are benefiting from the ability to optimize over a greater range of feedstock (or crude quality) while expanding in size to capture greater economies of scale. Over the past decade, from 2009 to 2018, three-quarters of more than 1 MMb/d of refinery capacity that has been rationalized came from less complex crude distillation units.

## The global heavy oil market has tightened

The conditions that gave rise to the expansion of US heavy oil demand over the past 40 years have changed. The world has found itself flush with light oil, while the relative availability of heavy oil has tightened. This result has reduced the price difference between light and heavy crude oil globally and thus the incentive in further investments in heavy oil processing capacity—particularly in North America.

10. SCO is a light crude oil produced from bitumen via specialized heavy oil refinery conversion units, known as upgraders, which turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. From 2001 to 2018, investments in oil sands upgrading increased overall SCO production by more than 600,000 b/d, to about 1 MMb/d, and a new heavy oil refinery was completed in 2017.

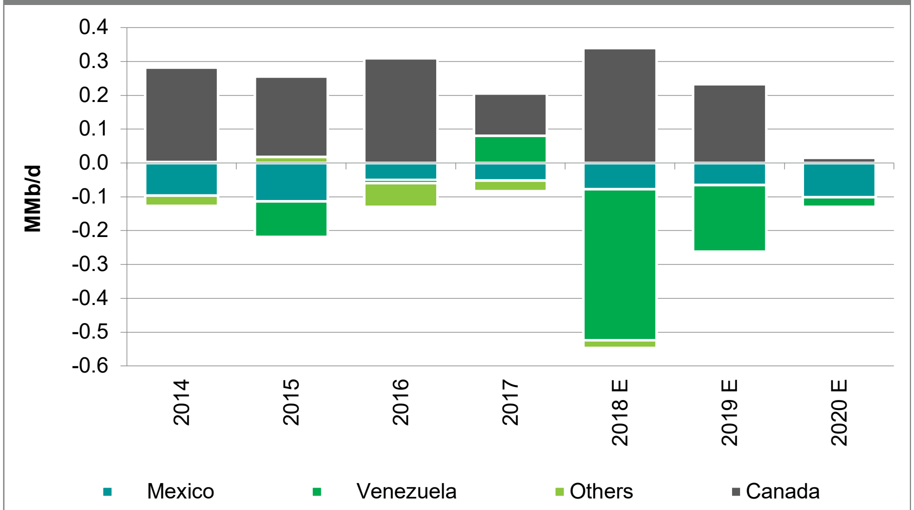
The rise of tight oil is well documented, while the tightening of the heavy crude oil market has come about from the accelerated declines of key sources of heavy crude oil, OPEC production restraint, and the ongoing expansion of heavy oil processing capacity elsewhere in the world. Below are some key contributing factors:

- **Expanding Russian heavy oil capacity.** Changes to Russian fiscal policy have incentivized Russian refineries to process more of the heavier fractions that would otherwise be exported. This has reduced the availability of heavy bottom material, which traditionally would have been processed in Europe. Consequently, there has been increasing demand for heavy bottom fractions globally, which are typically found to a greater degree in heavier grades of oil. IHS Markit estimates that from 2013 to 2017, more than 300,000 b/d of heavy bottom processing capacity has been implemented in Russia, with additional investments under way or planned before 2020.[11]

- **Lower heavy oil supply due to OPEC cutbacks, decay of the Venezuelan oil sector, and falling Mexican output.** The 1.8 MMb/d of crude oil supply cuts that were agreed to by OPEC and numerous non-OPEC countries in 2017–18 have been borne to a greater degree by heavier crude oils. Although the cuts have been rolled back, Venezuela's heavy oil production continues to fall owing to a lack of investment and decay. Also, Mexican heavy oil production has been in steady decline for more than a decade. Mexico has liberalized and opened its upstream oil sector to help arrest and reverse these declines. To date, there has been considerable interest by international investors in the Mexican upstream sector. However, any reversal will take time, and there is no guarantee that heavy oil will be the beneficiary with considerable interest in lighter plays. As shown in Figure 6, Latin American heavy oil output has declined about 900,000 b/d over the past four years (from 2014 to 2018, or since the oil price collapse began in 2014) and could decline by another 500,000 b/d by 2020. Venezuela alone has lost about 500,000 b/d of heavy oil since 2014. The only source of material heavy crude oil growth globally has come from Canada.

Figure 6

Year-on-year annual change in heavy production from 2014 to 2020




Note: E = estimate.
Source: IHS Markit



## The importance of Canadian heavy oil imports has risen

The historical incentives that led to the expansion of heavy oil processing capacity in the United States have subsided in the past few years. The economics of investing in heavy oil conversion capacity are predicated on the anticipated savings in being able to convert heavier crude oils that typically trade at a discount to lighter grades into higher-value refined products. The rise of light, tight oil in great abundance and the contraction (temporary or otherwise) in the availability of heavy oil globally have reduced the price difference (and future

11. Heavy bottom processing capacity includes coking and hydrocracking. The value represents only the heaviest components of a barrel of crude oil.

expectation) between light and heavy crude oil. Over 2017, the price of Mexican Maya—a globally traded heavy oil—averaged about $7/bbl lower than Light Louisiana Sweet—a globally traded light crude oil on the USGC—compared with a historical five-year average of $9/bbl.[12] Moreover, anecdotally, there have been instances in 2018 where the price of Canadian heavy oil in Houston has traded at a premium to WTI, Cushing.

The presence of light, tight oil in great abundance will encourage US refiners—big and small—complex or not—to process more of it. Investments will be made to widen out the top end of refiners—to process crude oil with a larger share of light ends—such as are found in the Permian.

However, facilities that have invested in heavy oil processing capacity are not expected to go backward or "uncomplicate" themselves. These investments, which can be significant at well over US$1 billion to integrate a heavy oil conversion unit known as a coker, give a refinery greater flexibility to optimize over a greater range of feedstock. This situation has historically given the USGC (and other heavy complex refiners) a competitive advantage that has allowed the region to expand output and increase market share in the United States and abroad. It will not wish to idle this capacity.

A key question that has emerged as a result of the accelerating uncertainty over the future output of Venezuela—one of the largest historical producers of heavy oil in the world—is the adequacy of heavy oil supply going forward, a situation that is clearly visible in Figure 6.

Through this period, the importance of Canadian heavy oil has arguably risen. Canada has become the largest producer of heavy crude oil in the world and over the past few years the only source of material heavy growth globally. To date, IHS Markit believes rising Canadian heavy supply—which increased 1.1 MMb/d from 2012 to 2017—has managed to offset most of the contraction in heavy oil supply globally. Additionally, Canada's market share in the United States has expanded, offsetting and/or displacing offshore imports from Latin America and elsewhere. This result has shored up the US heavy oil market to date.

Looking to the future, there are valid questions about the future balance of the heavy oil market. Venezuelan output is increasingly unreliable and uncertain, and it may well get worse before a recovery can be mounted. In turn, any recovery depends on broader political and economic reforms in Venezuela, which will take time. IHS Markit expects Canadian heavy oil imports will be increasingly in demand in the United States, expanding from 2.5 MMb/d in 2017 to more than 3.0 MMb/d in 2020. However, the pace of Canadian heavy oil growth is also set to slow owing to the declining level of oil sands projects under active development. IHS Markit expects new oil sands projects will advance in the next few years. Yet with oil sands projects taking two years or more before production can be brought online, a slower period of growth at least to the early part of the next decade is almost assured. OPEC could help moderate the heavy oil market, but there are quality differences between Middle Eastern heavy oil and the much heavier grades found in the Americas. If this trend continues, it could set the stage for a protracted period of a tighter heavy oil market in the world and a greater importance for Canadian output to US refiners—at least in the medium term.

12. Differentials have widened closer to historical relationships for Mexican Maya in 2018. However, inland US crude congestion contributed to both distortions to US crude benchmarks and the formula used to set Mexican Maya.

## Report participants and reviewers

IHS Markit hosted a focus group meeting in Washington, DC, on 7 November 2017 to provide an opportunity for stakeholders to come together and discuss the future of the US heavy oil market. Numerous participants also reviewed a draft 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 Markit is exclusively responsible for the content of this report.

**Alberta Department of Energy**

**Alberta Innovates**

**Canadian Association of Petroleum Producers**

**Cenovus Energy**

**Inter-American Dialogue**

**Natural Resources Canada**

**Suncor Energy**

**TransCanada Corporation**

## IHS Markit team

**Kevin Birn**, vice president, IHS Markit, is part of the IHS Markit North American Crude Oil Markets team and leads the IHS Markit Oil Sands Dialogue. Mr. Birn is responsible for a team of oil market analysts focused on western Canada. Mr. Birn has authored more than 50 reports related to the western Canadian oil market as well as the development of the Canadian oil sands. His expertise includes Canadian oil sands development, oil sands cost and competitiveness, crude oil markets, crude oil transportation logistics, greenhouse gas intensity of crude oil, and Canadian energy and climate policy. Mr. Birn has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US secretary of energy. Prior to joining IHS Markit, Mr. Birn was a senior economist with the Government of Canada and a partner in a software firm. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta.

**Vijay Muralidharan**, director, IHS Markit, is part of the IHS Markit North American Crude Oil Markets team and is an integral part of the IHS Markit Oil Sands Dialogue. Mr. Muralidharan has more than 12 years of experience in upstream, midstream, and downstream global oil and gas economic evaluation. His expertise includes crude oil market analysis, macroeconomics, risk analysis, oil asset evaluation, technology, crude oil logistics, and Canadian energy and climate policy. Prior to joining IHS Markit, Mr. Muralidharan held posts at ConocoPhillips, Statoil, EY, and Bank of Canada. As a senior economist at Statoil, he oversaw the global macroeconomic forecast and contributed to the global energy market group. He has authored many reports, both in the public and private sectors, and in 2006 won the John Vanderkamp Prize for best public policy paper from the University of Alberta, Department of Economics. Mr. Muralidharan holds undergraduate and graduate degrees from the University of Alberta.

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IHS Markit™

# Major Sources of US Oil Supply: The Challenge of Comparisons

SPECIAL REPORT™

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## About This Report

**Purpose.** This IHS CERA report assesses the challenge of comparing US oil supply in terms of energy security and environmental aspects. Security of supply has long been a policy focus. Now, environmental aspects are also factoring into the discussion on US energy policy. The Canadian oil sands are at the center of this debate. But oil security and environmental comparisons are encumbered by the challenge of collecting accurate data and establishing uniform and relevant metrics among major suppliers. The environmental perspective is focused on factors related to production and does not cover transport issues.

**Context.** This is one in a series of reports from the IHS CERA *Canadian Oil Sands Energy Dialogue 2011.* 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. The 2011 Dialogue program and associated reports cover three oil sands topics:

- **Major Sources of US Oil Supply: The Challenge of Comparisons**
- **Assessing Regulation in the Oil Sands**
- **Life-cycle Greenhouse Gas Emissions Reexamined**

These reports and past Oil Sands Dialogue reports can be downloaded at

www2.cera.com\oilsandsdialogue.

**Methodology.** This report includes multistakeholder input from a focus group meeting held in Calgary, Alberta, on May 4, 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 end of report for list of participants and IHS CERA team).

**Structure.** This report has five major sections, following the Summary of Key Insights:

**Part I: Introduction: What Is Foreign Oil?**

**Part II: Oil Supply: Past, Present, Future.** Where does US oil supply come from today? What are likely future sources of US oil supply?

**Part III: Environmental Aspects of US Oil Supply.** How do the largest sources of US crude oil compare on enviromental aspects? Is it even possible to make these types of comparisons?

**Part IV: Security Aspects of US Oil Supply.** How do the largest sources of US crude oil compare in terms of supply risk?

**Part V: Conclusion.**

We welcome your feedback regarding this IHS CERA report or any aspect of IHS CERA's research, services, studies, and events. Please contact us at info@ihscera.com or +1 800 IHS CARE (from North American locations) or at customer.support@ihs.com or +44 (0) 1344 328 300 (from outside North America).

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# MAJOR SOURCES OF US OIL SUPPLY: THE CHALLENGE OF COMPARISONS

## SUMMARY OF KEY INSIGHTS OF IHS CERA'S ANALYSIS

Security of oil supply has long been a policy focus. Now, environmental aspects of oil are also factored into US energy policy discussions. The Canadian oil sands are at the center of this debate, but objectively making environmental and security comparisons is a challenge.

- **A major challenge in comparing various sources of US oil supply is gathering enough data for meaningful comparisons on environmental aspects as they relate to oil production such as water use, biodiversity impacts, and greenhouse gas (GHG) emissions.** The Canadian oil sands are at the forefront of having meaningful data readily available. If US policy aims to differentiate crudes by environmental aspects, then accurate measurement, verification, and reporting are needed across all sources of oil supply. Data availability is shaped by differing data requirements, regulatory environments, and industry structures across countries. Although a lack of public data does not inherently indicate a lack of concern or care for the environment, it does mean that comparisons are difficult and not even possible in some areas.

- **Environmental comparisons across crude oil supply sources are encumbered by the challenge of establishing uniform and relevant metrics.** Even when data are available, environmental aspects—including water and land use—are not easily compared. For example, the water intensity of oil production is not enough for a proper assessment; local water availability must also be considered. The impact of oil development on a region's biodiversity varies by ecosystem; disturbance in a desert environment is not directly comparable to disturbance in a northern boreal forest, on a prairie, or in the ocean.

- **Canada is a low-risk supplier of oil to the United States.** Security is still an important characteristic of oil supply, as demonstrated by the civil war in Libya and the resulting oil supply disruptions and oil price increases.

- **Supply from the Canadian oil sands has come under considerable scrutiny based on its environmental footprint.** However, to objectively differentiate crude supplies by environmental factors, all major sources of US oil supply must be considered. A significant international data gathering and vetting exercise is needed to for such an exercise. Otherwise, policies that seek to reduce environmental impacts could instead shift emissions to countries or sectors with mischaracterized environmental footprints.

—October 2011



CERA

# PART I: INTRODUCTION

## WHAT IS FOREIGN OIL?

What is "foreign oil"? The term often creates an image of oil imported from a distant land. The United States currently imports over 9 million barrels per day (mbd) of foreign oil. The volume of imports is often portrayed as a national weakness rather than as a means of providing fuel to propel the American economy.* But where does oil imported into the United States come from—and how do these sources differ in terms of geography, perceived security, and environmental characteristics? And how does foreign oil compare to domestically produced oil? Canadian oil is indeed "foreign," but the oil is produced closer to some US consumers than some domestic production—and Canadian supply is connected by pipeline. "Foreign oil"—as well as domestic production—represents a range of geographies and security, economic, and environmental characteristics that are important to the US economy and to US consumers.

Distinctions among sources of US oil supply—and imports in particular—have become an increasingly important matter. US policy debate is already moving in this direction—differentiating crude supplies by life-cycle GHG emissions. Broader environmental factors associated with oil and gas development, including water use and impacts on biodiversity, are also part of the discussion.

Environmental aspects are an emerging issue for imported oil, but security of supply—the reliability and volume of oil supplied to the United States—has long garnered the attention of decision makers. Can one compare different sources of supply based on environmental and security aspects? Can accurate comparisons be made? Are relevant data available and verifiable? Developing appropriate metrics is a big challenge, but one that must be addressed if environmental regulations and security concerns are to be dealt with in a transparent and constructive manner. Otherwise, policies—particularly environmental—could use data and metrics that mischaracterize environmental and security aspects, with the result being counterproductive to the intended policy outcomes.

The purpose of this paper is to inform the discussion on US oil imports by assessing the challenges of comparing the environmental and security aspects of Canadian oil sands—one of the largest sources of US oil imports—to other major sources of current and future US oil supply (see the box "Oil Sands Primer").

This paper has five parts including this introduction:

- Part 1—Introduction: What Is Foreign Oil?
- Part 2—US Oil Supply: Past, Present, Future

*Includes crude oil, condensates, and natural gas liquids (NGLs). Does not include biofuels or refined product imports. Refined product imports are excluded because refined products are not necessarily derived from crude oil produced in-country. For example, US refined imports from Canada are produced mostly from imported oil, so dropping the refined products more clearly shows importance of supply from each country. Source: US Energy Information Agency (EIA).

- Part 3—Environmental Aspects of US Oil Supply
- Part 4—Security Aspects of US Oil Supply
- Part 5—Conclusion

## 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—enough oil to solely supply 25 years of US oil demand.* The oil sands are grains of sand covered with water, bitumen, and clay. The oil in the oil sands is called bitumen, 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.

Oil sands are unique in that they are produced via both surface mining and in-situ thermal processes.

- **Mining.** About 20 percent of currently recoverable oil sands reserves lies close enough to the surface to be mined. In a mining process similar to coal mining, the overburden (primarily soils and vegetation) 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. Slightly less than half of today's production is from mining, and we expect this proportion to be roughly steady through 2030.
- **In-situ thermal processes.** About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered by thermal drilling methods. Thermal methods inject steam into the wellbore to lower the viscosity of the bitumen and allow it to flow through the production well to the surface. Such methods are used in oil fields around the world to recover very heavy oil. Two thermal processes are in wide use in the oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation. SAGD made up about 22 percent of 2010 oil sands production and is expected to grow to more than 40 percent by 2030. Innovations in thermal recovery methods have reduced the amount of energy needed to recover bitumen, and such innovations are likely to continue in the future.

*Assumes average US petroleum demand (excluding biofuels) is 18.7 mbd.

# PART II: OIL SUPPLY: PAST, PRESENT, FUTURE

## US OIL PRODUCTION AND DEMAND TRENDS

The United States has long been among the largest oil-producing countries in the world. During the first century of the oil age—beginning in the 1860s—the United States was the world's largest oil producer and exporter. During World War II the United States accounted for two-thirds of total world oil production and was the most important supplier of oil to the Allied war effort. From the 1950s through the 1970s, oil imports soared as US demand rose well above the level of domestic production. In 1975 the United States imported 4.2 mbd of oil from 18 countries, equivalent to 30 percent of total US oil consumption. US oil imports reached their high point of 10.5 mbd in 2005—equivalent to 60 percent of domestic oil consumption.*

In recent years, US oil production has increased and demand has weakened. From 2008 to 2010, the United States recorded the largest gain in oil production by any single country in the world. On the demand side, the Great Recession and the growing use of biofuels have pushed oil demand down (2009 US petroleum demand was 2.4 mbd lower than in 2005). Still, US oil imports are large; in 2010 oil imports averaged 9.4 mbd—the world's highest and equivalent to 55 percent of total American demand for crude oil, condensates, and NGLs. The United States will remain a significant importer of oil for many years to come.

In this section, we identify the major current and possible future sources of US oil supply. In the coming decades, the US oil supply picture will evolve. Some of today's major suppliers will grow in importance, while others will be unable to maintain current export levels. Moreover, new major US crude oil suppliers are likely to emerge.

## CURRENT SOURCES OF US CRUDE OIL

Today, domestic production is the largest source of US oil supply, and the major suppliers of imported oil are Canada, Mexico, Saudi Arabia, Nigeria, and Venezuela. Canada is by far the largest source of US oil imports. If oil sands are split from the Canadian total—oil sands alone are one of the largest sources of US imports (see Table 1).

## FUTURE MAJOR SOURCES OF US OIL

Globally, numerous oil producers are expected to increase supplies. To identify potential major new suppliers to the United States, we focused on those with the most potential for export growth. We included in our analysis any foreign supplier likely to increase net exports by more than 1 mbd over the next 20 years (including crude oil, condensates, and NGLs). Five suppliers met this requirement: Iraq, Brazil, Saudi Arabia, Kazakhstan, and Canada. For US domestic oil supply, production only was considered—exports are not anticipated. Figure 1 highlights the projected growth for each supplier (green oil barrels in Figure 1).

*All estimates of US imports are on a net basis and include crude, condensates, and NGLs and do not include biofuels or refined product imports, unless otherwise noted.

**Table 1**

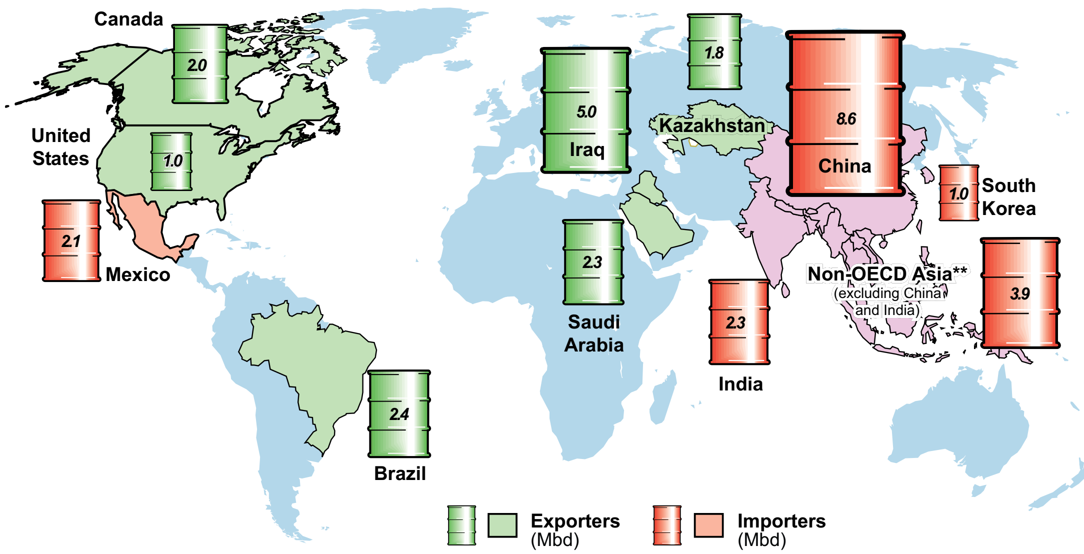
**Breakdown of US Oil Supply, 1975 and 2010***

| 1975 | Thousand Barrels per Day | Percent of Supply | 2010 | Thousand Barrels per Day | Percent of Supply |
|---|---|---|---|---|---|
| Domestic: | 10,008 | 70% | Domestic: | 7,548 | 45% |
| Imports: | | | Imports: | | |
| Nigeria | 746 | 5% | Canada total (including oil sands) | 2,084 | 12% |
| | | | Canadian oil sands only* | 1,100 | 6% |
| Saudi Arabia | 701 | 5% | Mexico | 1,167 | 7% |
| Canada | 600 | 4% | Saudi Arabia | 1,083 | 6% |
| Venezuela | 395 | 3% | Nigeria | 984 | 6% |
| Indonesia | 379 | 3% | Venezuela | 918 | 5% |
| Total imports | 4,217 | 30% | Total imports | 9,392 | 55% |
| Total crude supply (imports + domestic) | 14,225 | 100% | Total crude supply (imports + domestic) | 16,940 | 100% |
| Total number of countries importing crude to United States | 18 | | Total number of countries importing crude to United States | 41 | |

Source: US EIA, Canada NEB, IHS CERA.
*Includes crude, condensates, and NGLs.

**Figure 1**

**Major Sources of Supply and Demand Growth: Projected Growth in Oil Export, Domestic Production, and Import Volumes from 2010 to 2030**
(petroleum only* )




Source: US EIA (historical); IHS CERA (forecast).
*Petroleum only (includes NGLs, condensate, and crude oil).
**Non-OECD Asia excludes China, India, and OECD Asia.
10809-1

US domestic production is already an important pillar of US oil supply, and recent growth in onshore liquids production (crude oil, NGLs, and condensate) is fueling a revival in US output. "Tight oil" production in the United States from plays such as the Bakken play in North Dakota and the Eagle Ford play in south Texas combined with higher NGL output from gas shales is an important source of future liquids supply growth.* By 2030 US production is expected to grow by 1 mbd, and therefore, the United States is considered a major source of new supply growth. It's possible that tight oil production could still exceed our current estimate.

For the foreign suppliers, only part of their growing exports will be US bound, as other countries with rising oil demand will also seek these supplies. To identify growing oil demand centers, we isolated all regions expected to increase net imports by more than 1 mbd over the next 20 years. Five met this requirement; China, non-OECD Asia (excluding China and India), India, South Korea, and Mexico. Figure 1 highlights the growth in imports for these jurisdictions over the next 20 years (see the red oil barrels in Figure 1).

Considering the IHS CERA outlook in Figure 1, both Iraq and Brazil are poised to become new "major" US oil suppliers. Kazakhstan has strong supply growth; however, because of

*New US oil supply is being unlocked by new technology. Oil-bearing formations that were previously too tight for oil to flow to the wellbore are now being produced using horizontal drilling with hydraulic fracturing technology.

its geographic location and the resulting high cost of transportation to the United States compared with other potential markets, it is less likely to ship large volumes of oil to the United States.

In view of this analysis, the largest current and possible future US oil suppliers include US domestic production, Canada, Mexico, Saudi Arabia, Nigeria, Venezuela, Brazil, and Iraq. These eight suppliers are compared on environmental and security aspects in sections III and IV of this report. To learn more about the outlook for each of these suppliers, see the box "Outlook for Current and Future Major Sources of US Oil Supply."

### Outlook for Current and Future Major Sources of US Oil Supply

Considering both current and future sources of US crude oil supply, some suppliers have the potential to further grow exports, while others are projected to remain static or decline.

**Suppliers with potential to grow oil supply to the United States:**

- **US domestic.** Production reached 7.5 mbd in 2010, 45 percent of total US crude oil supply.* Domestic crude oil continues to be the largest source of US oil supply. New supply from tight oil and higher NGL output (from gas shales) are important sources of future liquids supply growth.
- **Canada.** The United States imported over 2 mbd in 2010, 12 percent of total US crude oil supply. Buoyed by growth in production from the Canadian oil sands, supply from Canada is expected to climb by 2 mbd over the next 20 years. However, the growth in US imports from Canada is uncertain, partly because of differing views on the environmental impacts of oil sands development.
- **Saudi Arabia.** The United States imported 1.1 mbd in 2010, 6 percent of total US crude oil supply. The Kingdom has recently expanded productive capacity. However, with the country's growing domestic demand and proximity to Asia, only part of the new supply will be US bound. According to Saudi Aramco reports, Saudi Arabia is already the largest foreign oil supplier to China—providing roughly 1 mbd in 2010.**
- **Iraq.** The United States imported 0.4 mbd in 2010, 2 percent of total US crude oil supply. Iraq has by far the world's greatest potential to grow crude oil supply—IHS CERA estimates that production could grow from 2.6 mbd currently to 8 mbd by 2030. However, Iraq's export growth is expected to mirror its neighbor, Saudi Arabia—a good part of the new supply will likely flow to Asia.
- **Brazil.** The United States imported 0.3 mbd in 2010, 2 percent of total US crude oil supply. In 2010 Brazilian oil production (excluding biofuels) increased by 140,000 barrels per day (bd), and this trend is expected to continue. New offshore developments should propel Brazil into becoming one of the world's largest producers of oil—from producing 2.7 mbd currently to over 5 mbd in 2030. Owing to Brazil's proximity to the US market, a significant part of this future supply is likely to be imported by the United States.

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*All US oil supply mentioned in this box comprises crude oil, condensates and NGLs, and does not include biofuels or refined product imports.
**Saudi Aramco Annual Review, 2010.

**Outlook for Current and Future Major Sources of US Oil Supply (continued)**

**Suppliers with potential to maintain current exports to the United States:**

- **Nigeria.** Nigerian imports were 1 mbd in 2010, 6 percent of total US crude oil supply. The country continues to struggle to maintain production while coping with security challenges (which have caused a sizable portion of supply to be shut in at times over the past decade). New offshore developments should help Nigeria offset declines. The IHS CERA outlook is for relatively flat production capacity over the next 20 years.

**Current suppliers from which exports to the United States are likely to decline:**

- **Venezuela.** The United States imported 0.9 mbd in 2010, 5 percent of total US crude oil supply. Venezuelan oil production has fallen from a peak of 3.2 mbd in 1997 to about 2.5 mbd currently. Investment has not been sufficient, so far, to return to the production levels of the 1990s. Even considering newly awarded exploration blocks and ample oil reserves, exports to the United States are expected to decline, owing to growing domestic oil demand, challenges in executing new oil development projects, and the potential for more of Venezuela's oil to be diverted to Asia.
- **Mexico.** The United States imported 1.2 mbd in 2010, 7 percent of total US crude oil supply. Mexico could become a net importer of oil in the latter part of this decade, however, assuming the current rate of production decline (primarily the result of declines in the Cantarell field), a continued increase in domestic oil demand of approximately 2 percent per year, and minimal investment in developing new oil supplies.

# PART III: ENVIRONMENTAL ASPECTS OF US OIL SUPPLY

## CHALLENGES OF COMPARISIONS

This section addresses the challenges in comparing environmental aspects of oil production in terms of water use, land disturbance, and GHG emissions. In most cases, objective comparisons are difficult because of differences in data requirements among countries.

## ENVIRONMENTAL DATA AVAILABILITY

Data requirements and availability are critical for environmental comparisons among US crude oil suppliers. Although averages attained from rules of thumb or broad assessments can be helpful for general discussion, they are not nearly specific enough to support policy. If US policy aims to differentiate crudes by environmental attributes, more accurate measurement, verification, and reporting of data are needed. A lack of public environmental data does not inherently indicate a lack of concern or care for the environment, but it does mean that comparisons are difficult and perhaps not even possible.

Data reporting requirements and availability vary considerably among jurisdictions—shaped by government policy needs and the approach to oil development. Some governments have, by design, checks and balances between government agencies and the public; these governments have oil and gas regulators that are typically arms-length government agencies, and the availability and transparency of data are an important priority. The approach to oil and gas development also influences data availability. Jurisdictions open to investment by independent companies generally provide more oil and gas data, while countries that rely on national oil companies (NOCs) or joint ventures with NOCs typically have different practices regarding data requirements and public availability because of a different industry structure.

When comparing the data availability among crude oil suppliers, it's critical to recognize this distinction—data availability is driven by industry structure, and regulatory and investment environments.

Of the eight sources of US oil supply included in our analysis, currently only half provide enough environmental data to make meaningful comparisons on environmental aspects of oil production—such as water-use, biodiversity impacts, and GHG emissions from oil developments. Of all the jurisdictions compared, the Canadian oil sands have the highest level of readily available, online data.

- **US domestic.** The United States depends on independent investment to produce its oil and gas reserves. In addition, it has a regulatory system with multiple arms-length government agencies. Consequently, transparency of data is important and environmental data is generally available. The ease of accessing data varies by state, or—for production from federal lands—with the federal regulatory authority. In most cases, basic figures on oil production or injection data are available—often on government Internet sites. However, environmental information—site-specific information on biodiversity changes, detailed groundwater and soil analysis, air monitoring, water consumption and quality, waste disposal, or metrics regarding plant operation or energy consumption—are mostly not available online. Where data are not readily available, a data request can be made to the oil and gas regulator.

- **Canada.** Like the United States, Canada depends on independent investment for oil development and has multiple arms-length government agencies that regulate the oil and gas sector. As a result, data are generally available. Like the United States, the ease of accessing data varies by the type of data requested. For the province of Alberta—home to the Canadian oil sands—detailed oil production, GHG emissions, and injection data are available from the regulator. For in situ operations, the regulator makes detailed site-specific operations data available online. And large oil sands operators voluntarily publish GHG emissions or water consumption data in sustainability reports (and parts of the data in these operator reports are also subject to external review or assurance). For oil sands mining projects, annual environmental reports are publically available at the government library. Compared with other sources of current or possible future US oil supply, the Canadian oil sands has the highest level of readily available environmental data, and online data availability is set to further improve—a new oil sands portal is schedule to launch in 2011. The portal will include environmental data covering production, water use, GHG emissions, disturbed lands, and all current and past environmental approval documents. To access other data, a request must be made to the oil and gas regulator (similar to the US system).

- **Mexico.** Oil is produced by Mexico's NOC, PEMEX. In such cases, data requirements often differ from jurisdictions where private or independent investment is the main driver. Historically, data availability in Mexico has been lower than in the United States and Canada; however, changes in government policy have increased the focus on oil and gas data transparency. In 2008 Mexico created the National Hydrocarbon Commission (CNH), Mexico's first independent upstream oil and gas regulator. One of the mandates of the CNH is to provide the public transparency and access to oil and gas information—including environmental data. IHS CERA received field-level injection data through this process, and other environmental data are also available.

- **Saudi Arabia.** Saudi Arabia's NOC, Saudi Aramco, controls almost all of the Kingdom's oil and gas activities.*As a result of Saudi Arabia's regulatory and investment environment, the needs for data availability are different compared with Canada and the United States. Saudi Aramco provides high-level country aggregate oil and gas production data (as well as information on future plans) in its annual reports. More detailed data, such as field-level production or environmental data, are generally not available to the public.

- **Nigeria.** Nigeria's NOC, the Nigerian National Petroleum Company (NNPC), both regulates and participates in domestic oil developments. NNPC relies on joint ventures with independent companies to develop its oil and gas reserves. In Nigeria, data is

*There is one exception; in 2004, Saudi Aramco started four joint ventures with international oil companies to explore for gas in the country's so-called Empty Quarter. So far, these ventures have not found significant commercial quantities of gas.

less available than Canada and the United States—the regulatory and investment environment requires less data. Until recently, NNPC published field-by-field production figures. However, because of an ongoing reorganization at NNPC, the field-level data are currently not available. Other data can be derived from the reports of operating companies. Typically, environmental data are not available, and, if US policy were to require it for comparisons, a process to supply the information must evolve.

- **Venezuela.** Venezuela's NOC is PDVSA. Although independent companies can participate in the development of Venezuela's oil and gas reserves, participation is limited to joint ventures with PDVSA. In Venezuela data availability is less than in Canada and the United States. In July 2010, for the first time, PDVSA published an environmental and social report—27 pages were dedicated to its environmental performance. The reported data are mostly aggregated at the company or major project level—including air quality, waste production, and water disposal. If more detailed environmental data are required, Venezuela lacks a process to request this information from either the Ministry of the Popular Power for the Environment (the government body responsible for keeping record of all environmental issues in the country) or PDVSA. This process would need to evolve if US policy demanded data.

- **Brazil.** Brazil has a NOC, Petrobras, that also has a degree of private ownership. Generally, Brazil allows for independent investment in developing its oil and gas reserves.* The oil and gas regulator is the Brazilian National Petroleum Agency (ANP). One of ANP's mandates is providing oil and gas data to the public. Owing to Brazil's regulatory and investment environment, generally data are available. ANP posts a considerable amount of data on its website, including field-level environmental and production information. If the data are not available online, the public can contact the regulator to request the information.

- **Iraq.** Iraq's oil ministry controls oil and gas production and development through three operating companies; and the country relies on foreign investment to develop its oil and gas reserves. **Field-level production data are available, but public accessibility to other data on oil and gas developments is limited.

## ENVIRONMENTAL COMPARISONS

This section examines three measures of environmental performance—water use, land disturbance, and GHG emissions. To be sure, this is not a comprehensive list of environmental metrics for oil and gas developments. For instance, effects on local air quality, biodiversity, and groundwater are also important. However, these three serve as illustrative case studies, demonstrating the level of data available and the complexity of comparisons.

### Comparing Water Use

To compare water use in oil production more easily from different supply sources, there is a desire to create simple, comparative metrics. Water intensity—the amount of water consumed

* The only exception is the presalt region; here independent companies must partner with Petrobras.
** One exception to Iraq's oil ministry control is the Kurdish area in the north.

per barrel of oil produced—is the most frequent comparison (see the box "How Does Water Use in Oil Sands Compare with Other Fuel Types?" for examples of water-use intensity). Although water intensity metrics are appealing, they should be used with caution—a proper assessment must consider the local context. Comparing data across countries or even within countries is unlikely to be a meaningful exercise without taking into account the local context of water demand and supply. For each oil source, it is critical to consider—is there sufficient water in the region to meet industry, agricultural, and domestic needs without causing environmental damage?

Water quality is also important. For example, is consuming a barrel of nonpotable, saline, groundwater—referred to as brackish water—equal to consuming a barrel of fresh water? The answer to the quality question is also a local issue. In a location with ample supplies of fresh water, using large volumes of brackish water could be inconsequential. However, in an environment with limited fresh water supplies, brackish water could be a valuable resource.

Comparing only water consumption data across the eight oil suppliers in this analysis and assuming a significant data-gathering and vetting exercise were conducted, water intensity could be calculated for the United States, Canada, Mexico, and Brazil (see Table 2). Other major sources of US oil supply do not provide enough public information for this calculation. The Canadian oil sands supply (through operator published sustainability reports and online data from the regulator) is the only source with sufficient online data to gauge water intensity.

## Comparing Land Disturbance

The land disturbance from oil developments is often compared using a "percent of disturbed land" metric—the fraction of land affected by the oil and gas development compared with the total land area. With the advent of easily accessible global satellite images, the land disturbance from an oil and gas development anywhere in the world can be estimated—therefore, data availability in a particular jurisdiction is no longer a limitation. However, this type of metric can still be uncertain:

- **Accuracy.** Measurement by this method (using publicly available satellite images) can be subjective. The data are most often of low granularity, and there is human judgment involved in determining the metric—for instance, drawing the boundary around the parameter of the oil and gas development and defining what land is actually disturbed. In comparing oil developments, a consistent methodology must be applied.

- **Dissimilar land types.** A simple metric, such as the percent of land disturbed, does not consider the predevelopment land use and biodiversity. The natural state of land in the oil sands region is boreal forest. Evergreen trees dominate the landscape, and 30 to 40 percent of the area is wetlands. The forest is home to many animals, including caribou, bear, wolves, moose, deer, and countless types of birds. This is different from a desert environment in the Middle East where much of that region's crude supply originates. In the desert, plant and animal life is more dispersed and therefore, in absolute terms, desert oil and gas developments will have an impact on less biota. However, as the desert ecosystem is fragile, this lower threshold of disturbance to plants and animals could still be consequential.

- **Volume of energy produced.** A simple metric, such as percent of land disturbed, does not account for energy intensity of the disturbance. Oil wells are not all equal in their ability to produce oil. For example, the average oil sands SAGD well pair produces over 570 bd, while an above-average onshore conventional oil well produces between 50 to 100 bd; although the percentage of land disturbed for most conventional developments is lower, in situ oil sands production has less of an impact per barrel of oil produced (see the box "How Much Land Is Used for Oil Sands Development?").

- **Not directly comparable for offshore developments**. A land disturbance metric is not relevant for comparisons with offshore developments. Yet both offshore and onshore developments can have impacts on biodiversity.

## Comparing Life-cycle GHG Emissions of Crude Oils

The life-cycle (also known as "well-to-wheels") emissions for a petroleum fuel cover all GHG emissions from the production, processing, and transportation through to the final consumption of the fuel. Unlike water and land, GHG emissions are a global, not local, issue. Regardless of where the GHG is emitted, it has the same effect on the environment.

Distinctions among GHG emissions associated with US oil supply—and imports in particular—have become an increasingly important topic. California's Low Carbon Fuel Standard (LCFS) could restrict future imports of crudes with high carbon intensities—including the Canadian

### How Does Water Use in Oil Sands Compare with Other Fuel Types?

Although oil sands projects have been criticized for being water intensive, they are not alone in requiring significant amounts of water for production—many types of energy production use a great deal of water. Figure 2 depicts the water use of several liquid fuel and electricity production methods on an equivalent energy basis.

Currently, net water use in oil sands production averages about four barrels of fresh water per barrel of bitumen for mining operations and 0.7 barrels of water per barrel of bitumen produced from in situ operations.* For in situ operations, almost half of the water is sourced from brackish water. Conventionally produced oil can use up to 1.5 barrels of water per barrel of oil produced, while water use for enhanced oil recovery ranges from similar to oil sands to significantly higher.

Oil alternatives can also be water intensive (see Figure 2). Ethanol produced from irrigated crops such as corn can use more than 500 barrels of water per barrel of ethanol, and coal-to-liquids can use 10 barrels of water per barrel of finished product.**

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*For mining operations, includes water from the Athabasca River and water collected from site runoff and mine dewatering.
**Sources: US Department of Energy (DOE), December 2006; Argonne National Laboratory, Energy Systems Division, *Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline,* 2011 Update; and IHS CERA.

**Table 2**

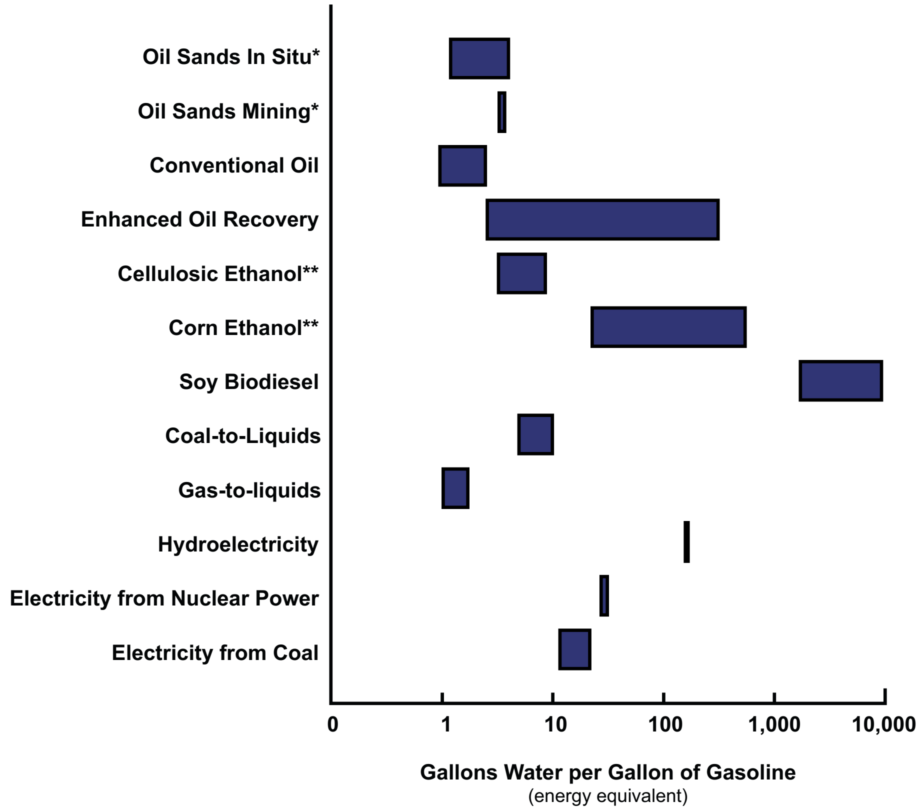
**Water Consumption Data Availablity and Source**

| | Water Consumption Data Availability | Can Project-level Water Intensity Metric Be Calculated? | Water Source for Oil Production |
|---|---|---|---|
| US Domestic | Publically available by request, in most states not online | ✔ | Source of water varies by development type: ocean water, fresh and brackish groundwater |
| Canadian Oil Sands—Mining | Publically available and online | ✔ | Fresh surface water |
| Canadian Oil Sands—SAGD | Publically available and online | ✔ | Fresh and brackish groundwater |
| Canadian Oil Sands—CSS | Publically available and online | ✔ | Fresh surface water, fresh and brackish groundwater |
| Mexico | Publically available by request (not available online) | ✔ | Source of water varies by development type: ocean water, fresh and brackish groundwater |
| Saudi Arabia | Limited data | | Groundwater is mostly brackish, and ocean water |
| Nigeria | Limited data | | Onshore water injection is not typical; some offshore developments use ocean water |
| Venezuela | Recent enviroment and sustainblity report provides country-level data, project level data is not available | | Limited data, mostly fresh surface water |
| Brazil | Publically available by request (not available online) | ✔ | Water injection is not typical; some offshore developments use ocean water |
| Iraq | Limited data | | Few fields use water injection; some new southern developments plan to use sea water |

Source: IHS CERA.

**Figure 2**

**Life-cycle Water Intensity of Various Energy Sources**




Sources: US Department of Energy, *Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water,* December 2006.
*Source: IHS CERA, based on operator reports. Mining values are net fresh water river withdrawals only. Added 1 barrel to upstream numbers to account for refining.
**Source: Argonne National Laboratory, Energy Systems Division, *Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline, 2011 Update.*
10809-3

oil sands.*A high-carbon-intensity crude produces GHG emissions that are above a certain standard or average. In addition to California, several other US states are considering a LCFS. Together the states implementing or considering an LCFS represent 50 percent of all of the gasoline consumed in the United States.

In September 2010 IHS CERA published the Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right,* which puts 13 publicly available life-cycle

*California's LCFS went into effect in 2010. The law requires average transportation fuel consumed to have 10 percent lower life-cycle GHG emissions by 2020 compared with 2010. Higher-carbon crudes (like the Canadian oil sands) will struggle to meet this mandate; they require greater volumes of scarce low-carbon fuels to offset their higher carbon intensities. The California LCFS does not treat all high-carbon crudes equal—some California domestic production has a carbon footprint similar to other high-carbon crudes, but this supply is grandfathered under the LCFS. See the IHS CERA Special Report *Oil Sands, Greenhouse Gasses, and US Oil Supply: Getting the Numbers Right*.

**How Much Land Is Used for Oil Sands Development?**

Oil sands land use concerns vary by oil sands production method:

- **Oil sands production from mining.** While an area is being mined, 100 percent of the land is disturbed. After the area is mined out, the land must be reclaimed. The definition of reclaimed land and the pace of reclamation are open questions for many who want the land restored as quickly as possible to its predisturbance state.

- **Oil sands production from in situ.** IHS CERA estimates that the disturbed area of a SAGD project averages about 7 to 15 percent of the lease. This compares favorably to mining and is generally—but not always—higher than conventional oil development; in comparison, the land disturbance from five conventional oil and gas jurisdictions ranged from 1 to 17 percent of the lease.*

*IHS CERA compared a group of onshore developments in Mexico, Saudi Arabia, Nigeria, Venezuela, and Brazil using satellite images.

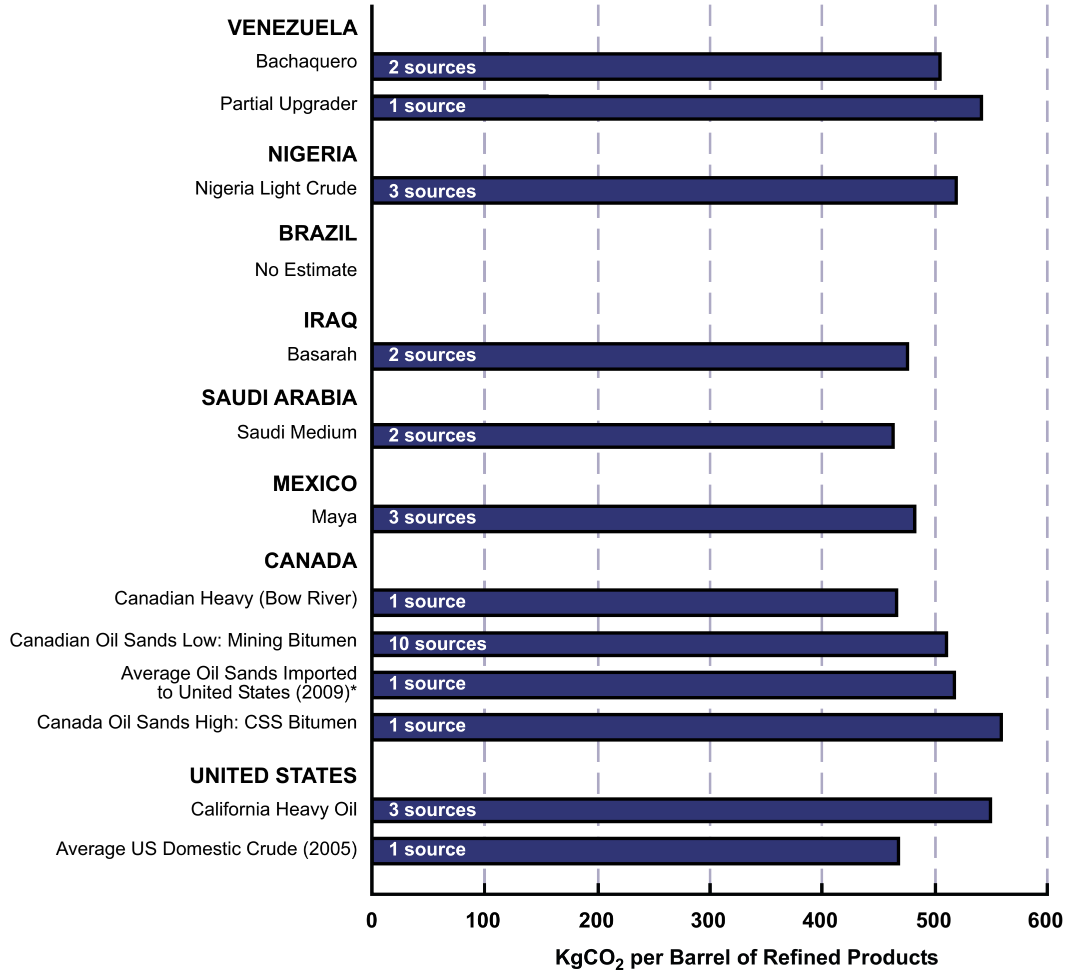
studies into a consistent framework with the goal of providing a broader comparison than any single study (to download this report, please visit www2.cera.com\oilsandsdialogue).* For most countries, only limited estimates of the GHG emissions from oil production are available. For instance, the GHG emissions from Venezuelan partial upgrading is based on one data source—a dated study with limited information on assumptions or inputs (see Figure 3).** For example, studies for Canada Bow River, for oil sands production using the CCS method, and for Middle East heavy oil also have limited sources. Further, even if multiple studies exist, they are based on estimates. For many sources of oil supply, getting accurate industrywide or even field-level data describing energy consumption, production, or injection rates is not possible—and a very significant international data-gathering and vetting exercise would need to be put in place to do so (see the Environmental Data Availability section, above). The challenge of accurately estimating life-cycle GHG emissions is further reflected in the wide range of results across the 13 studies analyzed by IHS CERA. Estimates of well–to–retail tank emissions for specific crudes varied by as much as 45 percent (or 10 percent on a life-cycle or well-to-wheels basis). Although estimates for GHG emissions for various crude sources exist (and are highlighted here), they are best estimates—helpful for general discussion, but not nearly specific enough to support policy.

*Original studies included within the IHS CERA analysis are Jacobs Consultancy, *Life Cycle Assessment Comparison of North American and Imported Crudes* (July 2009); TIAX LCC, *Comparison of North American and Imported Crude Oil Life-cycle GHG Emissions* (July 2009); DOE/National Energy Technical Laboratory, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels* (November 2008); McCann and Associates, *Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles* (November 2001); RAND Corporation, *Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs* (2008); National Energy Board, *Canadian Oil Sands: Opportunities and Challenges* (2006); Canadian Association of Petroleum Producers, *Environmental Challenges and Progress in Canada's Oil Sands* (2008); GREET Version 1.8b, (September 2008); *GHGenius 2007 Crude Oil Production Update Version 3.8, Syncrude 2009/10 Sustainability Report; Shell Sustainability Report* (2006); and IHS CERA data.

**The GHG emissions estimate for oil supply from the Venezuelan Partial Upgrader was published in 2007 and was based on a partially completed 2001 study by McCann Associates Ltd. Limited data are provided for the Venezuelan project; the paper states that the study was based on a model of the Petro Zuata project with data provided by an undisclosed early participant in the research. Other GHG estimates also have limited sources.

**Figure 3**

**Well-to-wheels GHG Emissions from Crude Oil**




Source: IHS CERA.
Data Sources:
Venezuela: Bachaquero—Jacobs-AERI (2009); TIAX-AERI (2009).
Venezuela: Partial Upgrader—McCann (2007).
Nigeria: Nigeria Light Crude—McCann (2007); Jacobs-AERI (2009); TIAX-AERI (2009).
Iraq: Basarah—Jacobs-AERI (2009); TIAX-AERI (2009).
Saudi Arabia: Saudi Medium—DOE/NETL (2008); Jacobs-AERI (2009).
Mexico: Maya—DOE NETL (2008); Jacobs-AERI (2009); TIAX-AERI (2009).
Canada: Canadian Heavy (Bow River)—TIAX-AERI (2009).
Canada: Canadian Oil Sands Low: Mining Bitumen—TIAX-AERI (2009); McCann (2007); GREET; GHGenius; RAND (2008); Jacobs-AERI (2009); Syncrude (2009/10); Shell (2006): NEG (2008): CAPP (2008).
Canada: Average Oil Sands Imported to United States (2009)—.
Canada: Canada Oil Sands High: CSS Bitumen—TIAX-AERI (2009) (assumes SOR of 3.35).
United States: California Heavy Oil—Jacobs-AERI (2009); TIAX-AERI (2009); IHS CERA.
United States: Average US Domestic Crude (2005)—DOE/NETL (2008).
10809-2

# PART IV: SECURITY ASPECTS: US OIL SUPPLY

## FACTORS SHAPING OIL SUPPLY SECURITY

From the perspective of an oil consumer, oil security is about adequate and reliable supply. Although oil supply security is shaped by many factors, resource endowment, the historical performance record, and perception of political stability are important.

First and most importantly, a secure supplier must be sufficiently endowed with oil reserves. Although large endowments of oil resources are a function of geological forces, producing the oil reliably is not. The potential for stable oil production is shaped by many factors—type of resource, geographic location, technology, and the country's political and fiscal environment, to name a few.

Among today's major suppliers of US oil, both Mexico and Venezuela have ample reserves, yet they are struggling to maintain supply. In the past five years, Venezuela's production has dropped 500,000 bd, and Mexico's has fallen by 600,000 bd. In large part, these declines are due to the political and investment climate. In Venezuela, past expropriation of assets and changes to fiscal terms have contributed to reduced oil production. In Mexico, a lack of investment and limited access to the newest technology have been factors.

The historical performance record—the reliability of supply—is another concern. Because of security challenges, Nigeria has struggled to maintain its production. Militant groups have repeatedly shut-in oil developments there—often taking hostages. Moving production offshore was thought to reduce this risk; however, militants have disrupted offshore production as well—although to a much lower degree than onshore.

To analyze the relative security associated with major current and future sources of US oil supply, we used the IHS Petroleum Economics and Policy Solutions (PEPS) service. In addition to providing regulatory, legislative, economic, and commercial data, PEPS provides political risk rankings for 125 countries. The IHS political risk index considers the political, socioeconomic, and commercial aspects for each country and is an indication of the relative risk of future supply.*

This supply risk assessment is an effort to assess and rank countries based on the current situation at a particular point in time. This is simply a snapshot, and as demonstrated by the Arab Spring, an unexpected development can set in motion events that can alter the political landscape of a region. Moreover, it is clear that the length of time a government has maintained power or the current level of risks is not necessarily an indication of the future. The nature and level of political risk in any particular country can change quickly. Indeed, there is uncertainty in future oil supply for all countries compared.

Considering the eight oil suppliers compared in this paper, low-risk suppliers include Brazil, Canada, Saudi Arabia, and the United States. All have ample reserves, and stable

* Political risks include factors such as potential for wars, unrest, internal violence, and regime instability. Socioeconomic risks are shaped by factors including economic stability, domestic energy demand and supply, and environmental opposition to oil and gas development. Commercial factors include stability of the contract and fiscal terms, openness for foreign investment, and stability of investment.

governments, and have historically proven to be reliable sources of oil supply. Medium-risk suppliers include Mexico and Venezuela. Although the countries have ample reserves of oil, both have limited access to foreign capital and have struggled to increase their oil supplies. Other risks include the potential for security issues (Mexico) and political instability (Venezuela). Higher-risk suppliers include Iraq and Nigeria. For both countries, lack of security continues to create supply risk, adding uncertainty to the amount of oil that can ultimately be produced.

## PART V: CONCLUSION

Security of oil supply has long been a US policy concern. Security of supply is still important, as demonstrated by oil supply disruptions associated with the civil war in Libya. History illustrates the affects of oil shocks. In each past oil shock, panic and expectations of conflict have driven oil price increases, with negative consequences to the United States and the global economy. Canada is a low risk source of oil supply. Oil is a key element of deep economic links between the United States and Canada. Increasing supply from Canada offers the United States greater oil supply security.

Now, environmental aspects of oil are also factored into the US energy policy discussion. In terms of environmental comparisons—such as GHG emissions, water use, and land use—environmental data, availability, and government needs differ across jurisdictions making comparisons challenging. Comparing major sources of US oil supply, Canadian oil sands are at the forefront of readily available data. A second challenge with environmental comparisons is establishing uniform and relevant metrics. Even when data are available, environmental aspects—including water and land use—are often not comparable.

Supply from the Canadian oil sands has come under considerable scrutiny based on its environmental footprint. However, to differentiate crude oils by environmental factors objectively, all major sources of oil must be considered using accurate and verifiable data. Otherwise, policies that seek to reduce the environmental footprint could instead shift emissions to countries or sectors with mischaracterized environmental footprints. ■

## REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Calgary, Alberta (May 4, 2011), providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to US oil supply sources. 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.

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Canada West Foundation
Canadian Association of Petroleum Producers—CAPP
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Canadian Oil Sands Limited
Cenovus Energy Inc.
Chevron Canada Resources
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Nexen Inc.
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TransCanada Corporation
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## IHS CERA TEAM

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Mr. Burkhard also leads the IHS CERA Global Energy Scenarios, which combines energy, economic, and security expertise across the IHS Insight businesses into a comprehensive, scenarios-based framework for assessing and projecting global and regional energy market and industry dynamics. Previously he led *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030,* which encompassed the oil, gas, and electricity sectors. He was also the director of the IHS CERA Multiclient Study *Potential versus Reality: West African Oil and Gas to 2020.* He is the coauthor of IHS CERA's respected *World Oil Watch,* which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Mr. Burkhard has also testified several times before US Congress on oil and energy issues. Before joining IHS CERA Mr. Burkhard was a member of the United States Peace Corps in Niger, West Africa. He directed infrastructure projects to improve water availability and credit facilities. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

**Jackie Forrest, IHS CERA Director, Global Oil,** leads the research effort for the IHS CERA Oil Sands Energy Dialogue. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products. She actively monitors emerging strategic trends related to oil sands including capital projects, economics, policy, environment, and markets. She is the author of several IHS CERA Private Reports, including an investigation of US heavy crude supply and 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 the team that developed the North American unconventional oil outlooks and recommendations the 2011 NPC report *Prudent Development of Natural Gas & Oil Resources*—including 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. 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. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**Terry Hallmark, IHS Director of Political Risk and Policy Assessment.** Dr. Hallmark has served as a consultant to major oil and service companies, financial institutions and governmental agencies. He has also lectured extensively on political risk assessment and has written on the subject for the *Petroleum Economist, Offshore* magazine, the *American Oil and Gas Reporter,* and the *Oil & Gas Law and Taxation Review.* He has also contributed to The Handbook of Country and Political Risk Analysis, which provides an overview of political risk assessment methodologies. Dr. Hallmark holds both a bachelor's and a master's degree from the University of Houston, and a doctorate from the School of Politics and Economics at Claremont Graduate University. For the past 22 years, he has been an adjunct faculty member in the University of Houston's Department of Political Science, and more recently has joined the University's Honors College, where he specializes in political philosophy, American political thought, and American foreign policy.

# The continued convergence of media & technology

Advancing technologies such as Blockchain, Virtual Reality, 5G and the rise of Online Programming are changing the way media is consumed.

The media industry needs to evolve to survive.

# How will Blockchain impact the media industry?

Blockchain is a distributed digital ledger technology which is used to record various types of transactions. In addition to being distributed, blockchain also utilizes cryptography and timestamps to provide a permanent record of interactions.

As the underlying technology enabling Bitcoin, blockchain is currently being considered for a wide range of applications across many vertical markets, such as telecoms, music, games and advertising.

To date blockchain is not yet part of mainstream technology, however investment is increasing from big technology platforms such as Amazon and Alphabet/Google, as well as by a wide range of enterprise, consumer, media, and e-commerce firms.

And while possessing potential application across multiple industries, viable use cases and effective business models for blockchain remain nascent or limited at this point.

For many, the commercial potential of blockchain is still unclear, and blockchain services face challenges ahead of commercial deployment—including hurdles with local regulation and many sensitive questions involving privacy vs. transparency, speed of execution, and computational requirements.

Overall, however, the timeline for blockchain disruption and transformation will vary greatly, depending on industry readiness and as companies continue to experiment with the technology.

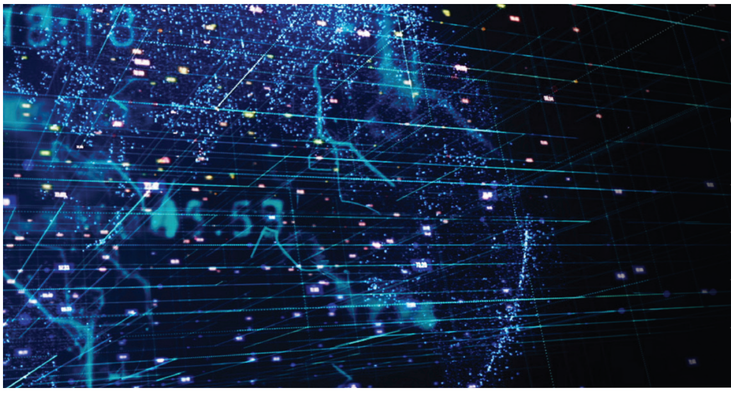
# What is blockchain?

## Blockchain or Distributed Ledger Technology [DLT] is:

Essentially a decentralised ledger or store of records that enables the transaction and execution of smart contracts and decentralized applications.

## Blockchain is not:

Bitcoin or cryptocurrency – these are assets that serve decentralised applications and which are traded using blockchain technology

## Blockchain records are designed to be:

- Secure
- Transparent
- Immutable [as possible]
- Decentralised

## Blockchains can be:

- Public/ permission less – anybody can participate e.g. Bitcoin, Ethereum
- Private/ permissioned - serving a company or group specific need
- Hybrid

# Blockchain Use Cases

## **Music:** Using blockchain for licensing and payments

### Challenges:

- Creating marketplaces for digital items & second hand digital transactions
- Enabling P2P communities
- Revenue distribution and shares – developer and publisher contracts

### Blockchain solutions and companies:

- **GameCredits** – has partnered with Unity Technologies to integrate its blockchain technology in Unity's game engine to enable its GPlay in-game credit marketplace and publish to the GPlay store
- **EverdreamSoft and Channel 4** -launched trading card game integrating blockchain technology
- **Ownage** – blockchain market place for digital games and virtual item trading

### Potential:

- **Scale** – integrating with Unity is a strong move to drive developer adoption, but marketplaces and alternative stores could be limited by scale of larger consumer platforms
- **Regulation** – cryptocurrency-based transactions may be impacted by regulation regarding licensing and content distribution.
- **Adoption**: industry adoption has strong potential given technology positioning
- **Use cases** second-hand marketplace use case appeal may be relatively limited

# Blockchain Use Case : Advertising

## Using blockchain to improve transparency, measurement and attribution Advertising

### Challenges:

- Measurement and attribution – combating ad fraud
- Data security – user and company data for personalisation and targeting
- Efficiency – managing revenue flow across complex ecosystem

### Blockchain solutions and companies:

- **Comcast Advanced Advertising Group** – Blockchain Insights Platform
- **Nasdaq** - launched a blockchain-based trade exchange for guaranteeing advertising contracts in Q1 2017.
- **MetaX and the Data & Marketing Association** – launched adChain in Q2 2017, using Ethereum to tag when ad creative is viewed

### Potential:

- **Adoption** is still very limited – but there are still clear challenges that blockchain tech can help solve
- **Speed** is an issue – the compute power for ad-delivery is far below what is necessary for real time bidding
- **Use cases** may also be limited, for example high value video delivery doesn't rely on a secondary market so smart contracts aren't necessary


# Blockchain Use Case: Games

## Digital content market places and P2P communities

### Challenges:

- Creating marketplaces for digital items & second hand digital transactions
- Enabling P2P communities
- Revenue distribution and shares – developer and publisher contracts

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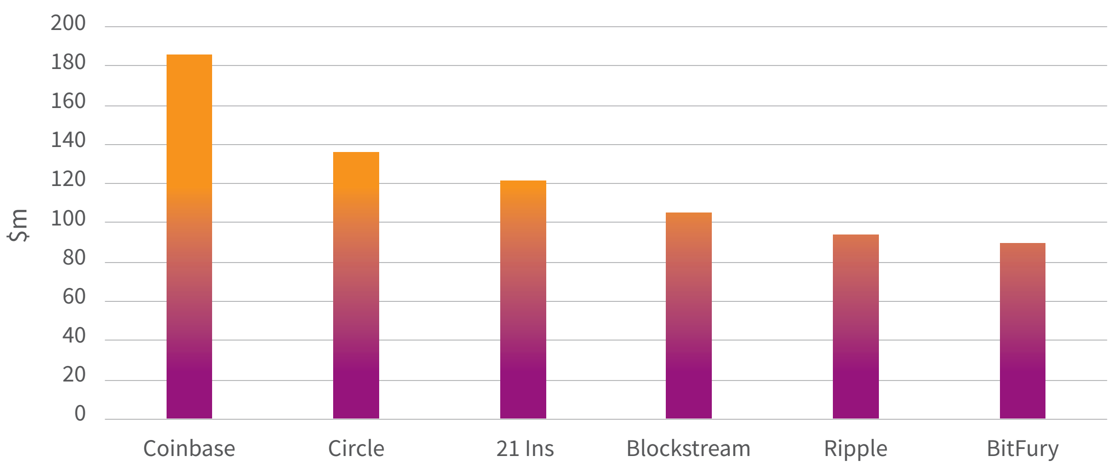
- **Use cases** second-hand marketplace use case appeal may be relatively limited

# Blockchain attracts significant funding from venture capital firms

- **Interest in blockchain technology has led to the establishment of dedicated blockchain funds including venture capital firms such Digital Currency Group and Blockchain Capital, which have heavily invested in blockchain and bitcoin startup companies.**
- Of the blockchain/bitcoin companies tracked by IHS Markit, Coinbase has raised the most funding from 2015-2017.
- The top companies that have raised the most funding from investors include: Coinbase, Circle, 21 Inc, Ripple, BitFury, and Blockstream. These companies are mainly focused on bitcoin and wallet services and have raised more than $700m combined

## Select blockchain/bitcoin funding by company 2015-2017 ($m)




## Despite its clear promise, blockchain technology is not a panacea – existing solutions may still be best

### Immutability

Immutability has been promoted as one of the advantages of blockchain, as it ensures the security of the data and prevent fraud and corruption.

### But…

It also presents challenges when a record needs to be removed or rewritten.

### Smartcontract

Smart contracts are one of the benefits that blockchain offers. These are contract clauses, written in code and place onto the blockchain. When a trigger event occurs, they will be activated automatically.

### But…

These still need legal expertise. Clear regulatory frameworks need to be defined. Otherwise, smart contract can make things more complicated.

### Speed issues

Blockchain will improve the efficiency of operations through streamlining processes and transparency.

### But…

Blockchain has its own limits. The need to update every node means that updates are slowed as the network grows and alternatives can be much faster

### Private or public

Companies can choose to develop a public or private blockchain based on their business model.

### But…

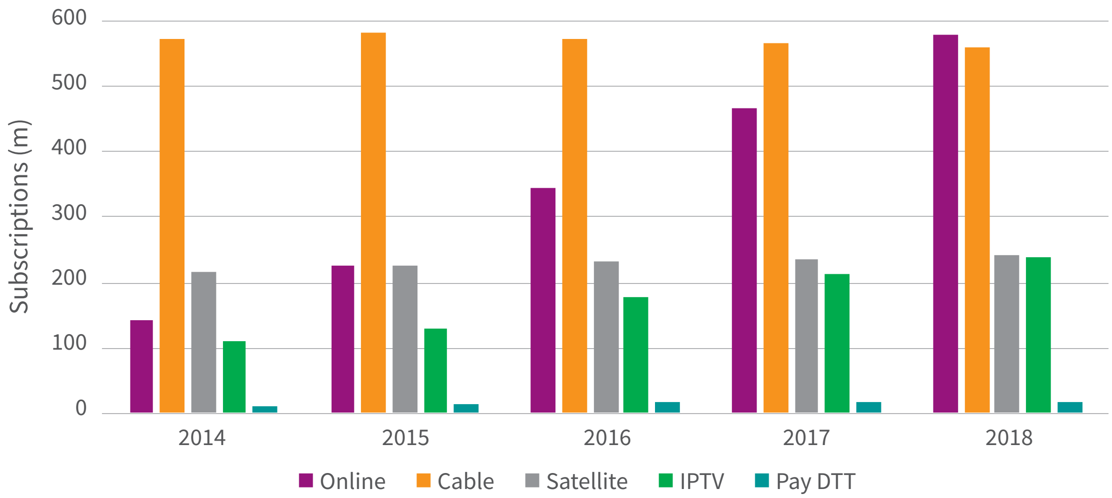
Sometimes, one supplier can be involved in multiple supply chains. Interoperable blockchains are needed to enable transactions across public and private blockchains.

# The virtualisation of subscription TV

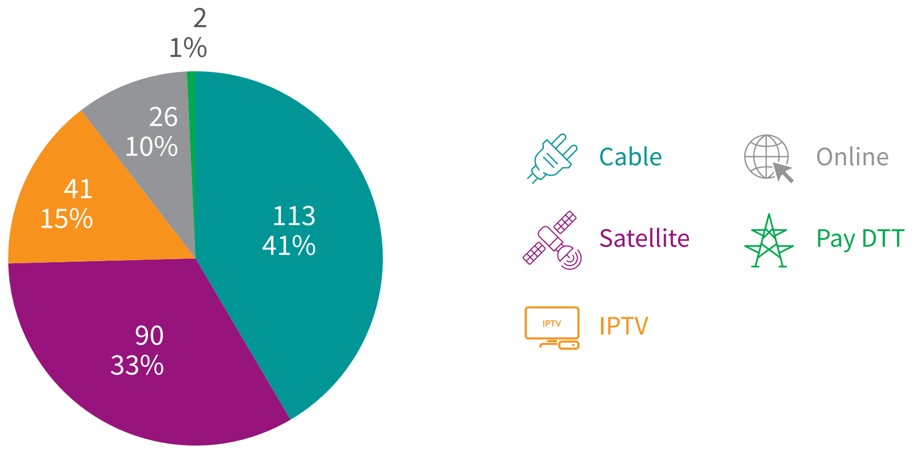
## The Virtualisation of Subscription TV – what does this mean for traditional pay TV?

- The TV & video landscape is changing fast – IHS Markit forecasts that by the end of 2018, more video subscriptions will be delivered online via the open Internet than any traditional pay TV technology
- However, the vast majority of subscription revenues continue to be generated by cable, satellite and IPTV, as low-cost OTT services – particularly Netflix's channel-like offering – in many cases supplement traditional pay TV subscriptions

### Global Pay TV and Online Video Subscriptions by Platform



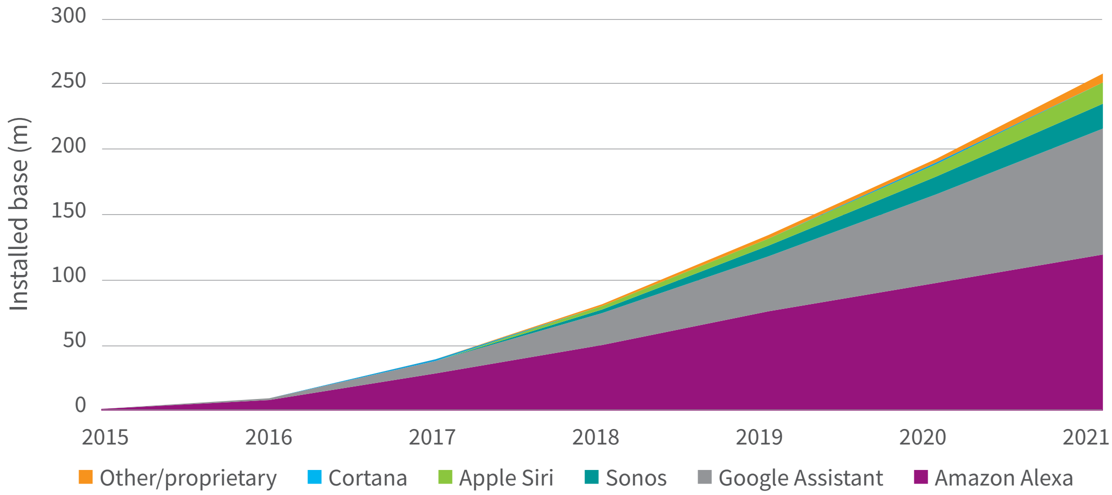

### Global Subscription TV and Video Revenues by Platform 2017 ($bn)

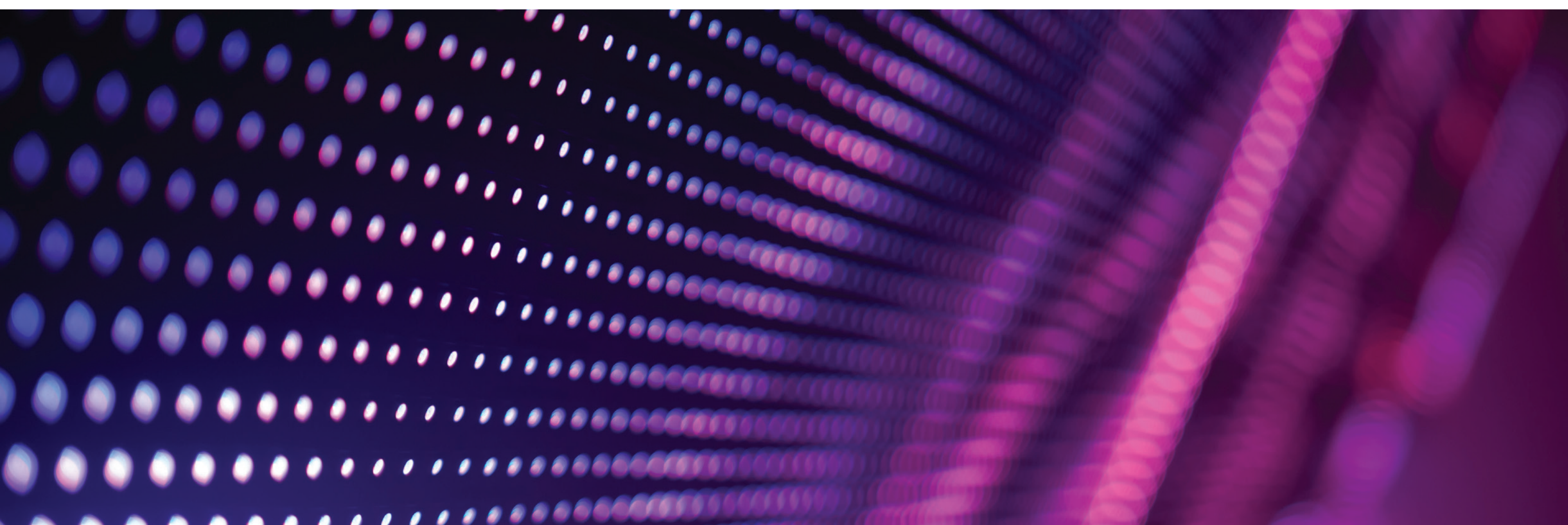


# Adapting and improving pay TV services to leverage the evolving device ecosystem

- For pay TV operators, personalised recommendations and intuitive search and navigation across live and on-demand TV are central to providing better content discovery – voice control is an important emerging differentiator
- In order to give their customers the best voice-based user-experience, operators may need to work with third-party providers of digital assistants and smart speakers, which will become an important part of many pay TV homes

## Global: Smart speaker installed base by assistant



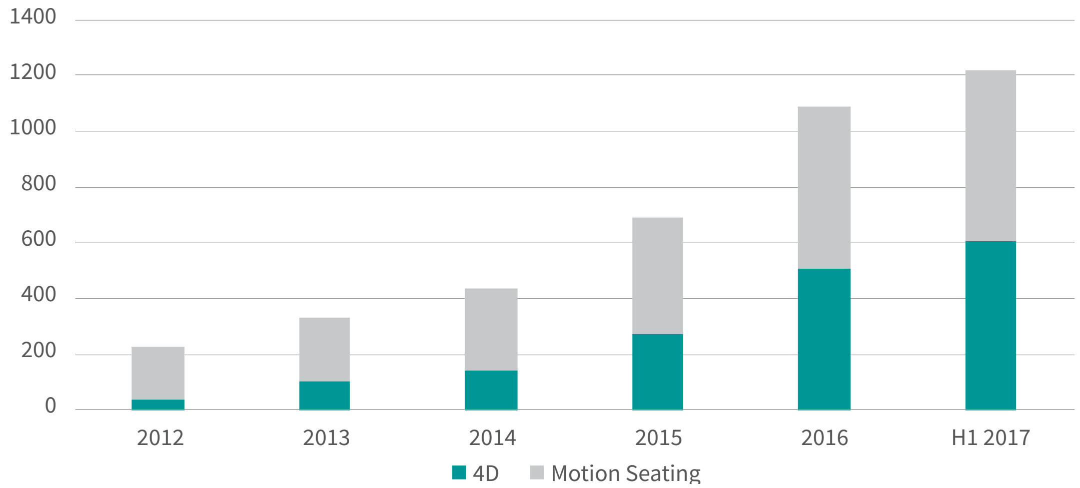



# The evolution of cinema

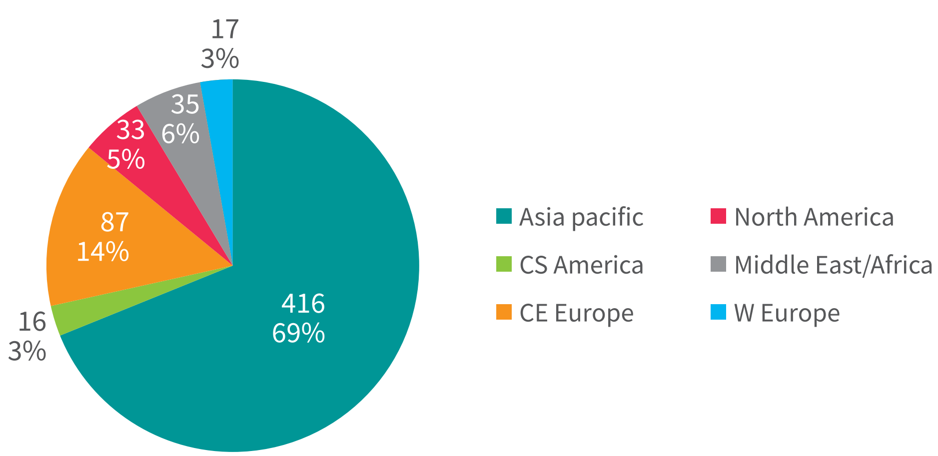
## 4D and Immersive motion seating is one of the fastest growing areas of cinema exhibition

- The total of IMS and extreme 4D screens has increased almost three fold since 2014 reaching 1,219 screens
- China quadrupled its 4D screen base in the 12 months to H1 2017 and now accounts for almost 50% of the world's 4D screen base

### 4D and IMS screens




### 4D screens by region

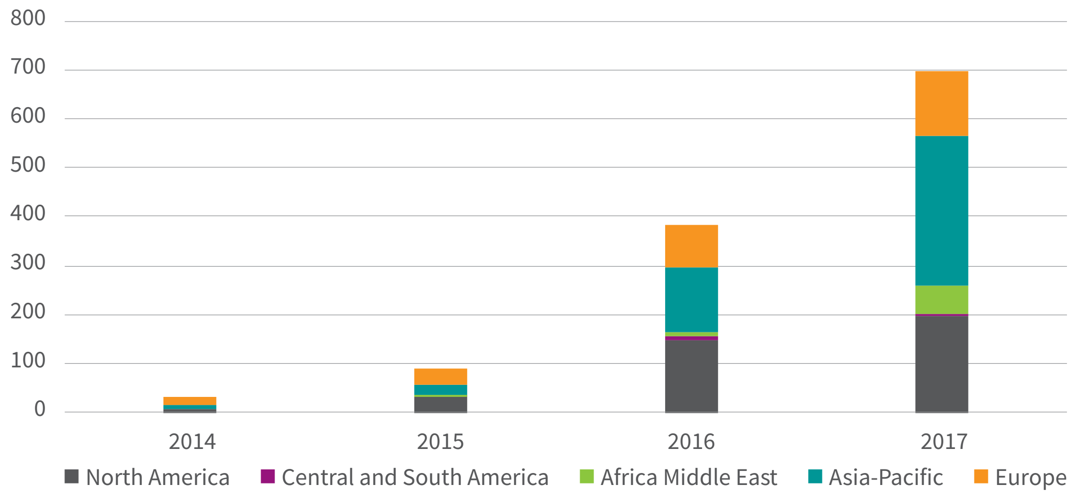


# RGB laser on the rise: New high for net RGB laser installations in cinemas in 2017

– Exhibitors are seeking out the benefits of RGB with 315 new RGB screens installed in for a total of 699 worldwide in 2017, an annual increase of 80% and up seven fold from 89 RGB screens active in 2015

– Brighter 3D and HDR are major drivers for replacement of first generation digital projectors and are increasingly being adopted by premium (PLF) screens. Global PLF brands, Imax and Dolby Cinema together accounted for 25% of the global RGB base

## Growth story for RGB screens




# Programming investment continues to increase

## Disney leads worldwide programming expenditure top ten

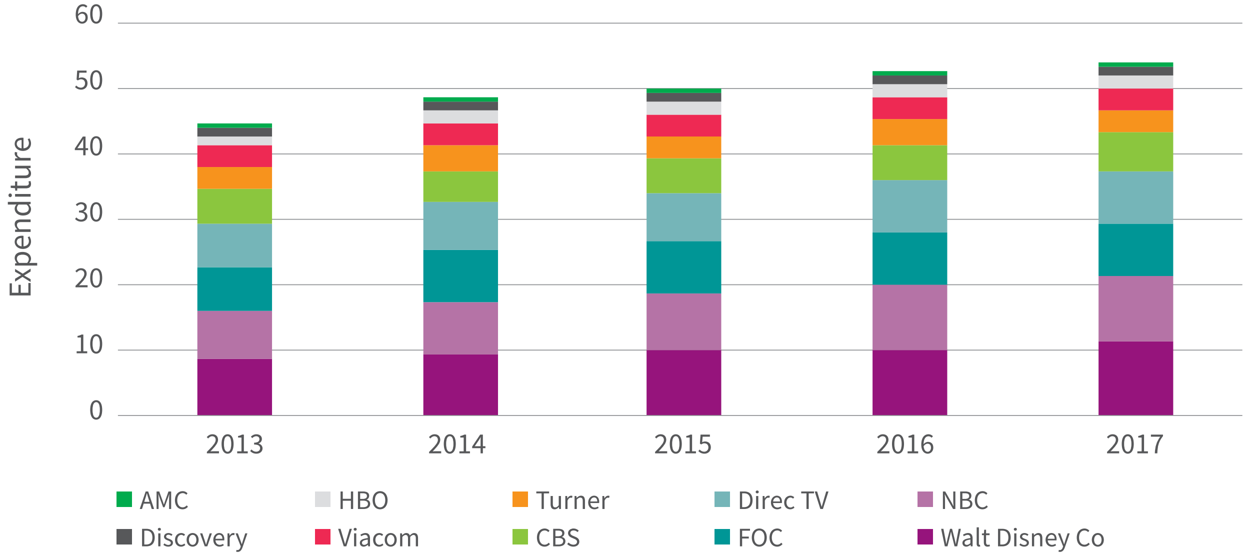
- We estimate that top ten US groups invested $54.2 billion in programming in 2017, $9.9 billion more than the $44.3 billion invested in 2013. There was a 3% year-on-year increase in expenditure from $52.7 billion in 2016 to $54.2 billion in 2017.

- Despite changes in the US TV market – falling audiences for free-to-air channels and cord-cutting in the pay TV sector – programming investment continues to increase, driven by primacy of original scripted programming on broadcast and cable networks and the rising cost of rights for premium sports events.

- Across its ABC free-to-air division and its cable networks (ESPN, Disney Channel, Freeform), Walt Disney was the leading investor in programming in 2017 with $11.5 billion. Fox was second with $8.4 billion, while DirecTV, now owned by AT&T, invested $7.9 billion.

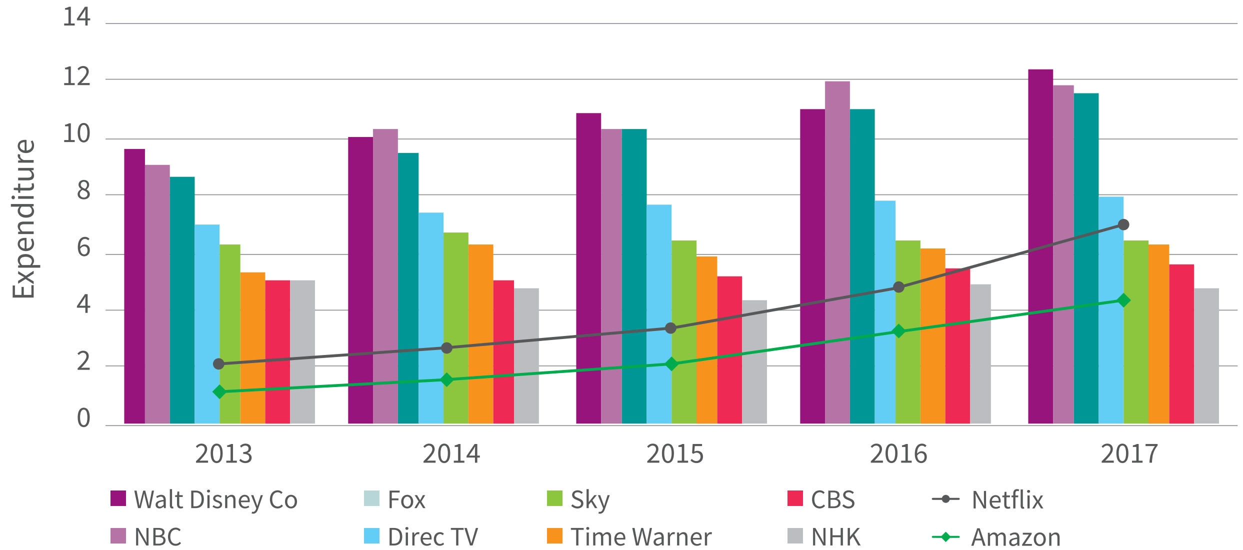
- At a worldwide level, both online platforms have burst into the list of the top ten groups in the last five years. In 2017, Netflix was the fifth largest investor in programming, with a total of just under $7 billion, while Amazon was in tenth with $4.4 billion.

## Annual programming expenditure – top 10 groups US 2013-2017 ($bn)




Source: IHS Markit from company reports/Channels and Programming Intelligence

## Annual programming expenditure – top 10 groups worldwide 2013-2017 ($bn)




Source: IHS Markit from company reports/Channels and Programming Intelligence

- With worldwide programming expenditure of $12.4 billion, Walt Disney Co was at the top of the list, one of eight US-based groups in the top ten. NBCUniversal with $11.8 billion and Fox with $11.5 billion were next.

- Sky was one of the two non-US groups in the top ten with spending of $6.45 billion. The other was Japan's public broadcaster NHK with $4.8 billion.

# Unparalleled Global Coverage, Combined with In-depth Local Knowledge.

## Key Service Overviews

### Channels & Programming

Providing the complete picture of the global channel and programming content industry.

Providing the complete picture of the global channel and programming content industry with detailed market sizing metrics including revenues for TV channels and online services at worldwide and country levels, segmented by advertising revenues, public funding, carriage fees and direct-to-consumer subscriptions.

### Consumer Platforms & Ecosystems

Global, expert analysis of the consumer strategies of major technology platforms, ecosystems, and operators – and how they reach, monetize, and engage their users.

Strategic focus on the business models and services transforming the digital world, including apps and content, messaging and communications, payments and commerce, digital assistants and AI, investments and M&A.

### Connected Devices & Media Consumption - Premium

Combines key addressable market information with in-depth consumer survey data and analysis to provide unparalleled coverage of connected devices and media consumption.

Connected Devices datasets provide highly accurate, continuously-updated information on the audio-visual connected device landscape, and on the technology ecosystems that content service providers rely on in order to distribute online media. Supported by a global team of analysts, and covering 75 countries, the service allows any firm with a stake in digital-media-and-technology markets to understand how connected devices can be used to drive demand for a vast array of media distribution services.

## Games - Premium

Detailed coverage of the games sector, with access to a continuous flow of research across geographies, topics and platforms.

Coverage includes a tactical by territory view of games content and games hardware opportunities by each and every segment of the market with Industry competitive dynamics including: company and title performance, content pricing, funding and acquisition analysis.

## TV & Online Video - Premium

Key metrics for video distribution across TV and online video platforms for over 100 individual countries

Provides access to constantly updated and detailed company and market level data analysis on the online video and pay and free television industries, this includes detailed coverage of 100+ countries worldwide. Online video data is compiled and presented at company level for advertising and subscription data, and at market level for transactional data.

## Cinema

Helping you see the big picture in the global film and cinema sectors.

Provides the means to track market and technology developments in the global film and theatrical industries by analyzing performance metrics for specific companies and regions. This service provides accurate, continuously updated market data, forecasts based on a thorough knowledge of historic and current statistics, and topical reports that will bring you a deeper perspective on the landscape.

# Global Media & Advertising Research

Broad breath and depth coverage of the markets and strategies of TV Media & Content, Connected Devices, Digital Media, Advertising, Cinema, Games and Video worldwide.

## Do you need to…

- Navigate content distribution strategies?
- Deliver media or advertising to customers?
- Better evolve monetization?
- Take best advantage of new technologies?
- Obtain detailed consumer behavior and consumption analysis?

## Why IHS Markit? We cover…

- Every major studio and content provider, worldwide
- “Bottoms-up" research methodology
- Direct survey of appropriate firms and institutions
- Expertly developed models and forecasts

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**250+**
**analysts worldwide**

**127,000+**
**In 2017, more than 127,000 articles included IHS Markit Technology statistics and analyst commentary.**

Deep market insight

Custom research & consulting

## Research categories & Key topics covered

**TV Media & Content**
- TV & Online Video
- Television media

**Connected Devices**
- Connected devices & addressable consumers
- Direct-to-Consumer

**Digital Media**
- Connected devices and addressable consumers
- Virtual reality & entertainment

**Advertising**
- Mobile & Online Platforms
- Blockchain poised to disrupt ad value chain

**Cinema**
- Content distribution, packaging and production
- 3D Screens and Virtual Reality

**Games**
- Virtual Reality
- Bundles in digital console stores

**Video**
- Regional growth disparities
- Online Video Marketplace

## Solution Intelligence Services

- Advertising
- Broadband Media
- Broadcast & Internet Video Software, Security & Analytics
- Cinema
- Connected Devices & Media Consumption
- Consumer Platforms & Ecosystem
- Games
- Home Entertainment
- Operator Multiplay
- TV Channels & Programming
- TV Media
- TV & Online Video
- TV Sets
- Video Media

**+ Databases, reports, and market trackers**

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Mr. Knapp oversees the global advertising research, consulting and forecasting practice. His key research areas include the future of TV and video, social media platforms, advertising-funded business models, programmatic advertising, AI-driven marketing, and data strategies.

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## About IHS Markit

IHS Markit (Nasdaq: INFO) is a world leader in critical information, analytics and solutions for the major industries and markets that drive economies worldwide. The company delivers next-generation information, analytics and solutions to customers in business, finance and government, improving their operational efficiency and providing deep insights that lead to well-informed, confident decisions. IHS Markit has more than 50,000 key business and government customers, including 85 percent of the Fortune Global 500 and the world's leading financial institutions. Headquartered in London, IHS Markit is committed to sustainable, profitable growth.

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IHS ENERGY

# Why the Oil Sands?

## How a remote, complex resource became a pillar of global supply growth

July 2015

ihs.com

**STRATEGIC REPORT**

Canadian Oil Sands Dialogue | Special Report

**Kevin Birn**
Director, IHS Energy

**Jeff Meyer**
Associate Director, IHS Energy

# Contents

# Why the Oil Sands?

## How a remote, complex resource became a pillar of global supply growth

### Key implications

From 2005 to 2014—despite cost escalation, environmental scrutiny, and delays in new pipeline capacity—production from the Canadian oil sands increased 1.2 million barrels per day (MMb/d), or over 128%, propelling Canada to third place in global oil supply growth. Why has oil sands production growth endured, despite the multiple hurdles?

- **Technological innovation coupled with high global oil prices supported growth in oil sands production over the past decade.** Key enablers were the vastness of the oil sands resource open to private and foreign investment and the stable political and economic climate.

- **Oil sands growth has strengthened energy security by geographically diversifying supply while providing economic benefit to Canada and the United States.** This growth made Canada the United States' largest source of oil imports (exceeding volumes from all of OPEC combined toward end-2014), thereby displacing more distant sources of supply, bolstering continental energy security, and supporting economic growth.

- **Oil sands growth has continued despite challenges that have emerged.** Oil sands have faced escalating cost, concerns over the environmental impact of development (both regional impacts on air, land, and water and global impacts in the form of rising greenhouse gas emissions), and delays in obtaining new pipeline takeaway capacity.

- **Oil sands remain on a growth track—with a further 800,000 barrels per day of new supply projected by 2020—which will maintain Canada's position as the third largest source of global supply growth over this period.** The recent plunge in oil prices is a fresh test for this resource. But globally more than 30 MMb/d in new oil will be needed by 2030 just to offset field declines—to say nothing of meeting rising oil demand. Oil sands potential remains intact, and could figure prominently in this imperative.

—July 2015

 

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# Why the Oil Sands?

## How a remote, complex resource became a pillar of global supply growth

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### About this report

**Purpose.** Since 2009, IHS has made public its research available on issues surrounding the development of the Canadian oil sands. Leveraging prior research efforts, this report summarizes the story behind the rise of oil sands growth over the past decade and a half. This includes an explanation of the key factors that drove investment in oil sands production. This discussion includes both the benefits and the key challenges arising from growth.

**Context.** This report is part of a series of papers from the IHS Canadian Oil Sands Dialogue. The Dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Participants include representatives from governments, regulators, the oil and gas industry, academics, pipeline operators, refiners, and nongovernmental organizations. This report and past Canadian Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Toronto, Ontario, on 24 June 2014, as well as participant feedback on a draft version of the report. IHS has full editorial control over this report and is solely responsible for its content (see the end of the report for a list of participants and the IHS team).

**Structure.** This report has five parts and an appendix:

- How a remote, complex resource became a pillar of global oil supply growth
- Innovation and market forces spurred oil sands development
- The oil sands have provided energy security and economic uplift to North America
- Challenges to oil sands growth have emerged
- The role of oil sands in continuing to meet global oil demand

## How a remote, complex resource became a pillar of global oil supply growth

From 2005 to 2014, production from the Canadian oil sands rose by 1.2 million barrels per day (MMb/d), making Canada (and the oil sands alone) a cornerstone of global supply growth and the third fastest growing national source of supply in the world (see Figure 1).[1] Canada currently produces more oil (conventional, unconventional, and oil sands) than any OPEC country except for Saudi Arabia. Growth has prevailed despite multiple challenges, including escalating capital costs, environmental concerns, and difficulty in securing access to new markets.

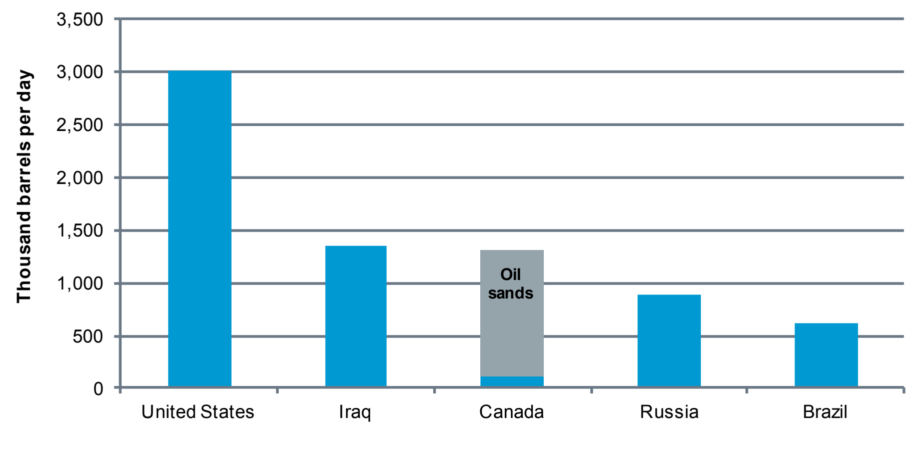
How has oil sands production growth continued, despite multiple challenges? Can output continue to expand—even when confronted with much lower oil prices?

1. Unless otherwise noted, oil sands production denotes synthetic crude oil (SCO) and non-upgraded bitumen.

This report addresses these two questions, first by looking back and then by looking ahead. It examines the factors behind rising production, the energy security and economic benefits associated with oil sands development, and the nature of the challenges the sector faces. The report concludes by exploring the expected role of the oil sands in meeting global oil demand in the years ahead.

Figure 1

**Top five national sources of global supply growth (inclusive of growth and declines), 2005–14**




Notes: Inclusive of supply growth and production declines divided by uncoventional and conventional.
Source: IHS



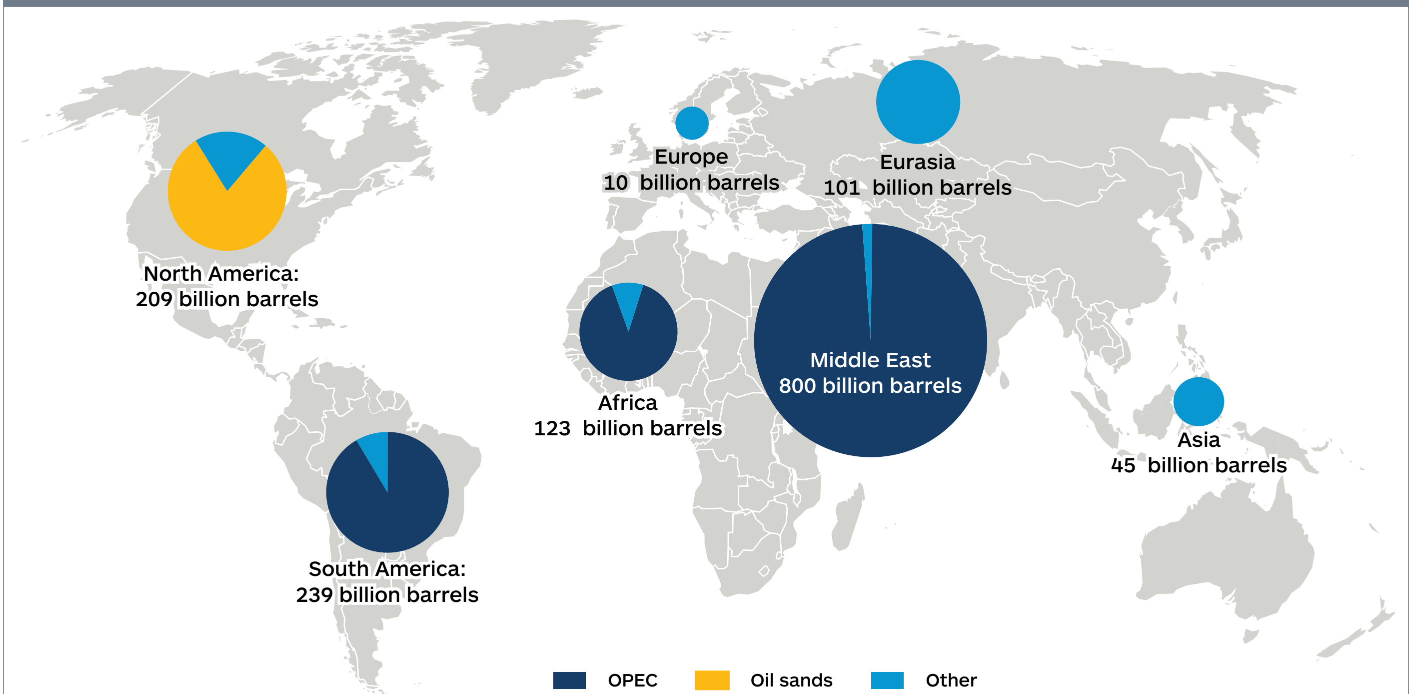
## Innovation and market forces spurred oil sands development

The enormous scale of the oil sands resource has been known for more than a century. With about 167 billion barrels of oil estimated to be economically and technically extractable, the oil sands are the third largest source of proved reserves in the world after Saudi Arabia and Venezuela—and the only reserves of this scale outside of OPEC (see Figure 2).

Development of the oil sands did not occur overnight. It is a story of perseverance, innovation, collaboration between industry and government, a stable investment climate, and North American capital investment dating back more than a century.

Figure 2

**Proven global reserves by major geographic region, Canadian oil sands, and OPEC**




Source: EIA, 2011, 2014

For much of the oil sands' history, crude extraction was constrained by the remote location, harsh climate, and technological challenges. As early as the 1880s, the Geologic Survey of Canada attempted to separate bitumen from the sands, clays, and water that make up the oil sands. In the subsequent decades, engineers and researchers from government, academia, and industry collaborated to devise a commercially viable extraction process. The use of hot water to separate out the bitumen was a focal point of this work.

Progress was slow. It wasn't until 1967 that the first large-scale commercial oil sands mining operation opened near Fort McMurray, Alberta, under the banner of the Great Canadian Oil Sands, a venture of US-based Sun Oil Company. A decade later, in 1978, the Syncrude project, a consortium of private and public interests, brought online the second oil sands mine.[2] In 1984, Imperial Oil opened the first thermal extraction facility near Cold Lake, Alberta. Through a process called cyclic steam stimulation (CSS; also known as "huff-and-puff"), steam is injected at regular intervals into the reservoir to reduce the bitumen's viscosity. Between steam injection intervals, the warmed bitumen is recovered through the same wellbore. However, owing to comparatively low oil prices in the second half of the 1980s and in the 1990s, as well as technological limitations, operators could extract oil only from limited areas—either where oil sands lay close enough to the surface to permit mining or where reservoir properties would support economic extraction by CSS. By 2000, oil sands production topped 600,000 b/d.

## Technological innovation and rising oil prices

It wasn't until the early 2000s that a combination of technological innovation and rising oil prices spurred marked growth in oil sands investment and production.[3] In 2001, the first commercial steam-assisted gravity drainage (SAGD) project came online.[4] The project was the result of a collaboration between industry and government in the previous decade. The advent of horizontal drilling permitted the deployment of SAGD to access thinner reservoirs than could be tapped using CSS. Further refinements in horizontal drilling technology permitted access to shallower deposits over time. Advancements were also made in mining. In the run-up to the 2000s, the introduction of hydrotransport—a process that mixes crushed ore with warm water for transport from the mining operation to the separation facility—made economic the opening of more distant mines without the need for new processing facilities.[5] Advancements in horizontal drilling, SAGD, and hydrotransport transformed the oil sands industry, making it economically feasible to extract bitumen from many more areas.

Advances in oil sands extraction technology coincided with the beginning of a steady rise in oil prices. In the first part of the new century, surging demand from China and other emerging economies took the oil market by surprise, while a series of production disruptions—including in Venezuela, Iraq, Nigeria, and the Gulf of Mexico—reduced supply. These supply and demand forces, and a market psychology that the world was running short of oil, pushed prices higher. The price of West Texas Intermediate (WTI), the US inland benchmark, more than quadrupled between 2002 and the first half of 2008, rising from an average of $26 per barrel (bbl) to $111/bbl. Prices softened during the Great Recession (2008–09) but in time rebounded.

Since 2000, oil sands production has grown by 1.5 MMb/d—more than six times the growth in the prior three decades (see Figure 3).[6]

2. In 1978, members of the Syncrude project were Imperial Oil (31.25%), Cities Services (22%), Gulf Oil (16.75%), the Government of Alberta (10%), the Government of Ontario (5%), and the Government of Canada (15%).

3. Early oil sands in-situ projects also benefited from a change in the fiscal system. In 1996, the Government of Canada extended to in-situ projects an accelerated capital cost allowance (CCA) that had already been in place for a number of years for mining projects. (An accelerated CCA has the effect of deferring taxes.) The accelerated CCA for oil sands projects was phased out in 2014. For more information, see https://www.nrcan.gc.ca/mining-materials/taxation/mining-taxation-regime/8892#lnk6.

4. SAGD utilizes well pairs that travel horizontally through the oil sands deposit, one placed vertically above the other. The top well injects steam, mobilizing the bitumen, which travels with gravity's help down to the lower well for recovery.

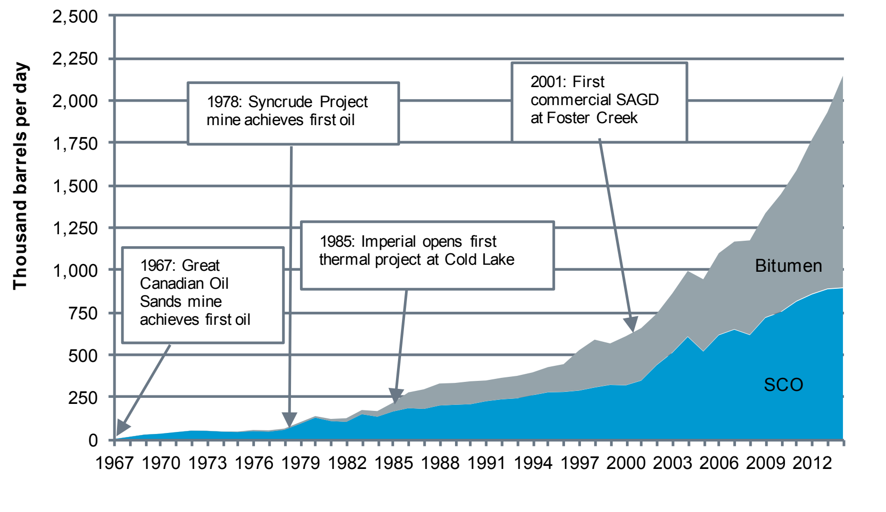
5. Hydrotransport also had the advantage of lowering the temperature (and therefore energy) in the separation process, which improved economics and greenhouse gas (GHG) intensity. Another large mining technology development during this period was a transition from bucket-wheel excavation to more reliable truck-and-shovel operations.

6. Four-fifths of this growth—1.2 MMb/d—occurred over the past decade (2005–14). In 2014, oil sands production reached 2.1 MMb/d—exceeding the total crude production of the sixth largest OPEC member, Nigeria.

## The oil sands: A large resource in a stable jurisdiction next to the world's largest crude oil market

Figure 3

Oil sands production history, 1967–2014




Source: Alberta Energy Regulator, IHS Energy

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The investment capital that enabled the sharp rise in oil sands production over the past decade-and-a-half would not have flowed to the extent that it did were it not for strong fundamentals—a vast resource in a stable jurisdiction, open to private capital, and adjacent to the world's largest economy (the United States). Canada stands out—along with the United States—as one of the most stable investment climates among major oil reserve holders. According to IHS Country Risk, which rates the investment climate of over 200 nations globally, Canada ranks as the 12th most stable nation globally and the second most stable among major reserve holders globally, behind Norway.[7]

Canada's close geographic, political, and economic relationship with the United States further aided development of the oil sands. The United States has been a significant source of investment and technical know-how for oil sands development. IHS estimates that in 2012, over a quarter of oil sands production was backed by US-based companies, and over half of the equity was held by US citizens.[8] Also, as the world's largest oil consumer, the United States has been a consistent source of demand for growing oil production from the oil sands. We discuss the economic and energy security impacts in more detail in the next section.

## The oil sands have provided energy security and economic uplift to North America

Rising oil sands production has yielded energy security and economic benefits for North America, which is a highly integrated energy market. Crude flows mostly south, though some also flows north to meet refinery demand across Canada and the United States.[9]

In a precarious global geopolitical landscape, Canada has stood out as a reliable oil supplier—in terms of both political stability and availability of supply. In recent years a number of major oil exporters in the Middle East, Africa, Eurasia, and Latin America have been beset by political and economic turmoil. Yet North American supply has grown, displacing offshore imports and shoring up North American energy security. The United States and Canada are each other's largest crude oil export market, with Canada by far the largest source of US crude imports, and with the oil sands alone being

7. According to the IHS Country Risk rankings, the most stable large reserve holders (with more than 5 billion barrels in proved reserves), as of the second quarter of 2015, are Norway, Canada, the United States, and the United Arab Emirates. These nations ranked, respectively, 7th, 12th, 15th, and 32nd against all nations included in IHS Country Risk. The rankings are based on six risk criteria: political, economic, legal, tax, operational, and security. For more information, see www.ihs.com/industry/economics-country-risk.html.

8. See the IHS Oil Sands Dialogue Special Report *Oil Sands Economic Benefits: Today and in the future,* February 2014, www.ihs.com/oilsandsdialogue.

9. According to the Energy Information Administration (EIA), Canada is one of the few international outlets for the growing volumes of US light, tight oil. Although the United States restricts the export of most crude, movements to Canada are permitted. US crude oil exports to Canada rose from 67,000 b/d in 2012 to over 400,000 b/d by the end of 2014.

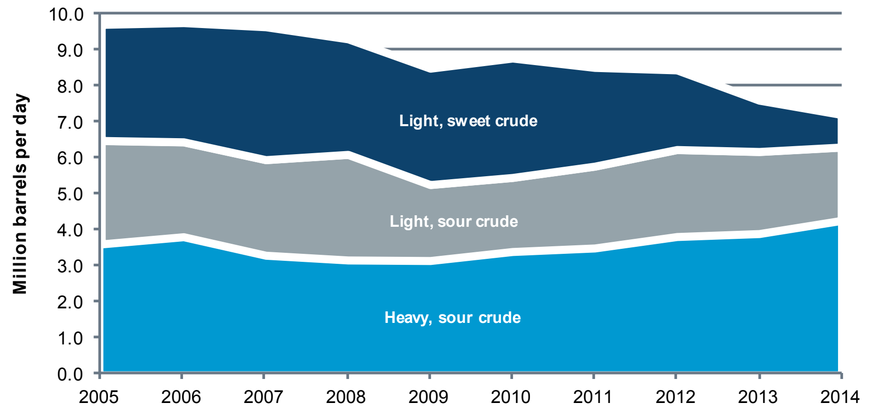
the United States' single largest source. A combination of growing Canadian and US supply led Canada to overtake the cumulative US imports from all of OPEC toward the end of 2014.[10]

The advent and tremendous growth of tight oil (and shale gas) has fundamentally changed the North American energy market, but it has not—and is not expected to—crowd out oil sands supply. As US oil production rose and demand remained relatively steady, net imported oil as a share of total domestic consumption declined from 57% in 2008 to 27% in 2014, according to the EIA. The majority of this decline has been in offshore imports of light crude oil. One implication for the oil sands is that SCO—a light crude that is the product of upgrading bitumen in Alberta—has faced increased competition from US tight oil. Lacking alternative export market opportunities, SCO, which has historically priced at a premium to WTI, has traded below WTI since 2012.[11]

Compared with light oil imports, US imports of heavy oil have remained relatively steady and even increased moderately in 2014 (see Figure 4). This is because the US market—especially the US Gulf Coast (USGC)—has a large inventory of deep conversion refineries built specifically to process heavy crude oil. Since 1992, over $85 billion has been invested in processing heavier grades of crude oil in the USGC region alone ($100 billion if investments in the Midwest are included).[12] These refiners will not wish to idle their heavy capacity and will continue to demand heavy crude oil. Nearly a third of the refinery capacity in the USGC—about 2.7 MMb/d out of 9.2 MMb/d of total capacity—is geared toward running heavy, sour crudes.[13]

Figure 4

**US net crude imports by type, 2005–14**




Notes: IHS defines light, sweet crude oil as having API gravity greater than 28–30° and sulfur content of less than 1%. Light, sour crude oils are defined as those of greater than 28–30° API and sulfur content greater than 1%. Heavy, sour crudes are those below 28–30° API with sulfur content greater than 1%. High total acid number (TAN) crude oils are not shown in this figure.
Source: IHS Energy



With US heavy crude oil import demand largely unscathed by US tight oil, increasing volumes from the Canadian oil sands are expected to come largely from heavy crude oil or from bitumen blends. In contrast, production volumes from some other large sources of US heavy oil imports, including Venezuela and Mexico, have been declining.[14] IHS projects that Canada's oil production will continue to rise through the end of the decade, while the trajectories of output from Venezuela and Mexico are expected to be downward in this period.[15]

In this way, growing oil sands supply and tight oil can be complementary, and oil sands exports to the United States are expected to increase. Both sources represent incremental supply that fits specific refinery demand, displacing more distant alternative sources of supply and contributing to greater North American energy security.

10. According to the EIA, in 2014, US crude imports from Canada averaged 2.9 MMb/d and from OPEC 3.0 MMb/d. From September 2014 to the end of that year, US crude imports from Canada exceeded those from all of OPEC.

11. From 2012 to 2014, the price of SCO averaged more than $1/bbl below WTI, whereas in the prior five years (2007–11), SCO averaged about $3/bbl above WTI.

12. For more information, see the IHS Special Report *US Crude Oil Export Decision: Assessing the impact of the export ban and free trade on the US economy,* 2014, page III-13 (www.ihs.com/crudeoilexport).

13. See the IHS media release *Vast Majority of Crude Oil Transported via Keystone XL Pipeline Would Be Consumed in the United States.*

14. Canada, Venezuela, and Mexico were the three largest suppliers of US imports of heavy crude in 2014. IHS estimates that the United States consumed about 4.5 MMb/d of heavy, sour crudes in 2014, of which about 40% came from Canada.

15. IHS anticipates that it will take some time for the historic reforms opening Mexico's oil sector to foreign investment to bear fruit. Mexico is still in the process of securing foreign capital and technology. Also, large projects of the type that will likely be important for arresting—and reversing—declining output have long lead times.

## Economic benefits from oil sands for North America

In addition to enhancing energy security, rising output from the oil sands has contributed to economic activity in Canada and beyond, most particularly in the United States. For Canada, oil sands development has helped support overall economic output, jobs, and government revenues across the country. Including direct, indirect, and induced effects, IHS has estimated that oil sands development contributed C$91 billion (or about 5% of GDP) to Canada's economy in 2012 and more than 475,000 jobs (roughly 3% of all employment nationally). These included relatively well-paying positions in the engineering, construction, and project management fields.[16]

Because of the length of oil supply chains, the economic benefits of the oil sands extend beyond Canada—and in particular to the United States. The trade linkages between the two countries are large and deep, with flows totaling more than half a trillion dollars each year. IHS has estimated that oil sands investment resulted in imports of C$16 billion in goods and services from outside Canada in 2012.[17] Most of these imports would have come from the United States. According to the Canadian Association of Petroleum Producers, more than 1,900 US companies supplied goods and services to the oil sands industry in Canada.[18] For example, Caterpillar, a global manufacturer of construction equipment headquartered in Illinois, makes large mining trucks that are used in several oil sands mining operations.

For crude oil specifically, with US refiners being the largest recipients of Canadian oil exports and US-headquartered companies and citizens having a large direct stake in development, the United States has also benefited from oil sands development.

# Challenges to oil sands growth have emerged

As production in the oil sands has increased over the past decade, challenges to growth have emerged:

- Escalating costs
- Environmental concerns
- Delays in the timing of incremental pipeline capacity to new markets

In the sections below we discuss each of these challenges and their impact on oil sands development.[19]

## A history of cost escalation

Over the past decade, cost escalation—at times rapid—has eaten into the economics of oil sands projects. Although costs for greenfield in-situ projects before the end of 2014 were arguably within the range of other new sources of supply globally, greenfield mining projects have found themselves among the more expensive in the global oil industry.[20]

In the 2000s, the cost of developing oil sands projects rose significantly as the cumulative pressure from the many projects under construction outstripped the limited local labor pool and the capacity of the regional service sector.

16. See the IHS Oil Sands Dialogue Special Report *Oil Sands Economic Benefits: Today and in the future,* February 2014, www.ihs.com/oilsandsdialogue.

17. Ibid.

18. According to the Canadian Association of Petroleum Producers, US-based suppliers followed closely behind Canadian ones, with 2,370 suppliers from provinces other than Alberta.

19. IHS has written on all of these issues extensively over the past few years. Prior reports can be accessed at www.ihs.com/oilsandsdialogue.

20. IHS estimates that in 2014 the Dated Brent price required for a typical greenfield oil sands project to break even, assuming a 10% return, was about $70/bbl for SAGD and $100/bbl for a new mine. These break-even estimates compare with $22/bbl for Saudi Arabia, $72/bbl for the Gulf of Mexico, $60/bbl for Brazil, and $75/bbl for North American tight oil in 2014. These figures are meant as a representative average, and within a producing area considerable variability can exist. The recent collapse of oil prices is triggering a global "reset" of industry costs in 2015–16. The IHS Upstream Capital Costs Index, a proprietary IHS index that tracks the cost of developing a global portfolio of upstream oil and gas assets, is projected to fall by about 20% from 2014 to 2016. These break-even cost estimates are "full-cycle," i.e., they include the cost of finding and developing new oil production capacity and then producing it, taking into account fiscal terms. Brent crude–based break-even estimates of landlocked crudes like the oil sands are subject to the differential between inland and global crude prices. With regard to upstream costs in the oil sands, similar to other supply sources, it is important to make the distinction between operating (or cash) costs and greenfield capital costs. Oil sands operating costs are much lower than new project capital costs, according to IHS Oil Sands Market Indexes and the IHS Upstream Capital Costs Service.

Upward cost pressure was not unique to the oil sands in this period; indeed, it was a global phenomenon in the upstream industry. Yet cost escalation was particularly acute for some inputs in the oil sands—particularly skilled labor such as electricians and steam engineers—owing to shortages in remote northern Alberta. From 2000 to 2007, the cost of developing an oil sands project increased by an estimated 150%.

Capital cost pressures eased during the Great Recession, but then as oil prices gradually recovered in the wake of the economic downturn, a new wave of capital investment flowed into the oil sands. By early 2012, costs had returned to pre-recession levels. Between 2012 and 2013, with oil prices remaining relatively flat (although at a high level), costs continued to eat into investment returns.

The current lower oil price environment is exerting downward pressure on project costs. Although existing projects are expected to continue to operate, and projects under construction will be completed, a slower pace of construction activity and a delay in unsanctioned projects (those for which significant capital has not been spent) are expected to lower costs. IHS expects new (and delayed) projects to reemerge as global prices slowly recover. Yet, costs for other global sources of supply are also likely to decline as a result of the lower price environment. The ability of the oil sands to continue to compete for capital with projects elsewhere in the world may require a shift in approach by producers to mitigate factors that contributed to periods of sharp cost escalation in prior investment cycles.

## Environmental concerns are both local and global

Over the past decade, the oil sands have been subject to increasing environmental concerns and scrutiny. Concerns have focused on both local and global environmental impacts—with GHG emissions being one of the most contentious issues.[21] This has contributed to new regulations, greater oversight by governments, and lengthier regulatory review of new projects. Overall this has translated into additional costs for the industry as well as uncertainty regarding further regulation. Operators, both individually and in collaboration, have stepped up efforts to accelerate technological solutions to environmental concerns. Yet, differences of opinion—a hallmark of the Canadian oil sands industry—remain over the best approach to future development.

### Local environmental impacts—land, air, water, and waste

At a local level, oil sands development impacts many facets of the environment, including land disturbance and degradation, local air pollution, and waste generation—particularly the fluid waste material from mines, known as "tailings." In the past few years, new regulatory frameworks targeting improved measurement and management of environmental impacts have been introduced, including a shift by regulators to consider the cumulative environmental effects of developments in an area (as opposed to only the impact of the project under consideration) and greater monitoring of regional air and water quality and biodiversity, in part to use as inputs to ensure that industrial development stays within localized and regional limits.[22]

### Global environmental impacts—GHG emissions

At the same time that production growth was kicking into high gear around the mid-2000s, climate change was on the rise as a leading policy issue.[23] With absolute emissions growing with production, oil sands have become a focal point for those advocating a more rapid shift of the world energy mix away from fossil fuels. Campaigns have been mounted to halt future oil sands growth, drawing greater scrutiny by governments (in Canada and elsewhere) and contributing to delays in new pipeline takeaway capacity.

One reason for the focus on oil sands is the relative energy intensity of extraction. On complete life-cycle basis (commonly known as well-to-wheels), 20–30% of emissions occur in production, with the majority (70–80%) of emissions occurring at combustion. On a complete life-cycle basis (well-to-wheels), oil sands are above the US average, emitting

21. For an in-depth discussion of environmental impacts of oil sands development, see the IHS Oil Sands Dialogue Special Report *Critical Questions for the Canadian Oil Sands,* 2012, www.ihs.com/oilsandsdialogue.

22. The Lower Athabasca Regional Plan and Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring are examples of such regulatory frameworks. See https://landuse.alberta.ca/REGIONALPLANS/LOWERATHABASCAREGION/Pages/default.aspx and http://jointoilsandsmonitoring.ca.

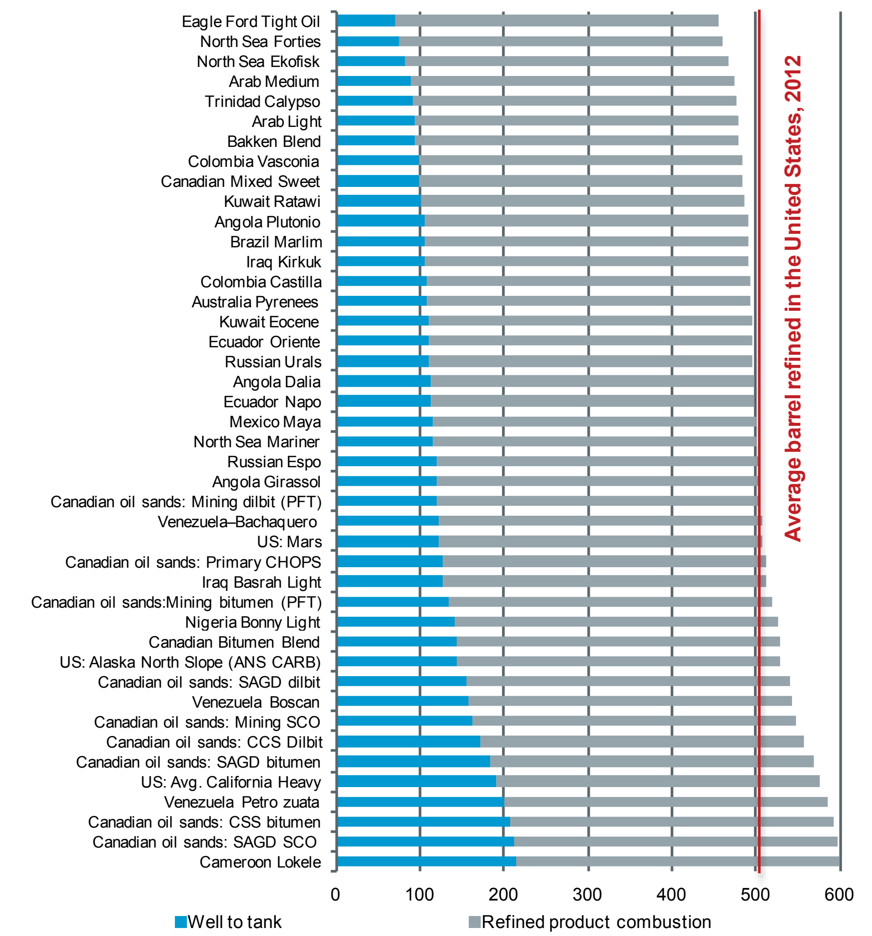
23. See Daniel Yergin, *The Quest: Energy, Security, and the Remaking of the Modern World,* Penguin Books, New York, 2012, Chapter 25.

1–19% more GHG per barrel of crude oil refined in the United States in 2012, with some of the most recent projects trending closer to the US average.[24] Yet, the oil sands are not unique in this regard. There are other crude oils—including those from Venezuela, California, and Alaska—that have a GHG intensity within a similar range to oil sands (see Figure 5). A 2014 IHS study found that 45% of all crude oil consumed in the United States in 2012 fell within the intensity range of oil sands crudes, with roughly two-thirds of this volume coming from other sources (non–oil sands crudes).

Figure 5

**Wells-to-wheels GHG emissions for oil sands and other crudes (wide boundary)**




Source: IHS Energy, IHS Oil Sands Dialogue Special Report "Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil," www.ihs.com/oilsandsdialogue.

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The other reason for the focus on oil sands is their emissions growth. Globally oil sands emissions account for about 0.14% of emissions, yet domestically emissions are more material, having increased from 3% of Canada's emissions in 2000 to 9% in 2013 (the last year for which data are available).[25] With production growth expected to continue, emissions growth presents a challenge for the industry, which faces the prospect of additional regulatory measures from both federal and provincial governments.

- **Provincial regulation.** In 2007, Alberta was among the first jurisdictions in North America to regulate GHG emissions for large industrial facilities. These regulations included oil sands production facilities. Since mid-2007, large industrial emitters in Alberta have been required to make a 12% reduction in their GHG intensity (i.e., GHG emissions per unit of output) below a business-as-usual case. Compliance can be met through a combination of intensity improvements, offset purchases, or levy payments of C$15 per metric ton of GHG emitted. Revenues collected from the Alberta levy, fund the development of green technologies. Alberta's policy is set to nearly double within the next two years. In 2017, existing facility will face a 20% intensity target and a $30 per metric ton carbon price. At $30 per metric ton per $CO_2e$, the price paid per ton above the emissions intensity cap will be the same as the price in the Canadian province of British Columbia, which is currently the highest carbon price in North

24. The US average is defined as the weighted average intensity of the entire US crude slate or crude oil consumed in the US in 2012—from light to heavy oil. For a comparison of GHG intensities consumed in the United States, see the IHS Oil Sands Dialogue Special Report *Comparing GHG Intensity of the Oil Sands and the Average US Crude Oil*, June 2014, www.ihs.com/oilsandsdialogue.

25. Estimate of the global share of emissions is based on oil sands' share of Canadian emissions on a carbon dioxide equivalent ($CO_2e$) basis in 2012 and global emissions on a carbon dioxide basis in 2012, excluding land use. Source: Environment Canada (2015), National Inventory Report 1990–2013, 17 April 2015, http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/8812.php, accessed 28 June 2015; World Resource Institute, CAIT 2.0 Database, http://cait2.wri.org, accessed 27 June 2015.

America. Additional climate policy measures, including the potential for an entirely new approach to GHG emissions reduction are expected to be announced by the Government of Alberta in the fall of 2015.[26]

- **Federal regulation.** The Government of Canada has committed to introducing its own regulations for the oil and gas sector, which includes the oil sands. Following a sector-by-sector approach, the government has introduced regulations for the coal-fired power generation sector, with the oil and gas sector expected to follow. Regulations have been expected for a number of years but were most recently delayed owing to concern about introducing an additional financial burden for Canadian producers in the lower price environment of 2015 that may not be borne by competitive sources of supply elsewhere in the world.[27]

Technological innovation holds the potential to improve environmental performance and lower cost. Many improvements have been driven by economic incentives in the interest of greater efficiency. This is the case with the introduction of solvents in place of steam for in-situ extraction and with the aforementioned introduction of hydrotransport. The use of solvents can lower natural gas consumption and thus emissions intensity while also improving project economics.[28] Further innovation is expected to lead to additional improvements; but given the scale of oil sands development, a broad deployment of shared knowledge across operations is essential to delivering material results.

To this end, oil sands producers established the Canada's Oil Sands Innovation Alliance (COSIA) in 2012.[29] In an industry where proprietary technology is seen as critical to success, COSIA is an unconventional collaboration. A major objective of COSIA is to speed up innovation and implement new technologies across the industry to maximize their effectiveness. As of early 2015 the consortium consisted of 13 member companies that collectively accounted for about 90% of oil sands production. The consortium focuses on four areas: tailings management and reduction, water use and improved recycling, reduction of land use, and lowering the GHG intensity of production.

Because technological breakthroughs take multiple years (or decades) to achieve, it is too early to assess COSIA's record. However, the consortium's members account for most of the oil sands production, which suggests a wide acknowledgment of the issues and challenges and creates a broad platform for dissemination and implementation of technologies once they are developed.

## Delay in accessing new markets by pipeline

Since early in the decade, prolific growth in oil sands and tight oil production has overwhelmed existing North American pipeline infrastructure. A number of new pipeline projects on both sides of the border have been proposed to ease the bottlenecks. But environmental opposition to oil sands development has contributed to delays for several projects.

Insufficient market access has manifested as price discounts for oil sands crude—and thus forgone revenue for producers, shareholders, and governments. These discounts have at times been wide and protracted. For example, between 2011 and 2014, the average price difference between Western Canada Select, a heavy crude oil (as priced in western Canada), and Mexico's Maya, another heavy crude oil (as priced on the USGC), was $22. For a total of 10 months during this four-year

26. Alberta's Specified Gas Emitters Regulation (SGER) requires large emitters, defined as facilities emitting more than 100,000 metric tons per year, to reduce their emissions intensity below a baseline. For new facilities, the baseline is based on the average intensity of the first three years of operations; for older facilities (those that predate the start of the regulation), it is based on the average intensity from 2003 to 2005. Newer facilities are required to meet a 2% intensity improvement per year up to the 12% target. On 25 June 2015, the Alberta Government announced changes to strengthen the SGER. In the updated SGER policy, the intensity target will increase from 12% currently to 15% in 2016 and 20% in 2017. Alberta's carbon levy (price) will also rise, from the current value of $15 per metric ton to $20 in 2016 and $30 in 2017. The Government of Alberta also announced the formation of a review panel that will develop options to be used to inform new GHG reduction policy in Alberta. The panel is expected to report its finding in autumn 2015, and an announcement on future Alberta GHG reduction policy is expected from the Government of Alberta in advance of the COP21 Climate Conference in Paris in December 2015. For more information, see: http://aep.alberta.ca/focus/alberta-and-climate-change/default.aspx/, accessed on 28 June 2015.

27. *The Globe and Mail*, "Resources Minister Rickford steps up attack on carbon tax proposals," 3 April 2015, www.theglobeandmail.com/news/alberta/resources-minister-rickford-steps-up-attack-on-carbon-tax-proposals/article23794576/, accessed 13 May 2015.

28. Solvents also substitute for water, which reduces the consumption of both water and natural gas in converting the water into steam.

29. For more information on COSIA, see www.cosia.ca.

period, the differential averaged more than $30. This compares with the differential's five-year monthly average of less than $10 from 2006 to 2010.[30]

With new pipelines still on the drawing board, oil sands producers have increasingly turned to railroads to get their crude to market. Crude-by-rail first rose from tight oil growth in North Dakota to over 700,000 b/d in 2014 (and to over 1 MMb/d across the United States), according to the EIA. Movement of oil sands crude by rail has risen much more slowly, from negligible levels in 2010 to nearly 190,000 b/d toward the end of 2014.[31] Over the past year or so, the rise of crude-by-rail in North America has eased transportation bottlenecks and helped to prevent a recurrence of the deep price discounts of the previous few years. Although crude-by-rail provides flexibility to ship crude to many different destinations, as well as the ability to reach refineries that are not linked to a pipeline network, moving crude by pipeline is generally less expensive and more predictable. Thus pipelines remain the generally preferred option for producers and refiners alike.[32]

Keystone XL is the most prominent proposed pipeline originating in the oil sands to encounter regulatory delays. The pipeline, designed to run from Alberta to the USGC, has become a symbol for those opposed to continued reliance on fossil fuel consumption. Previous IHS research has concluded that construction and operation of the Keystone XL pipeline would not have a material impact on GHG emissions since, with or without oil sands supply, complex refineries on the USGC will continue to demand heavy crudes, which have a similar GHG emissions intensity to oil sands crudes.[33] However, the pipeline has been awaiting a cross-border permit from the US State Department since 2008.[34]

Controversy over proposed pipelines from western Canada is not limited to those that cross international borders. Projects such as the Line 9 reversal, Energy East, the TransMountain Expansion Project (TMEP), and Northern Gateway have all been subject to a high degree of public attention, opposition, and ultimately delay. All four pipelines traverse routes entirely within Canada—the first two eastward and the latter two westward (see Figure 6). The Line 9 reversal has received final government approval in 2014, but additional conditions have contributed to delay the online date.[35] Energy East and TMEP have been advancing through the Canadian regulatory process, but both have faced additional scrutiny from provincial and municipal governments in response to concerns about local and global (i.e., GHG) environmental impacts. Northern Gateway received regulatory approval in 2014, but the project's proponent has yet to announce when it will proceed. In particular, the Energy East, TMEP, and Northern Gateway pipelines would enable oil sands to reach tidewater and gain access to offshore markets.

## The role of oil sands in continuing to meet global oil demand

Global oil demand growth has slowed in the past few years, and the world is currently oversupplied owing largely to prodigious growth in US tight oil production. Reflecting this imbalance, oil prices have fallen to levels last seen during the Great Recession. Nonetheless, IHS, as well as organizations including the International Energy Agency, anticipate that new supplies from a variety of sources will be required in the coming decades to meet rising global oil demand—especially in emerging markets—and to offset maturing oil fields. Just to achieve the latter will require producers to find, develop, and bring online some 30 MMb/d of crude oil production by 2030. This is no small amount of oil—it is equivalent to over one-third of the total global crude demand in 2014.[36] A recent trend of fewer large discoveries of conventional oil, along with little sign that geopolitical turmoil will soon abate, only adds to this imperative. For supply and demand to balance over the longer term, prices will likely need to rise from current levels to support development of a variety of sources—

30. To be sure, the absolute prices of both crudes were lower on an annual average basis in 2006–10 than in 2012–14, which would result in a narrow differential in general. Yet the extent of the differentials in 2012–14 cannot be fully accounted for by higher absolute prices or differences in refining economics or pipeline tolls.

31. These volumes include movements of both oil sands and non–oil sands Canadian production that are both exported and transported entirely within Canada. Diluent that is imported into the oil sands region is not included in these volumes. Source: IHS Energy.

32. For analysis of crude-by-rail market dynamics, see the IHS Oil Sands Dialogue Special Report *Crude by Rail: The New Logistics of Tight Oil and Oil Sands Growth,* December 2014, www.ihs.com/oilsandsdialogue.

33. See the IHS Energy Insight *Keystone XL Pipeline: No Material Impact on US GHG Emissions,* August 2013, www.ihs.com/oilsandsdialogue.

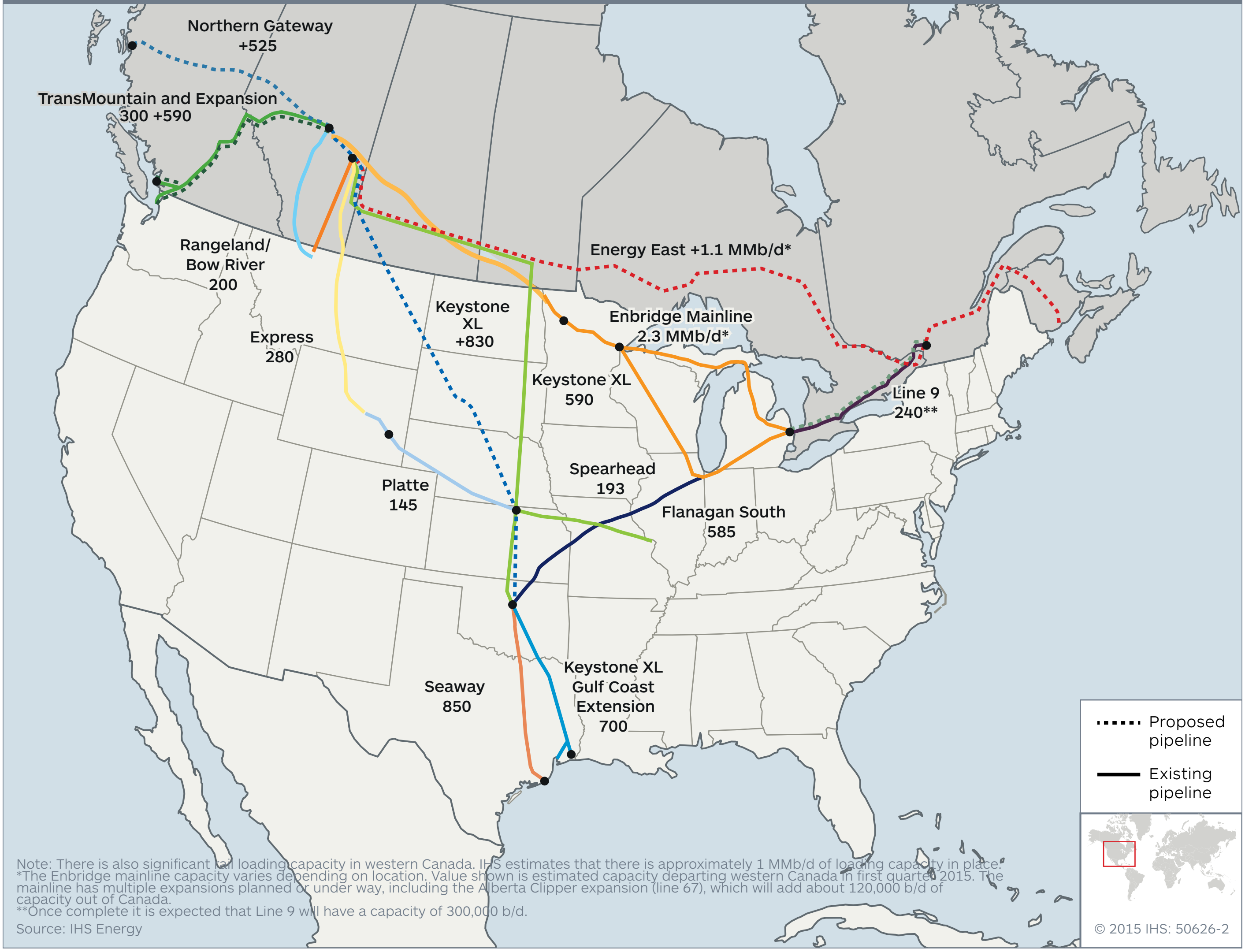
34. The southern leg of the pipeline, running from Oklahoma to the USGC, has already been built. This section did not require State Department approval because it did not cross an international border.

35. *The Globe & Mail,* "NEB imposes new conditions on Enbride's Line 9," 18 June 2015, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/neb-imposes-new-conditions-on-enbridges-line-9/article25014287/, accessed 6 July 2015.

36. Value includes only crude oil, not condensate and other liquids.

Figure 6

**Existing and proposed pipelines departing western Canada (thousand barrels per day)**




Note: There is also significant rail loading capacity in western Canada. IHS estimates that there is approximately 1 MMb/d of loading capacity in place.
*The Enbridge mainline capacity varies depending on location. Value shown is estimated capacity departing western Canada in first quarter 2015. The mainline has multiple expansions planned or under way, including the Alberta Clipper expansion (line 67), which will add about 120,000 b/d of capacity out of Canada.
**Once complete it is expected that Line 9 will have a capacity of 300,000 b/d.
Source: IHS Energy

such as oil sands, deepwater and ultradeepwater, and tight oil outside North America.[37] The "supply challenge"—apparent before the tight oil surge and rarely mentioned today—remains a longer-term issue.

What does this mean for the future of the oil sands? IHS expects output from the oil sands to continue to rise to the end of the decade. To be certain, the oil sands are not immune to the lower prices, and growth will be lower than would have been the case in a higher price environment. Unsanctioned projects will be delayed, and projects under construction will slow—but existing projects and those under construction will continue to operate and come online, respectively. With over 1 MMb/d of capacity currently at various stages of construction in the oil sands, growth will continue. IHS expects an additional 800,000 b/d of production online by 2020, which will maintain Canada's position as the third largest source of supply growth in the world over this period.

In the longer term, the trajectory of oil sands growth is linked to the pace and scale of the global price recovery as well as the ability of industry and governments to manage the challenges it faced even before the price downturn (such as cost escalation, hurdles to accessing new markets, and environmental concerns). Nonetheless, a mix of positive attributes—

37. Ultradeepwater is defined as greater than 5,000 feet of water depth.

including a massive resource base, stable political climate, and openness to private capital—underpins the longer term investment potential in the Canadian oil sands.

## Report participants and reviewers

IHS hosted a focus group meeting in Toronto, Ontario, on 24 June 2014 to provide a forum for oil sands stakeholders to come together and discuss perspectives on the key factors that contributed to oil sands growth. Additionally, a number of participants also reviewed a draft version of this report. Participation in the focus group or in the review of the draft report does not reflect endorsement of the content of this report. IHS is exclusively responsible for the content of this report.

Alberta Department of Energy

Alberta Innovates—Energy and Environment Solutions

American Petroleum Institute

BP Canada

Canadian Association of Petroleum Producers

Canadian Natural Resources Limited

Canadian Oil Sands Limited

Cenovus Energy Inc.

ConocoPhilips Company

Imperial Oil Ltd.

In Situ Oil Sands Alliance (IOSA)

MacDonald Laurier Institute

Natural Resources Canada

Shell Canada

Suncor Energy Inc.

The Mowat Centre

Total E&P Canada Ltd.

TransCanada Corporation

## IHS team

**Kevin Birn,** Director, IHS Energy, leads the IHS Canadian Oil Sands Dialogue. His expertise includes energy and climate policy, project economics, transportation logistics, and market fundamentals. Recent research efforts include analysis of the GHG intensity of oil sands, the economic benefits of oil sands development, upgrading economics, oil sands project economics, and the future markets for oil sands. Prior to joining IHS, Mr. Birn worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada, helping to inform early Canadian oil sands policy. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US Secretary of Energy. Mr. Birn holds undergraduate and graduate degrees in business and economics from the University of Alberta.

**Jeff Meyer,** Associate Director, IHS Energy, focuses on global oil market and industry trends. Prior to joining IHS, 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.

IHS CERA

Special Report

# Oil Sands Economic Benefits

## Today and in the future

January 2014

ihs.com

# Contents

## About this report

- **Purpose.** There is a debate in Canada about the level of benefits of oil sands development. Where does money generated from the oil sands flow go, what are the economic benefits today, and what could they be in the future? This report aims to provide facts and data about the scale of the benefits today and the future potential, including issues related to estimating economic benefits to help inform this discussion.

- **Context.** This report is part of a series from the IHS CERA Canadian Oil Sands 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. Participants include representatives from governments, regulators, the oil and gas industry, academics, pipeline operators, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

- **Methodology.** IHS CERA and IHS Global Insight conducted our own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Calgary, Alberta, on 6 June 2013 and participant feedback on a draft version of the report. IHS 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 team).

- **Structure.** This report has an introduction, three sections, and a conclusion.

  - Introduction: Economic benefits are already here
  - Part 1: Where does money generated from the oil sands flow?
  - Part 2: Challenges in measuring oil sands economic benefits
  - Part 3: Economic benefits today and in the future
  - Conclusion: Greater economic benefits possible in the future

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For clients with access to the IHS CERA website, the following features related to this report may be available online: downloadable data (Excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

# Oil Sands Economic Benefits

**Today and in the future**

## Summary of key insights

- **Canada's oil sands generate economic benefits on a scale greater than Canada's fifth largest economy, the Province of Saskatchewan.** It is estimated that in 2012, oil sands contributed C$91 billion to the Canadian economy, or 5% of GDP, and to 478,000 jobs, or 3% of all jobs in Canada—more than 5 out of 10 provinces.

- **Most of the gross revenue generated by oil sands stays in the oil sands, reinvested in operations.** In 2012, four-fifths of every dollar made by oil sands operations was reinvested into maintaining and moving oil sands production to market. One-tenth of revenues went to government coffers.

- **Oil sands development contributed $28 billion to governments in Canada in 2012; more than half went to the federal government.** In 2012, oil sands investment generated C$15 billion in federal tax revenues, C$12 billion to Alberta, and over C$1 billion to other provinces. The federal share represented 6% of government revenues and was equivalent to half of federal spending on health care transfers in 2012.

- **In a future where oil sands production reaches 3.8 million barrels per day in 2025, oil sands' contribution to Canadian GDP could nearly double, and a third more jobs could be expected.** Between 2012 and 2025, oil sands' contribution to Canadian GDP could grow from C$91 billion to C$171 billion. This would be like adding an economy the size of Saskatchewan today to Canada by 2025. Oil sands could also add over one-quarter of a million more jobs, contributing to 753,000 jobs in Canada in 2025.

- **The above numbers may well understate the economic impact to regions beyond Alberta: to other Canadian regions and the United States.** Comprehensive data on the geographic distribution of direct oil sands investment do not exist. As a result, a greater share of benefits is attributed to Alberta and too few to other regions. Current models are also not ideal for measuring the net effect of a large investment like the oil sands. Given the discussion over oil sands benefits to other regions, the development of more comprehensive tools and data is warranted.

—January 2014

## Introduction: Economic benefits are already here

Oil sands production has more than doubled in the past 10 years, reaching 1.9 million barrels per day (mbd) in 2013.[1] Alongside production growth, oil sands' contribution to the Canadian economy has also expanded. Economic benefits from oil sands development can be measured by the jobs it creates, the goods and services it purchases from other businesses, and the royalties and taxes paid to governments.

In the dialogue surrounding oil sands development, the economic benefits are often depicted as yet to come; however, with annual expenditures already greater than the GDP of 5 out of 10 of the Canadian provinces, the benefits are here.[2] We estimate that in 2012, oil sands contributed to 478,000 jobs in Canada and C$$91 billion in Canadian GDP, or about 3% of total Canadian employment and 5% of GDP.[3] This was on a scale greater than Canada's fifth largest provincial economy—the Province of Saskatchewan. Royalties and taxes collected from oil sands and spin-off activities exceeded C$28 billion, or about C$812 per Canadian in 2012.[4] Oil sands' contribution to Canada could be even greater, with production predicted to more than double to 3.8 mbd by 2025.

The objective of this report is to establish a common understanding of the benefits derived from oil sands spending today and in the future. Some economists contend that the potential costs from oil sands development (such as crowding out of other investments through inflation, impacts of a stronger Canadian dollar, or unaccounted for environmental costs) could offset part of the benefits. Tackling these questions is not within the scope of this report. Each of these questions is complex, difficult to quantify as well as qualify, and potentially thesis worthy.

In addition to this introduction, the report includes three parts and a conclusion:

- Part 1 studies how oil sands operations generate revenue today and where it goes.
- Part 2 investigates some limitations of commonly used data sources and models in measuring economic benefits.
- Part 3 compares the economic benefits of oil sands today to what they could be in 2025.

Some economic terms are used throughout this report to describe how oil sands development generates economic benefits. These are discussed in the box "Common economic concepts in this report."

1. In 2002 oil sands production of synthetic crude oil (SCO) and nonupgraded bitumen was 707,000 barrels per day (bd). Source: IHS CERA.

2. GDP is a common measure of economic activity or standard of living.

3. Unless stated otherwise, all values are in constant Canadian dollars. Source: IHS CERA. Statistics Canada, Gross domestic product, expenditure-based, provincial and territorial, current market prices, Table 384-0038, www5.statcan.gc.ca/cansim/pick-choisir?lang=eng&p2=33&id=3840038, accessed 19 November 2013. Statistics Canada, Survey of Employment, Payrolls and Hours, Table 281-0024, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2810024, accessed 19 November 2013.

4. Source: Statistics Canada, Estimates of population, Canada, provinces and territories, Annual 2012 Estimate, Table 051-0005, www5.statcan.gc.ca/cansim/a05?lang=eng&id=0510005, accessed 29 August 2013.

## Common economic concepts in this report

The total economic benefit from an investment in an economy exceeds the initial spend, since the original investment results in additional spending cycles. This is called the multiplier effect. Like a rock dropped in a pond, an investment in the oil sands creates waves that travel out from the initial investment, interacting and reverberating off other industries and regions throughout the economy. As a consequence, the total effect of an investment is not limited to the size or shape of that initial "rock," but also the interaction with the broader economy. In this regard, economists often refer to three types of economic impacts: direct (the initial investment or rock), indirect (the interactions along the supply chain among industries), and induced (workers who receive income, either from the indirect or direct effect, who in turn spend their earnings). Because of these three effects—direct, indirect, and induced—the total benefit to the economy surpasses the initial investment. Throughout this report we will refer to the sum of these three effects as the "total effect."

- **Direct effect.** This is the direct impact of each new dollar spent in the economy. In the case of oil sands this includes people and companies hired directly by oil sands producers to build, maintain, market, and manage production. It includes employees, specialized labor (welders, pipefitters, engineers, geologists, ecologists, hydrologists, etc.), technical studies and services, as well as other inputs to production (capital expenditure) such as trucks, heavy equipment, drilling rigs, natural gas, and diluents.

- **Indirect effect.** This is the indirect or secondary impact caused by the initial operational and capital investment. It captures the interactions that occur between companies to meet the demands created by the direct effect. For example, companies hired by oil sands firms buy additional goods and services to support their oil sands contracts. One example is an oil sands operator's purchase of new heavy equipment. To meet the demand, heavy equipment manufacturers have to hire more workers; purchase more steel; and acquire additional parts from their suppliers (other companies) such as tires, bearings, pistons, air filters, lubricants, hydraulic systems, and technology. In turn the companies supplying these parts generate demand for their own inputs to production, and so on. All of this spending is considered the indirect effect.

- **Induced effect.** The induced effect is also called the "income effect." When an investment is made in an economy, employment results from both the direct and indirect effect. In exchange for their labor, workers are paid an income. When the workers' wages are spent back into the economy on goods such as food, vehicles, houses, utilities, and financial services, these expenditures generate additional economic activity. Businesses respond to increased consumer spending by hiring new workers or purchasing additional inputs required to ramp up their capacity. All of this spending is considered the induced effect. Although it is perfectly sound that direct and indirect effects drive labor income, which induces activity in an economy, inclusion of induced effects for large, persistent investments such as the oil sands can be a source of criticism, since in the absence of the sustained oil sands investment, some part of the employment would still exist.

## Commonly used indicators for measuring economic benefits

In this report we used four indicators of economic benefit. These are defined here:

- **Gross domestic product (GDP).** GDP is a common indicator of economic performance or standard of living. It is estimated from the total value of goods and services purchased or the total income earned in an economy. GDP is often criticized as an incomplete measure of an economy, as it does not account for income equality, value of a nation's assets, quality of life, or environmental externalities.

- **Employment.** This measures the number of people or positions financially supported by an economic activity or investment.

- **Government revenue.** This quantifies the money received by governments from user fees, taxes, or royalties as a result of economic activity. In our analysis, we considered taxes from both provincial and federal government, including corporate taxes, consumptions-based taxes, and personal income taxes. Royalties were also included.

# Part 1: Where does money generated from the oil sands flow?

This part of the report explores how money is generated from oil sands and where it goes. It is subdivided into two parts. The first half takes a detailed looked at oil sands investment in 2012: where and how the money flows into, through, and from operations. The second half examines the ownership structure of oil sands operations.

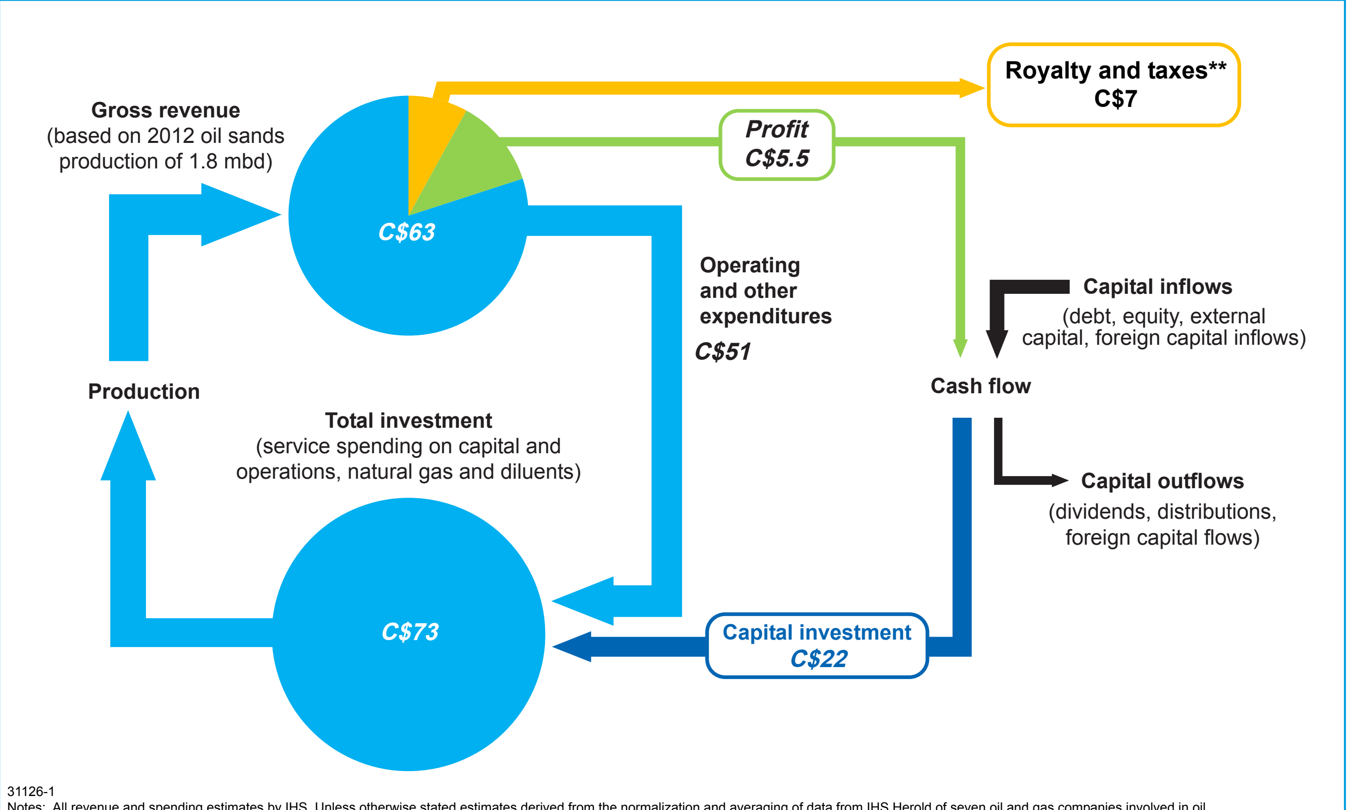
## Where does money generated from and invested in the oil sands go?

To answer the question of how the oil sands generate wealth, we drew upon a method first devised by ARC Financial Corp. dubbed "the oil sands investment cycle."[5] Figure 1 applies revenue and spending estimates derived solely by IHS to the ARC Financial Corp. method. A detailed description of each aspect of the oil sands investment cycle is explained in the paragraphs that follow.

As shown in Figure 1, in 2012 the industry spent about C$73 billion, which was used to sustain production from existing oil sands operations and to fund new capital projects. Although the focus is typically on new capital investment, the majority of capital spending in 2012—about 70%—went to sustain production from

FIGURE 1

**Oil sands investment cycle** (billions of Canadian dollars)*

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Notes: All revenue and spending estimates by IHS. Unless otherwise stated estimates derived from the normalization and averaging of data from IHS Herold of seven oil and gas companies involved in oil sands production. Collectively these companies account for 67% of production in 2012. Companies included: Canadian Natural Resources Ltd., Canadian Oil Sands Limited, Husky Energy Inc., Suncor Energy, Inc., Imperial Oil Ltd., Cenovus Energy Inc., and MEG Energy Corp. Joint venture and partnership interests were adjusted when accounting for shares of production.

*Detailed description of each category in investment cycle provided in the following pages.

**Estimate of government revenues includes provincial and federal corporate taxes and royalties.

Source: All numbers (revenue and spending estimates) by IHS CERA and IHS Herold. Investment cycle concept from ARC Financial Corp,(2011), "Turmoil and Renewal: The fiscal pulse of the Canadian upstream oil and gas industry," http://arcfinancial.com/research/pub/.



5. ARC Financial Corp (2011), "Turmoil and Renewal: The fiscal pulse of the Canadian upstream oil and gas industry," http://arcfinancial.com/research/pub/.

existing operations.[6] Governments in Canada (provincial and federal) are also large beneficiaries, collecting about C$7 billion in royalties and taxes directly from oil sands operators in 2012.[7]

Unlike oil sands production, which to date has been geographically restricted to the Province of Alberta, the spending depicted in Figure 1 is not.[8] For instance, engineering and administration services, equipment, and chemical manufacturing associated with oil sands development occur beyond Alberta in other Canadian regions, the United States, and elsewhere.

What follows is a detailed breakdown and description of the oil sands investment cycle depicted in Figure 1.

- **Gross revenues from production, C$63 billion (2012)**. Money is generated from oil sands development from the extraction and subsequent sale of crude oil. With growing production, industry revenues have more than doubled in the past five years. Gross revenues in 2012 were C$28 billion more than in 2007.[9] Although revenues were substantial, the potential was greater. Had western Canadian crude oils not been subject to price discounts owing to export bottlenecks, oil sands revenues could have been C$11 billion higher in 2012.[10] With expenses being covered, higher revenues would have contributed to greater profit and government royalties and taxes, as discussed below.

- **Royalties and taxes paid by oil sands producers, C$7 billion (2012).** In 2012, Alberta received C$4 billion in royalties from oil sands operations, and we estimate that oil sands operators paid about C$3 billion in taxes to the Alberta and federal governments.[11] Similar to gross revenues, had oil sands crudes not been subject to a price discount in 2012, royalties and taxes would have been greater. In fact, price discounts contributed to a Government of Alberta deficit in fiscal year 2012/13.[12]

- **Profit from oil sands operations, C$5.5 billion (2012).** We estimate that only one-tenth of oil sands revenues, or C$5.5 billion in 2012, was profit. The rest of oil sands revenues went toward sustaining production or were paid to government for royalties and taxes. Profit and taxes are the only part of revenues that could move beyond oil sands operations. However, not all profit will necessarily leave oil sands development. Some may be reinvested into new capital projects to expand production. Profits that do exit from oil sands development can be used to pay down debt, be invested into capital projects beyond the oil sands (i.e., other oil production opportunities), or paid out as a dividend to shareholders as a return on investment. Where profit ends up, domestically or internationally, depends on where the capital is reinvested or where the debtor and shareholders originate. Details on oil sands ownership are presented later in this section.

- **Operating and other expenses (including employee wages), C$51 billion (2012).** Four-fifths of every dollar generated by the oil sands went into maintaining production in 2012. This includes the cost

6. Referring to Figure 1, we estimated that oil sands operating and other expenditures were C$51 billion of the total investment of C$73 billion in 2012.

7. Royalties were C$4 billion. Source: Government of Alberta, http://www.energy.alberta.ca/about_us/1702.asp,accessed 7 November 2013. Source of tax estimate from IHS CERA and IHS Herold. For more information on IHS tax estimate, see Figure 1 footnotes.

8. Oil sands deposits are found principally in Alberta, with some overlap into the adjacent Province of Saskatchewan.

9. Based on crude oil supply and the annual average crude oil prices expressed in constant 2012 Canadian dollars for 2012 and 2007. In 2012: 1,291,000 bd of bitumen blend at an average Western Canadian Select (WCS) price of C$72 per barrel and 862,000 bd of SCO at an average Syncrude Sweet Blend (SSB) price of C$91 per barrel. In 2007: 714,000 bd of bitumen blend at an average WCS price of C$49 and 652,000 bd of SCO at an SSB price of C$75 per barrel. WCS is a western Canadian heavy crude benchmark price, and SSB is a benchmark price for SCO. Source: IHS CERA.

10. Estimate based on 2.1 mbd of oil sands supply consisting of 34% light SCO and 66% heavy bitumen blends, subject to reduced prices in 2012. Some SCO is present in bitumen blends as a blending agent. Adjusting for quality and transportation costs, light oil sands crudes were valued $11 per barrel lower than on the US Gulf Coast (USGC), and heavy crudes were valued $17 per barrel lower than the USGC.

11. Source: IHS Herold and IHS CERA. For more information see Figure 1 footnote. Source of royalty payments from the Government of Alberta. http://www.energy.alberta.ca/about_us/1702.asp,accessed 7 November 2013.

12. Source: Government of Alberta, Alberta's Fiscal Challenge, http://alberta.ca/fiscal-challenge.cfm,accessed 2 October 2013.

of oil sands workers (direct oil sands employees and those employed by contractors, suppliers, and other service companies), maintenance and repair work, administration, cost for energy such as natural gas and power, and other expenses such as the purchase of diluent for pipelining bitumen. Without this reinvestment, production levels would not be sustained.

- **New capital investment, C$22 billion (2012).** New capital investment in the oil sands funds future production growth. Figure 1 depicts the importance of access to capital for oil sands growth, since the current level of required investment greatly surpasses what is available from profits. IHS estimates that in 2012, new capital investment was four times higher than profit, topping C$22 billion. Investments made in the past few years (or longer) contributed to supply growth of 245,000 bd in 2012.[13] Funds for new capital investment can come from the sale of new corporate debt and equity or from new business entrants (through acquisition, new partnerships, and/or joint ventures [JVs]).

- **Total investment (service spending), C$73 billion (2012).** Total capital investment is the sum of new capital investment and operating and other expenditures by oil sands firms. In addition to operating expenditures discussed above, total investment can also include third-party companies involved in drilling, water treatment, engineering and design, transportation, welding, civil works, and pipelining, to name a few. In terms of scale, this spending was equivalent to about 4% of the Canadian economy in 2012.[14]

## North America is the largest source of oil sands investment

To deliver on oil sands production growth, significant amounts of capital are required. Owing to the scale of new investment (i.e., C$22 billion in 2012), funds from beyond Canada are a necessity. Foreign investment is not new to the Canadian oil and gas sector. For example, US-based investment contributed to the first large-scale discovery of crude oil in western Canada in 1947 as well as the first oil sands mining operation in 1967 and the first in-situ operation in 1985.[15]

In 2012, Canadians invested C$78 billion more abroad than they received in foreign direct investment (FDI).[16] Despite being net positive international investors, a number of high-profile acquisitions of Canadian oil sands companies have raised public concerns surrounding foreign ownership in the oil sands. Within the past five years (2008–12 inclusive) nearly US$27 billion in foreign acquisitions occurred in the oil sands.[17] Although this brings new capital to develop the oil sands, it has also heightened public concern over whether oil sands benefits will accrue to foreign interests ahead of Canadians.

IHS Herold tracks merger and acquisition activity in the energy sector, including the oil sands, and even considering recent offshore acquisitions, oil sands production remains largely a North American–based venture.[18] Figure 2 depicts the share of oil sands production in 2012 and, as projected by IHS, in 2020,

13. Oil sands supply includes SCO and bitumen blends.

14. Source: Statistics Canada, Gross domestic product, expenditure-based, provincial and territorial, current market prices, Table 384-0038, www5.statcan.gc.ca/cansim/pick-choisir?lang=eng&p2=33&id=3840038, accessed 19 November 2013.

15. Early exploration by Imperial Oil, a Canadian-based subsidiary of then Standard Oil (ExxonMobil today), was responsible for the discovery at Leduc No.1 well. The first large-scale commercial oil sands mining operation began operations in 1967 near Fort McMurray, Alberta, under the banner of the Great Canadian Oil Sands with the support of Sun Oil Company. Later in 1985 Imperial Oil established the first commercial in-situ oil sands project near Cold Lake, Alberta.

16. FDI occurs when individuals or businesses in one country buy businesses or expand existing operations in another company. FDI differs from indirect foreign investments, which include purchases of equity or debt that has little impact over the influence or control of business operations in the targeted nation. In 2012, inward FDI in Canada was C$634 billion and outward FDI was C$712 billion. Source: Department of Foreign Affairs, and Trade Development Canada, Foreign Direct Investment Statistics, www.international.gc.ca/economist-economiste/statistics-statistiques/investments-investissements.aspx, accessed 19 November 2013.

17. Includes 16 large transactions from companies headquartered in six nations. For acquisitions of companies that had assets beyond the oil sands, the non–oil sands assets were not differentiated from the total. One exception was Nexen Inc., where the value of the China National Offshore Oil Corporation transaction was weighted by the oil sands' share of Nexen's total reserves. Source: IHS Herold.

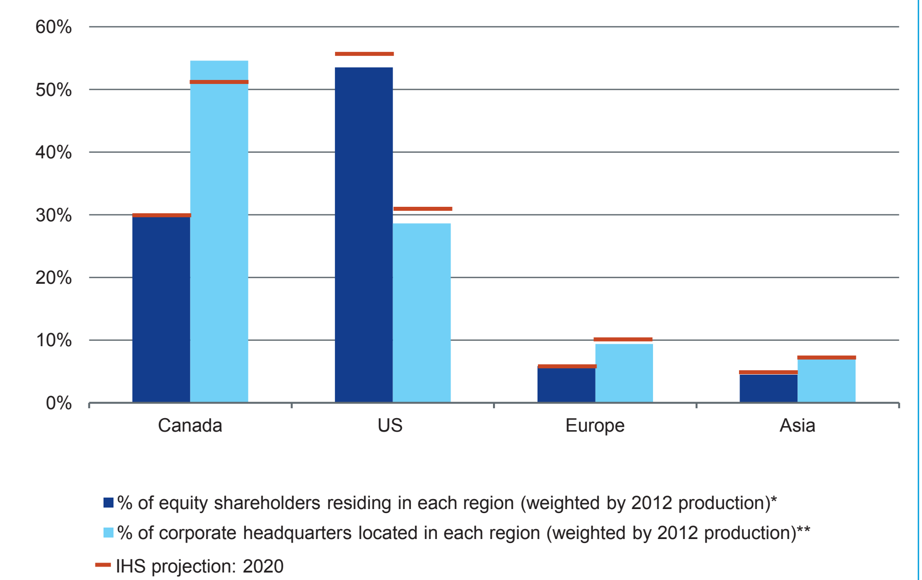
18. For more information on IHS Herold see: http://www.ihs.com/products/herold/index.aspx.

by both the location of corporate headquarters and the majority of equity shareholders.[19] In 2012, over 80% of oil sands production was controlled by firms headquartered in and backed by equity shareholders in North America. A closer look at North American ownership highlights the integrated nature of Canada and US investment. In 2012, 55% of oil sands production was controlled by firms headquartered in Canada with 30% of equity (weighted by production) held by Canadian interests. US citizens were the single largest investors in the oil sands, holding 54% of oil sands equity (weighted by production), and US-based corporations accounted for 29% of production. Looking at projects expected to come online between now and 2020, we expect production increases by North American firms to be balanced by offshore-based firms. Barring further, unseen, large-scale acquisitions of Canadian-based oil sands companies, we expect North American–based corporations and investors to maintain their dominant interest in oil sands production for the foreseeable future—beyond 2020.[20]

FIGURE 2

**Oil sands production weighted by shareholder equity ownership and corporate headquarter locations in 2012 and 2020**




*Results based on over 60% of outstanding share for the nine largest oil sands producers in 2012, weighted by IHS CERA estimate of raw bitumen production by company in 2012 and then in 2020. Projections for 2020 assumed shareholder and corporate ownership structure remained unchanged from today. Companies included in survey group collectively represented 85% of raw bitumen production in 2012 and 81% of expected production in 2020.
**Share of corporate headquarters in 2012 includes 26 active producers, which we defined as companies that averaged over 1,000 bd of raw bitumen production in 2012. Combined these companies accounted for 99.75% of bitumen production. Share of corporate headquarters in 2020 includes 35 companies that IHS CERA expects to be active producers. Combined we expect these companies to account for 99.91% of bitumen production in 2020.

Source: IHS Herold, IHS CERA, Bloomberg



## Foreign government–owned interests are a small share of oil sands production

There have been additional concerns in Canada about the role of foreign government–owned corporations, known as state-owned enterprises (SOEs), with particular attention being paid to Chinese SOEs.[21] However, China is not unique in having SOEs active in the oil sands. In 2012, SOEs from Japan, Norway, South Korea, and Thailand all had interests in the oil sands. Combined, all SOE interests, including Chinese, accounted for 6% of oil sands production in 2012. On their own, Chinese SOEs accounted for 5% of production.[22] Going forward, as a result of the stated policy of the Government of Canada to limit further acquisitions of controlling interests by SOEs in Canadian-based oil sands companies to "exceptional circumstances," we

19. Source: IHS CERA, IHS Herold, and Bloomberg. For more information see footnote for Figure 2.

20. Assuming ownership and shareholder structure in 2012 and IHS project level production outlook.

21. SOEs involved in oil production are also often referred to as national oil companies.

22. Source: IHS CERA.

expects future investments by national corporations to take the form of JVs, noncontrolling interests, and investments in non–Canadian-based oil sands businesses.[23]

23. Source: Prime Minister's Office (2012), "Statement by the Prime Minister of Canada on Foreign Investment," 7 December 2012, pm.gc.ca/eng/news/2012/12/07/statement-prime-minister-Canada-foreign-investment, accessed 19 November 2013.

# Part 2: Challenges in measuring economic benefits

It is generally accepted that oil sands development generates economic and employment benefits, and numerous studies, including this one, quantify them. However, there is some debate on the magnitude and geographical reach of the benefits. Limitations in current data and models contribute to this debate. The following section highlights a few areas of confusion in measuring economic benefits.

## Employment benefits—Greater than commonly used sources may indicate

The impacts of oil sands investment on the Canadian economy are greater than commonly used data sources may indicate. In the debate around the employment benefits associated with oil sands, two sets of numbers are often reported. One set represents direct jobs at oil sands companies—people who work at Suncor or Syncrude, for example. The other set comes from complex models of the economy, as we used for Part 3 of this report. These represent the total effect of employment associated with an investment in the economy—including the direct, indirect, and induced jobs across all sectors of the economy.

Employment numbers from these two sources differ because they measure different things. For example, using data from Statistics Canada, Canada's national statistical agency, oil sands companies directly employed around 18,000 people in 2012.[24] In a nation with about 15 million people employed, this is just over one-tenth of 1% of total Canadian employment in 2012.[25] However, employment impacts extend well beyond oil sands companies. Oil sands development relies on a multitude of industries, such as construction, engineering, geology, finance, manufacturing, environmental analysis, and hospitality, to maintain and grow production. For example, in 2012 work camp populations in the primary oil sands region had an estimated population of 39,000, an indication that employment impacts extend beyond oil sands firms.[26]

The only way to measure the broader employment impact of an investment, such as in oil sands, across the Canadian economy is to estimate it using sophisticated models of the economy. In Part 3 of this report we use one of these types of models, an input/output (I/O) model, to estimate the impact of oil sands investment on the Canadian economy. Across all sectors, and including direct, indirect, and induced employment, we estimate that oil sands investment contributed to 478,000 jobs in Canada in 2012. This is just over 3% of Canada's total employment—much larger than oil sands company-specific employment.[27]

The question of which employment number is best depends on what is being measured. If the question is how many people oil sands companies employ directly, Statistics Canada is likely the best source. However, if the question is about the total effect of oil sands investment on employment in Canada, then a picture that includes the broader employment impacts on the economy is more appropriate.

24. Industrial statistics reported by Statistics Canada are compiled according to the North American Industry Classification System (NAICS). Employment statistics for oil sands development are reported as part of the broader oil and gas sector (NAICS 211). However, GDP is available at a more detailed level, including "non-conventional oil extraction"—principally oil sands (NAICS 211114). Weighting employment by oil sands' share of oil and gas GDP provides an estimate of 17,676 full-time positions in 2012. Source: Statistics Canada, Survey of Employment, Payrolls and Hours, Table 281-0024, www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2810024, accessed 19 November 2013. Statistics Canada, Gross domestic product (GDP) at basic prices, by NAICS, 2012l Estimate, Table 379-0031, www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=3790031, accessed 19 November 2013.

25. This includes all employees, salaried employees paid a fixed salary, and employees paid by the hour. Source: Statistics Canada, Survey of Employment, Payrolls and Hours, Table 281-0024, www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2810024, accessed 19 November 2013.

26. Source: Regional Municipality of Wood Buffalo, Municipal Census 2012, www.woodbuffalo.ab.ca/Municipal-Government/Municipal-Census.htm, accessed 31 July 2013.

27. Statistics Canada, Survey of Employment, Payrolls and Hours, Table 281-0024, www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2810024, accessed 19 November 2013.

## Benefits beyond Alberta are larger than estimates

The estimates of how the economic benefits of oil sands development are shared across Canada and beyond, including the United States, attribute too much of the benefit to Alberta and too little to other regions. Studies using I/O models, including this report, typically attribute greater than 85% of the economic benefit (as measured by GDP) of oil sands developments to Alberta.[28] In our report we estimate that of the C$91 billion oil sands contributed to Canadian GDP in 2012, only C$12 billion of this benefit occurred beyond Alberta (see Part 3). This result is driven in part because, like other studies in this area, ours lacked comprehensive data on the geographic distribution of direct oil sands investment. For example, not all equipment manufacturing or engineering takes place in Alberta; some is done elsewhere in Canada or is imported. The problem is the lack of comprehensive data on such non-Alberta investments. Because of this lack of data, we assumed that all direct spending occurred in the province. As a result, the I/O model allocates all the direct benefit associated with oil sands development to Alberta. Any direct benefits that may be occurring in other regions are therefore not accounted for appropriately.

Although comprehensive data do not exist, oil sands companies are making large direct investments beyond Alberta. For example, in 2011, Suncor reported spending C$1.6 billion in Ontario and Quebec, and Syncrude Canada spent over C$1 billion in Canadian regions other than Alberta. In the same year, Canadian Natural Resources Ltd (CNRL) spent C$770 million at 350 Ontario companies in support of a new oil sands facility called Horizon.[29] There are also other examples of direct spending in the United States. One example is of the impact of oil sands companies' purchases from a US supplier of steam boilers, resulting in expansion of the manufacturer's facilities in the United States.[30]

Spending patterns can also change over time. For instance, as oil sands activity expands, more direct investment could occur in other regions. In the absence of these data, too much of the investment and therefore the economic benefit is attributed to Alberta and too little to the rest of Canada and beyond.

Another factor that can bias estimates is the static nature of typical I/O models. In the real world, the economy will evolve and change as it reacts to impacts such as local cost inflation or regional shortages, or as production methods become more efficient. The I/O model's static assumptions do not adjust for these changes. As a result, the size and distribution of future benefits across regions can be less certain than estimates of the current level of benefits. This is discussed in more detail in the box "Using input/output models to estimate economic impacts of oil sands development."

28. Based on work by IHS CERA and IHS Global Insight.

29. Source: Oil Sands Question and Response (OSQAR) Blog, "Are oil sands opponents tilting at windmills?" 6 June 2012, http://osqar.suncor.com/2012/06/are-oil-sands-opponents-tilting-at-windmills.html#more, accessed 11 July 2013. Source: Syncrude Canada, Syncrude Sustainability Report, http://syncrudesustainability.com/2011/economic#operational_economic_economic-contribution, accessed 27 August 2013. Source: CAPP, "The Oil Sands: Growing Ontario's Economy," http://www.capp.ca/GetDoc.aspx?DocID=176826, accessed 9 July 2013.

30. Source: JournalStar.com, "Oil sands demand will expand Cleaver-Brooks in Lincoln," http://journalstar.com/business/local/cleaver-brooks-to-expand-lincoln-plant/article_fa2dd8b7-f60d-5d6c-89af-a4e3dc7bbc98.html, accessed 15 November 2013.

## Using input/output models to estimate economic impacts of oil sands development

A well-known approach to quantifying the economywide impacts from a large investment like the oil sands is with social accounting models. A common version of these models is the input/output or I/O model.

I/O models are useful policy tools for measuring the effect of an investment or an increase in spending on the economy because they can capture the total effect on the economy: the direct, indirect, and induced impacts. These models are best suited to measuring marginal impacts (such as the impact of a relatively small investment for a short period) but can provide illustrative estimates of impacts of a large, sustained investment like the oil sands across an economy. I/O models are data intensive, requiring information from across an economy. I/O models have been around for nearly three-quarters of a century, and their structure and principles are well understood. However, all models hinge on their assumptions, which include not only data fed to them but also how the models themselves are constructed.

All economic benefit results should be interpreted as estimates; measuring an economy as diverse as Canada is a complex undertaking. Below we discuss some limitations or implications of the structure of the typical I/O model, such as we used in Part 3.

**Impact of key I/O model assumptions on our results**

I/O models are constructed with fixed assumptions about the economy based on what we know today. Over time these assumptions can become out of step with the real world as the economy evolves. This can occur more rapidly for larger investments like the oil sands, as they have a more pronounced impact on the economy. This requires that models are updated regularly; however, when the models are used to make projections, they are based on today's environment, which cannot fully anticipate how the economy may change over time.

Key assumptions behind I/O models are fixed prices and a fixed ratio of inputs to outputs. This means in an I/O framework there is no scarcity and no inflation. So as production ramps up, there are infinite inputs available for production at the same price. In reality, an increase in demand for goods and services can lead to higher prices as the goods in demand become harder to find or more scarce. Larger projects, like the oil sands, are more likely to lead to price increases. In fact, this dynamic has occurred in the oil sands. Prior to the recession, oil sands developers faced labor inflation that at times exceeded 8% per year, and although cost increases subsided during the recession, by 2012 cost inflation was around 5% per year.* Given that I/O models do not incorporate the effects of price inflation or scarcity, there is less certainty surrounding future estimates of benefits and the allocation of benefits across regions. This is discussed in more detail below.

- **Uncertainty of future benefit estimates.** Outlooks and projections are predicated on what we know today. However, economies evolve, and the more distant the outlook, the less certain estimates become. This is true of all outlooks. However, there are specific uncertainties associated with estimating future benefits using I/O models. A key issue is the absence of price inflation from the model. Inflation can contribute to higher production costs. As things get more costly, production economics weaken, and over time the level of production and the associated

*IHS North America Crude Oil Markets: Canadian Fundamentals Data tracks the cost of building oil sands projects. For more information see: www.ihs.com/oilsands. IHS Capital Costs Forum also maintains industry-specific cost escalation information. For more information see www.ihsindexes.com. For more information on our cost escalation assumptions see footnote for Table 1.

## Using input/output models to estimate economic impacts of oil sands development (continued)

economic benefit can be lower than an I/O model would normally predict. I/O models also preclude the potential for efficiency improvements from economies of scale, learning by doing, and technological change over time. Efficiency improvements can work in the opposite direction as inflation, because they can lower production costs. Lower costs can encourage growth, which over time can contribute to higher production and the associated economic benefit. This too would not be captured by the typical I/O model. Although there are factors that can both overestimate and underestimate the benefits, there is a greater potential toward overestimation. For these reasons, the more near term an I/O model estimate is, the more certain it will be.

- **Misallocation of the estimate of the benefits among regions.** Price inflation can also encourage producers to outsource work to lower-cost regions. With demand from oil sands investment exceeding local capacity, more design, engineering, manufacturing, and even prefabrication of modules has moved beyond Alberta. This includes investment in other Canadian regions, the United States, and beyond. This effect is also not captured by the typical I/O model.

### More-complex models can overcome the shortcomings of I/O models

To overcome the shortcomings of the typical I/O model, more powerful estimating tools can be deployed that allow price and production inputs to fluctuate. This type of model may also allow for the measurement of potential crowding-out effects, which have been expressed in the debate around oil sands development and which cannot be captured by the typical I/O model. However, greater precision requires more data, computational complexity, and assumptions. For example, to incorporate technological change, a whole range of new questions must be answered and imputed into the model, such as at what rate should technology reduce costs, how much should technology cost, and should technology evolve at a fixed rate or differently for different industries. Likewise, to improve the understanding of regional impacts, a geographic understanding of oil sands spending is required. This level of analysis would be a very large undertaking, requiring extensive data, consultation, and an intensive review of a plethora of assumptions.. However, given the anticipated scale of development planned and the debate over the level of economic benefits to Canada, further analysis is warranted.

# Part 3: Economic benefits today and in the future

This section provides estimates of GDP, employment, and government revenue to help quantify the economic impact of oil sands development on Canada's economy today and in 2025. The section is divided into two parts: first we outline the methodology and key assumptions behind our analysis and then present our results. More detailed results are available in the appendixes.

## Methodology and assumptions

As discussed in Part 2, IHS Global Insight in collaboration with IHS CERA estimated the total effect of oil sands investment on the Canadian economy (including the direct, indirect, and induced effects). Our estimates compare the annual benefits from oil sands in 2012 and in 2025. The benefits are not cumulative summations of future potential benefits; rather they are a snapshot in time of potential annual flows. We chose to present annual estimates, as opposed to summations of multiple years of benefits, since annual estimates provide more context to the change in benefits. It is important to acknowledge that production from an oil sands facility can provide multiple decades of revenue and economic benefit. In fact, with ongoing investment, some facilities are expected to operate for more than 40 years.

Our analysis used the latest version of Statistics Canada's interprovincial input/output model, updated in 2013, to more accurately measure the effects of oil sands development on the Canadian economy.[31]

What follows is a brief description of the assumptions that underlie our estimate of the economic benefits from oil sands in 2012 and 2025. A summary of the key assumptions for each scenario is presented in Table 1.

- **2012 estimates.** In 2012, oil sands production reached nearly 1.8 mbd, which generated about C$63 billion in gross revenues (see in Figure 1). We estimated C$41 billion of direct capital was invested in 2012. This number differs from what we show in Figure 1 because it includes only the operating costs to extract bitumen and new capital project spending. Other spending such as general and administrative expenses that are included in total investment in Figure 1 are estimated as an output of the I/O model.[32]

TABLE 1

**Key scenario assumptions**

| | 2012 | 2025 |
|---|---|---|
| Production (barrels per day) | | |
| Synthetic + nonupgraded bitumen | 1,772,976 | 3,751,160 |
| Gross revenues (billions of constant $2012) | | |
| Gross revenue from oil sands production | $63 | $136 |
| Expenditures (billions of constant $2012)[1] | | |
| New capital project expenditures | $21 | $15 |
| Operating expenditures (for extraction only) | $20 | $41 |

1. New capital expenditure estimate based on per-barrel costs of production for mining, in-situ and upgrading derived from the IHS North America Crude Oil Markets Service. Operating or sustaining capital expenditure includes separate costs for mining sustaining capital, mining turnaround capital, in-situ sustaining capital, in-situ turnaround capital, upgrader sustaining, and turnaround capital. Expenditures included cost estimates on a range of expenditures, including overburden removal and site clearing, mine equipment, drilling, process equipment (i.e., vessels and towards, exchangers, compressors, and pumps), solids handling equipment, labor (skilled and nonskilled), steel and pipe, construction and civil works, engineering and project management, electrical and instrumentation (i.e., electrical bulks, electrical equipment, and control systems), transportation (truck hauling), and contingency/risk. For more information on the IHS North America Crude Oil Markets see www.ihs.com/oilsands.

Source: IHS CERA. Production and price outlook based on IHS CERA Planning Scenario outlook. For more information see: IHS Global Scenarios, http://www.ihs.com/products/global-scenarios/energy.aspx. Expenditures used capital cost assumptions from IHS North America Crude Oil Markets: Canadian Fundamentals and IHS Capital Costs Forum. For more information see: www.ihs.com/oilsands and www.ihsindexes.com. © 2013 IHS

31. In 2013, Statistic's Canada updated its I/O model to differentiate the unconventional oil and gas subsectors from the broader oil and gas sector. The current version of Statistics Canada's model includes data up to 2009 and features 234 business or industrial sectors from across 14 regions of Canada, as well as trade balances. For more information on the Statistic's Canada Interprovincial Input-Output Model Simulations see: **www5.statcan.gc.ca/bsolc/olc-cel/olc-cel?lang=eng&catno=15F0009X.**

32. Estimates of oil sands capital costs are based on production levels and capital cost estimates from the IHS North America Crude Oil Markets service. For more information see footnote for Table 1.

- **2025 estimates.** The IHS CERA planning scenario was used for production and price outlook assumptions.[33] Using this scenario, oil sands production more than doubles from 1.8 mbd in 2012 to nearly 3.8 mbd in 2025. On a cumulative basis from 2012 to 2025, the scale of the build-out required to achieve this level of production would require an investment of over one-quarter of a trillion dollars. For 2025 new and operating expenditures are estimated at C$56 billion and annual oil sands revenues at C$136 billion. To reduce the potential for overestimation of the future economic benefit in 2025 (as outlined in Part 2, the box "Using input/output models to estimate economic impacts of oil sands development"), our outlook for oil sands–specific cost inflation was incorporated into our capital costs estimates. We expect between 2012 and 2025, on average, a 1.9% annual rate of oil sands capital costs escalation (above the economywide rate).[34] No one knows exactly how the economy (or oil sands inflation) will ultimately develop. However, there is more certainty in predicting these factors over the next decade (the scope of our outlook) than over longer time frames.

In the next section, all results show the total effect of the economic benefits from oil sands today and in 2025. More detailed results, including the breakout of benefits by type (direct, indirect, and induced) and by region, are available in Appendixes 1 and 2.

## Oil sands are already a major contributor to Canadian economy

Often, the economic benefits of oil sands are depicted as a future aspiration; however, our results, as shown in Figure 3, demonstrate that in 2012 oil sands already made a significant contribution to Canada's economy, as measured by GDP, employment, and government revenues.

In terms of scale, for GDP and employment, the most commonly used indicators of economic benefit, oil sands contributed C$91 billion to Canadian GDP and 478,000 jobs in Canada in 2012. This is equivalent to 5% of Canadian GDP and 3% of total employment in Canada.[35] For comparison, the GDP benefit is greater than 6 out of 10 Canadian provinces, and the

FIGURE 3

**Oil sands economic benefits in 2012 and 2025**

| | Today's benefits in 2012 1.8 mbd | Potential benefits in 2025 3.8 mbd | Future benefits compared with today (2025 less 2012) |
|---|---|---|---|
| GDP | $91 billion | $171 billion | $80 billion more |
| Jobs | 478,000 | 753,000 | 275,000 more jobs |
| Taxes and royalties | $28 billion | $61 billion | $33 billion more |

30904-2

Note: All prices in Canadian 2012 dollars. Values include the total effect of oil sands investment on the Canadian economy; they include the direct, indirect, and induced effects. For more details see Appendix 1 and 2.

Source: IHS CERA



33. IHS maintains long-term and short-term global and energy planning scenarios that include capital costs and energy price projections. For more information see IHS Global Scenarios, http://www.ihs.com/products/global-scenarios/energy.aspx.

34. Capital costs estimates are based on production from the IHS Global Scenarios planning scenario adjusted for oil sands–specific cost escalation from the IHS North America Crude Oil Markets. Oil sands–specific cost escalations incorporated into capital costs are more pronounced in the early years, tapering off as production moves over time toward in-situ development, which lowers the demand for labor and reduces the rate of escalation. For more information see footnote for Table 1.

35. Source: IHS CERA. Statistics Canada, Gross domestic product, expenditure-based, provincial and territorial, current market prices, Table 384-0038, www5.statcan.gc.ca/cansim/pick-choisir?lang=eng&p2=33&id=3840038, accessed 19 November 2013. Statistics Canada, Survey of Employment, Payrolls and Hours, Table 281-0024, www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2810024, accessed 19 November 2013.

employment contribution is on a scale greater than 5 out of 10 Canadian provinces. Together this is on a scale greater than the fifth largest provincial economy in Canada—the Province of Saskatchewan.[36]

Other indicators, such as transfers to governments in the form of taxes and royalties, were also large. Together, government revenues, including federal and provincial corporate, consumption, and personal income tax, from the total effect of oil sands investment (across all sectors including direct, indirect, and induced) of the Canadian economy amounted to C$28 billion. Government revenues break down as follows:

- **Federal government, C$15 billion in tax revenue.** The Government of Canada received an estimated $15 billion as a result of the total effect of oil sands development in 2012. This was 6% of the federal revenues in federal tax year 2011–12.[37] This share of federal revenues equates to about C$437 per Canadian and in the federal fiscal budget period 2011/12 was nearly equivalent to federal spending on unemployment insurance or to half of what the federal government spent on health care transfers to provincial and territorial governments.[38]

- **Alberta, C$7.7 billion in tax revenue and C$4 billion in royalties.** The Government of Alberta was the second largest tax recipient. Including royalties, Alberta received nearly C$12 billion in 2012. This constituted almost one-third of Alberta government revenues in 2012.[39] This income was more than Alberta's total spending on all levels of education (K-12, adult education, and post-secondary), infrastructure, and transportation—or about three-quarters of what the government spent on health services.[40]

- **Other provinces, $1.3 billion in tax revenues.** Other provinces received C$1.3 billion in revenues from the total effect of oil sands development on the Canadian economy. As discussed previously, it is likely that this value is underestimated owing to data limitation, while the Alberta revenues are overestimated.

## Oil sands development contributes to economies beyond Canada

Economic benefits associated with oil sands development can reach beyond Canada by generating demand for goods and services from other nations. The United States is Canada's largest trading partner and vice versa. The two economies are highly integrated. In 2012, the United States accounted for 51% of all goods and services, not just oil, imported to Canada and received 75% of all Canadian exports.[41] Conversely 14% of all goods and services imported to the United States came from Canada, and 16% of all US exports went to Canada.[42] In our model, we estimate that when the total effect is considered, oil sands investment resulted in the import of C$16 billion worth of goods and services from other countries. This was equivalent to 3.5%

36. In 2012, estimated GDP impact of oil sands was greater than six provinces and three territories in Canada. Estimated employment impact was greater than five provinces and three territories in Canada that year.

37. Total federal revenues in tax year 2011–12 were C$245 billion. Source: Finance Canada (2012), "Annual Financial Report of the Government of Canada: Fiscal Year 2011-2012," Table 1, http://www.fin.gc.ca/afr-rfa/2012/report-rapport-eng.asp, accessed 29 December 2013.

38. In fiscal year 2011/12 the Canadian federal government spent C$17.6 billion on unemployment insurance and C$27.2 billion on health care transfers to provincial and territorial governments. Source: Department of Finance Canada, (2012), "Your Tax Dollar," www.fin.gc.ca/tax-impot/2012/2012-eng.pdf,accessed 18 June 2013. Source: Statistics Canada, Estimates of population, Canada, provinces and territories, Annual 2012 Estimate, Table 051-0005, www5.statcan.gc.ca/cansim/a05?lang=eng&id=0510005, accessed 29 August 2013.

39. In Budget 2012, Alberta revenues were C$40 billion. Source: Government of Alberta, Budget 2012, budget2012.alberta.ca/highlights, accessed 31 July 2013.

40. In 2012, Alberta planned to spend over C$17 billion on health and wellness and C$11.5 billion on "Securing Alberta's Economic Future," which included education, finance, infrastructure, transport, and other operating expenses. Source: Government of Alberta, Budget 2012, 3rd Quarter Supplementary Estimates, http://www.finance.alberta.ca/publications/budget/budget2012/fiscal-plan-overview.pdf,accessed 16 July 2013.

41. Source: Industry Canada, Import, Export and Investment, 2012 Total Imports and Total Exports by Specific Country, https://www.ic.gc.ca/eic/site/icgc.nsf/eng/h_07052.html, accessed 9 December 2013.

42. Source: US Census Bureau, "U.S. Goods Trade: Imports & Exports by Related Parties, 2012," http://www.census.gov/foreign-trade/Press-Release/2012pr/aip/related_party/, accessed 9 December 2013.

of total Canadian imports in 2012.[43] By 2025, the total effect of oil sands investment could demand C$25 billion in imports.[44]

### Oil sands economic benefits in 2025 could nearly double today's level

In a future where oil sands grow as anticipated, reaching 3.8 mbd in 2025, the economic benefits in terms of GDP and government revenues could be nearly double the current level (as shown in Figure 3). Oil sands' contribution to jobs could also be over 50% higher.

- **GDP.** Oil sands' contribution to Canadian GDP could reach $171 billion in 2025—just shy of double today's level. This would be like adding another economy the size of Saskatchewan today to the Canadian economy by 2025.[45]

- **Employment.** Between 2012 and 2025, the total effect of oil sands investment alone across all sectors of the Canadian economy could add over one-quarter of a million more jobs. By 2025, oil sands' total contribution to employment in Canada could reach 753,000 jobs. This is comparable with 5% of total employment in Canada in 2012 and would be on a scale equivalent to nearly half of all the people working in Canada's health care service sector today.[46]

- **Taxes and royalties.** Government revenues from the total effect of oil sands investment in Canada could nearly double what they are today, moving from C$28 billion to C$61 billion in 2025—the federal share of this being C$28 billion in 2025, and roughly equivalent to federal spending on health care transfers to provinces in 2012.[47] The Alberta government's share of taxes and royalties from oil sands is estimated at C$31 billion in 2025, with about C$16 billion from royalties. For reasons discussed in Part 2, it is likely that the nonroyalty share of Alberta government revenues is overestimated at the expense of the estimate to other regions.

43. Source: IHS Global Insight and Statistics Canada.

44. In the growth scenario, direct and indirect oil sands investment results in oil sands–related imports worth $18.5 billion and induced imports of C$7 billion.

45. Statistics Canada, Gross domestic product, expenditure-based, provincial and territorial, current market prices, Table 384-0038, www5.statcan.gc.ca/cansim/pick-choisir?lang=eng&p2=33&id=3840038, accessed 19 November 2013.

46. Source: Statistics Canada, Survey of Employment, Payrolls and Hours, Table 281-0024, www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=2810024, accessed 19 November 2013.

47. Federal Health Care Transfers was C$27.2 billion in 2012. Source: Department of Finance Canada, (2012), "Your Tax Dollar," www.fin.gc.ca/tax-impot/2012/2012-eng.pdf,18 June 2013.

## Conclusion: Greater economic benefits are possible in the future

The oil sands are already an economic engine for Canada. In 2012, C$73 billion was invested in maintaining and growing oil sands production. This was more than the industry made in generating $63 billion in gross revenues. Of the money the industry made, most of these funds remained within the oil sands. Four-fifths was reinvested into maintaining production, and another 10% went to the Canadian government for royalties and taxes.

Oil sands benefit to Canada exceeds the direct capital invested. Each dollar invested in oil sands spurs additional spending in other sectors of the economy and as employee wages are spent. As a result, considering only the direct impacts to the economy is an incomplete measure of the total benefits. We estimate that in 2012 the total effect of oil sands development contributed 478,000 jobs and C$91 billion to GDP in Canada. This is approximately equivalent to 3% of total employment and 5% of Canadian GDP in 2012. Greater potential benefits exist. In a future where oil sands production reaches 3.8 mbd in 2025, the benefit in terms of GDP could be nearly two times greater than today.

The collective understanding of the full extent of the future potential benefits of oil sands to the Canadian economy is not complete. Current data and models make future benefits estimates less certain and at the same time can misallocate benefits between regions—attributing too little of the benefit to other regions of Canada (or even beyond). What is needed is a more complete understanding of oil sands investment, including more powerful models and more detailed data. These models would include the ability to measure concerns that oil sands growth (and the resulting inflation and currency impacts) could affect investment elsewhere in the economy. Given the importance of oil sands to Canada's economy—both today and the future potential—and the ongoing debate surrounding oil sands economic benefits, more research is warranted.

# Appendix

TABLE A-1

**Model results: Economic effect Canada-wide and on Alberta**
(Results should be interpreted as annual contribution in the year reported. Where applicable all dollars in billions of 2012 constant CDN).

| | 2012 | | 2025 | |
|---|---|---|---|---|
| | Direct + indirect | Total effect[1] | Direct + indirect | Total effect[1] |
| **Gross/total effect on Canada** | | | | |
| GDP | $76,888 | $91,197 | $147,658 | $171,076 |
| Jobs | 352,239 | 478,440 | 546,053 | 752,987 |
| Taxes | $24,123 | $28,323 | $54,416 | $61,300 |
| Federal | $12,524 | $15,241 | $23,766 | $28,211 |
| Provincial | $7,570 | $9,053 | $14,533 | $16,972 |
| Royalties | $4,029 | $4,029 | $16,117 | $16,117 |
| **Total economic effect on Alberta only** | | | | |
| GDP | $69,710 | $78,941 | $134,965 | $149,846 |
| Jobs | 276,844 | 348,898 | 413,342 | 529,502 |
| Taxes | $22,201 | $24,897 | $51,019 | $55,364 |
| Federal | $11,331 | $13,161 | $21,651 | $24,600 |
| Provincial | $6,841 | $7,708 | $13,251 | $14,648 |
| Royalties | $4,029 | $4,029 | $16,117 | $16,117 |

1. Total benefit is also defined as upper bound in the report and includes the total effect from the direct, indirect, and induced activity from oil sands investment in the given year.

Source: IHS CERA, IHS Herold, and Government of Alberta

TABLE A-2

**Model results: Economic effect on Canadian regions**
(Results should be interpreted as annual contribution in the year reported. Where applicable all dollars in billions of 2012 constant CDN).

| | 2012 | | 2025 | |
|---|---|---|---|---|
| | Direct + indirect | Total effect[1] | Direct + indirect | Total effect[1] |
| **British Columbia** | | | | |
| GDP | $1,367 | $2,411 | $2,476 | $4,218 |
| Jobs | 14,383 | 26,605 | 25,147 | 45,409 |
| Provincial taxes | $116 | $218 | $212 | $383 |
| **Saskatchewan** | | | | |
| GDP | $662 | $944 | $1,032 | $1,486 |
| Jobs | 5,169 | 7,894 | 8,189 | 12,586 |
| Provincial taxes | $84 | $121 | $130 | $190 |
| **Manitoba** | | | | |
| GDP | $285 | $494 | $495 | $843 |
| Jobs | 3,484 | 6,007 | 6,022 | 10,204 |
| Provincial taxes | $25 | $48 | $44 | $81 |
| **Ontario** | | | | |
| GDP | $3,597 | $6,122 | $6,487 | $10,770 |
| Jobs | 38,356 | 63,821 | 68,856 | 111,988 |
| Provincial taxes | $322 | $609 | $581 | $1,072 |
| **Quebec** | | | | |
| GDP | $1,042 | $1,903 | $1,804 | $3,246 |
| Jobs | 11,443 | 20,829 | 19,878 | 35,606 |
| Provincial taxes | $158 | $304 | $275 | $519 |
| **Atlantic Canada[2]** | | | | |
| GDP | $190 | $332 | $335 | $575 |
| Jobs | 2,258 | 3,932 | 4,059 | 6,877 |
| Provincial taxes | $22 | $43 | $39 | $75 |
| **Northern Territories[3]** | | | | |
| GDP | $34 | $51 | $63 | $93 |
| Jobs | 302 | 453 | 562 | 816 |
| Provincial taxes | $1 | $2 | $3 | $4 |

1. Total benefit is also defined as upper bound in the report and includes the total effect from the direct, indirect, and induced activity from oil sands investment in the given year.
2. New Brunswick, Prince Edward Island, Nova Scotia, and Newfoundland and Labrador.
3. Northwest Territories, Nunavut, and Yukon.

Source: IHS CERA, IHS Global Insight

## Report participants and reviewers

IHS CERA hosted a focus group meeting in Calgary, Alberta (6 June 2013), providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the potential economic benefits from oil sands development. 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

Alberta Innovates, Energy and Environmental Solutions

Alberta School of Business, University of Alberta

American Petroleum Institute

BP Canada

Canadian Association of Petroleum Producers

Canadian Oil Sands Limited

Cenovus Energy Inc.

Conoco Philips Company

Canadian Natural Resources Ltd.

IBM Canada

Imperial Oil Ltd.

In Situ Oil Sands Alliance

Mowat Centre, School of Public Policy and Government, University of Toronto

Natural Resources Canada

Nexen Energy ULC

School of Public Policy, University of Calgary

Shell Canada

Statoil Canada Ltd.

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

# IHS team

**MOHSEN BONAKDARPOUR,** Managing Director, IHS Energy Insight, is responsible for directing advisory projects and industry analysis product development in the Economic and Public Sector Consulting practice of IHS Global Insight. Mr. Bonakdarpour has more than 25 years of experience in energy, global industry, and macroeconomic analysis. He has worked with a wide range of clients, helping them to size their markets, predict product demand, and better target their marketing efforts. Before joining IHS, he worked at PNR & Associates and at the Center for Social Policy and Community Development. Mr. Bonakdarpour holds a Bachelor of Science and a Master of Arts from Temple University.

**JACKIE FORREST,** Senior Director, IHS Energy Insight, leads the North American Crude Oil Markets service with IHS and heads the research effort for the IHS CERA Oil Sands Energy Dialogue. She actively monitors emerging strategic trends related to oil sands and heavy oil, including capital projects, economics, policy, environment, and markets. Recent contributions to oil sands research include reports on the life-cycle emissions from crude oil, the impacts of low-carbon fuel standards, effects of US policy on oil sands, and future markets for Canadian oil sands. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**KEVIN BIRN,** Associate Director, IHS Energy Insight, is the principal researcher for the IHS CERA Oil Sands Energy Dialogue. Recent contributions to oil sands research include analysis of the marine transport of oil sands crude, upgrading economics, and the future markets for oil sands. Prior to joining IHS, Mr. Birn worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada, helping to inform early Canadian oil sands policy. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US Secretary of Energy. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta.

**MIHAELA SOLCAN,** Consultant, IHS Energy Insight, is with the Economic Impact Analysis group at IHS Global Insight. Her main areas of expertise are in applied macroeconomics and econometrics, and her background is in quantitative modeling and economic analysis. At IHS she has worked on a wide array of projects, including a recent project with an international manufacturing company to project sales and revenue growth for select industries, and building a comprehensive macroeconomic model to develop and formulate energy policy for an Asian country which encompassed all relevant sectors of the economy. Prior to joining IHS, Ms. Solcan was a teaching assistant and a research fellow at the Department of Economics at the University of Delaware. She holds a Bachelor of Science from the University of Lyon, France, and a PhD from the University of Delaware.

IHS ENERGY

# Oil Sands Cost and Competitiveness

December 2015

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**STRATEGIC REPORT**

Canadian Oil Sands Dialogue | Special Report

**Kevin Birn**
Director, IHS Energy

**Jeff Meyer**
Associate Director, IHS Energy

# Contents

# Oil Sands Cost and Competitiveness

## Key implications

Over the past 15 years, the Canadian oil sands has been a pillar of global supply growth. Yet growth did not occur without challenges. One of these challenges was rising development costs. The 2014–15 oil price collapse poses a fresh challenge for continued growth in the Canadian oil sands. This report looks back at historical costs and assesses what these trends and a changing business environment mean for the competitiveness of oil sands investment.

- **As output grew, the cost to construct new projects appreciated—indeed, cost challenges were partly a product of the industry's success—rising over 70% from 2000 to 2014.** In the early 2000s, oil sands projects were truly greenfield. Many projects were first-of-a-kind, access to labor and services was limited, and the oil sands region lacked sufficient infrastructure such as roads and power lines, which pushed up development costs.

- **Regional competition for skilled labor was a key factor behind historical capital cost escalation.** Labor cost—a function of wage and productivity—is the single largest input to construct an oil sands facility and also influences the cost of other key regional inputs. Stiff competition for workers—a product of the scale of labor demands—helped drive labor costs higher, contributing to overall project cost escalation.

- **Nonetheless, even prior to the 2014–15 price collapse, cost pressures appeared to be moderating owing to both local and international factors.** Major input cost pressures subsided in recent years. Fabrication yard capacity expanded, global steel prices softened, and oil sands companies realized the need to better manage cost pressures.

- **Lower oil prices are poised to reset costs globally, and the oil sands competitive position may shift.** Prior to the price collapse, oil sands projects were competitive with other growth opportunities around the world in the mid to high range of the cost spectrum. Oil sands costs are declining, but it is unclear how the oil sands—along with other large capital projects—will fare in terms of costs and margins in a post–price collapse world.

- **The oil sands of tomorrow will be different from the past, which may provide an opportunity to keep future cost pressures in check.** The investment ecosystem has benefited from the expansion of the regional infrastructure, the service sector, and the labor market since the early 2000s. Lower oil prices are lowering investment but also lowering capital and operating costs. Small-scale brownfield expansions—which require less labor, investment, time, and capital—will drive future growth.

—December 2015

 

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# Oil Sands Cost and Competitiveness

**Kevin Birn,** Director, IHS Energy[1]
**Jeff Meyer,** Associate Director, IHS Energy

## About this report

**Purpose.** Over the past 15 years, costs in the Canadian oil sands rose steadily. This was not isolated to the oil sands; oil production costs increased around the world. Yet, cost escalation in the oil sands was considered particularly acute. In the run-up to the 2014 oil price collapse, questions were being raised about the industry's long-term competitiveness in light of this historical trend. This report looks back at historical costs in the oil sands and assesses what these trends and a changing business environment mean for the competitiveness of oil sands investment in the future.

**Context.** This report is part of a series of reports from the IHS Canadian Oil Sands Energy Dialogue. The Dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Participants include representatives from governments, regulators, the oil and gas industry, academics, pipeline operators, refiners, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by a multistakeholder survey; a workshop held in Calgary, Alberta, on 23 October 2014; and participant feedback on a draft version of the report. IHS has full editorial control over this report and is solely responsible for the report's content (see the end of the report for a list of participants and the IHS team).

**Structure.** This report has five parts and an appendix:

- Introduction: Growth, costs, and the future
- The unconventional oil sands
- Understanding oil sands costs: History and current environment
- Oil sands competitiveness
- Conclusion: Toward a globally competitive industry
- Appendix: Oil sands' history of capital cost escalation in detail

1. With special thanks to Carmen Velasquez, former Director at IHS Energy and currently Executive Director for Energy Programs at the University of Alberta School of Business.

## Introduction: Growth, costs, and the future

From 2000 to 2014, Canadian oil sands production more than tripled, from about 600,000 b/d to over 2.2 MMb/d. As investment increased, costs escalated—sometimes dramatically. Indeed, this issue was not isolated to the oil sands or Canada. The cost of new projects rose globally over most of this period. But for the oil sands, rising costs had a pronounced impact on the price tag of new projects. IHS estimates that from 2000 to 2014 the cost for new projects increased over 70%. That means a project that cost $2.5 billion in 2000 would cost over $4.2 billion in 2014.[2]

At the same time, western Canadian producers suffered from constrained pipeline takeaway capacity that, at times, reduced the price that producers were able to obtain for their oil. In the run-up to the 2014 price collapse, concern about escalating costs was raising questions about the viability of future projects and oil sands' ability to compete with new supply sources globally.

A much lower oil price environment poses a fresh challenge for Canadian oil sands growth. Planned capital expenditures in new projects have been cut and cut again. However, projects under construction prior to the price collapse are expected to come online and ensure that oil sands output will rise through the end of the decade—up from about 2.3 MMb/d in 2015 to over 3 MMb/d by 2020.

Yet, as these projects under construction are completed, construction activity is slowing, and cost pressures are easing. Globally, oil field development costs are poised to reset at a lower level. Shifting global cost structures could have an impact on the relative competitive position of oil sands. Moreover, the prospects of changes to fiscal terms and more stringent carbon policies have moved up the list of challenges that could affect industry competitiveness. Will the oil sands industry be able to achieve similar cost reductions as their global peers? Will oil sands' history of cost appreciation return with higher oil prices? And what will the impact be on oil sands competitiveness and future growth?

This report explores oil sands costs and competitiveness—past, present, and future. It includes a review of oil sands economics, history of capital cost escalation, and how the industry may be at a turning point in future cost escalation. The report concludes with a discussion about how lower prices may shift the oil sands, relative competitive position in the world.

There are five sections and an appendix.

- Introduction: Growth, costs, and the future
- The unconventional Canadian oil sands
- Understanding oil sands costs: History and current events
- Oil sands competitiveness
- Conclusion: Toward a globally competitive industry
- Appendix: Oil sands' history of capital costs escalation in detail

This report focuses primarily on the cost of new oil sands projects. There are multiple methods of oil sands production, including in-situ steam-assisted gravity drainage (SAGD), cyclic steam stimulation (CSS), primary or cold flow, and mines with and without upgrading. Some of these methods are discussed in the box "Canadian oil sands primer," along with relevant oil sands background and definitions. SAGD and mines with upgraders are the dominant sources of current production, but SAGD and mines without upgraders represent the majority of greenfield developments today. For this report, our analysis focuses on the cost of SAGD and mines without an upgrader, with some discussion of mines with upgraders.

2. Unless otherwise stated, all values are in US dollars.

## 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 166 billion bbl, 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 crude oil with high viscosity. Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with light oil or converted into a synthetic light crude oil. Different grades of crude oil are produced from bitumen.

**Bitumen blends.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. A common bitumen blend is dilbit—short for diluted bitumen—typically about 70% bitumen and 30% lighter hydrocarbons. We expect the vast majority of oil sands supply growth in the future to be bitumen blends.

**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. We do not expect meaningful growth in SCO supply in the future because of challenging economics.*

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

**Mining.** About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed and stockpiled for later use in reclamation. The layer of oil sands ore is excavated using massive shovels that scoop the material, which is then transported by truck to a processing facility. About 45% of today's production is from mining. Mines can come with and without upgrading units.

- **Integrated mines.** The original mining operations all featured an integrated upgrader that transported bitumen into higher quality SCO.
- **Unintegrated mines.** The two most recent mining operations (one recently completed and another under construction) do not include an upgrader and will, instead, market a bitumen blend.

**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 reservoir to warm and lower the viscosity of the bitumen and allow it to flow to the surface. Similar methods are used in oil fields around the world to recover oil. Thermal processes make up 45% of current oil sands production, and two commercial processes are used today:

- **SAGD.** SAGD is the fastest growing method; it is projected to grow from 34% of production in 2015 to 43% of oil sands production by 2025.
- **CSS.** CSS was the first process used to commercially recover oil sands in situ. CSS currently makes up about 11% of production and is projected to account for less than 8% of total production in 2025.
- **Primary production.** The remaining oil sands production is referred to as primary production. Less viscous, it is extracted without steam using conventional oil production methods. Primary production currently makes up nearly 11% and is projected to be less than 8% by 2025.

For more information on upgrading economics, see the IHS Energy Special Report *Extracting Economic Value from the Canadian Oil Sands: Upgrading and refining in Alberta (or not)?*

# The unconventional Canadian oil sands

## Oil economics 101

Oil production makes money on the difference between the market value of the oil produced and the cost to extract and transport it to market. The decision to invest in new oil production is based on both the anticipated oil price and the cost to produce it (both the operating and capital costs, which together represent most of the full cost of production). Additional elements that have an impact on investment decisions—apart from price and cost—include political risks, such as actual or potential changes to fiscal or regulatory regimes, and security concerns.

The most important determinant behind the cost to produce oil is the reservoir—where oil is found and how much is there. This includes whether operations are located onshore or offshore and if they are in extreme climates or remote areas, what extraction method will be employed such as whether conventional or unconventional techniques or processes are needed.

The reservoir location also influences the project risk—that is, the likelihood that the outcome will not turn out as anticipated. This includes the degree of political stability and physical security. The greater the potential instability, the faster a project may be required to be profitable to offset the risk. Together these are the broad features that underpin project economics.

## The unique attributes of the Canadian oil sands

The Canadian oil sands are unique. In most of the world, oil is found in large reservoirs within the pores and cracks of rocks deep underground. Oil is produced from these formations by drilling down into them. The greater the cracks or permeability, the more easily oil can be recovered. Over time, advancements in drilling and other technologies have enabled access to increasingly complex reservoirs.

The oil found in the oil sands is not trapped within large rocks but within a mixture of sands, clays, and water. After millions of years, the lighter hydrocarbons have escaped or decayed, leaving the larger, longer hydrocarbon chains, which results in a heavy, more viscous crude oil.

Production from the oil sands is unconventional. Extraction is done either by digging up the oil sands ore in surface-top mining operations or in situ, which makes use of more conventional drilling techniques coupled with the injection of steam into the ground to warm and mobilize the bitumen to permit recovery.

Oil sands crude oil itself is also unconventional. Known as bitumen, in its raw state it is semisolid at ambient temperature. To permit bitumen to be piped to market, it is either blended with light oil to produce a lighter bitumen blend or converted into a light SCO.

## It takes scale and large capital investments to overcome oil sands production challenges

Large upfront capital investments in processing equipment and facilities are required to overcome oil sands production challenges. For example, the sand in the oil sands is particularly abrasive, requiring highly durable parts and equipment. The climate in northern Alberta also varies widely from summer to winter. Equipment and infrastructure must be capable of withstanding a temperature variance of over 130 degrees Fahrenheit between seasons, from above 90 degrees Fahrenheit (30 degrees Celsius) in the summer to below minus 40 degrees Fahrenheit (minus 40 degrees Celsius) in the winter.

Projects are scaled up, increasing total construction costs but spreading costs over a larger volume of production to capture economies of scale. This is particularly true for mining operations, which have typically been built in phases in excess of 100,000 b/d—a project scale individually equivalent to about 5% of oil sands production in 2014.[3] In-situ projects

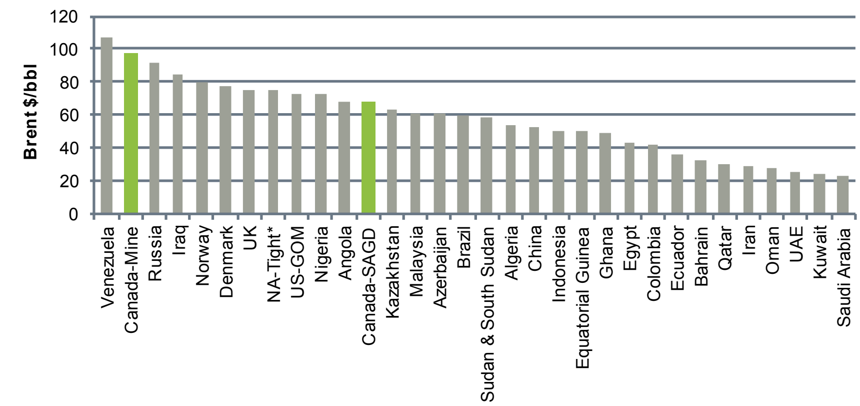
3. The two most recent oil sands mining projects to come online, Phase 1 of Imperial Oil's Kearl project and Phase 1 of Canadian Natural Resources' Horizon project, were initially scaled at 110,000 b/d and 135,000 b/d, respectively.

are typically smaller, historically about 30,000 b/d, but commercial projects have ranged from 5,000 b/d to over 100,000 b/d.[4]

Overcoming oil sands production challenges requires very high levels of investment capital. Most oil sands investments range from $1 billion to $10 billion and take between two to five years to come online once a decision to proceed has been made. But despite the capital required, costs per barrel of production are comparable to many other supply sources in the mid to high range of the cost spectrum (see Figure 1). Once operational, with periodic capital investments, oil sands facilities can produce a steady volume of crude oil for over 30 to 40 years. This long-lasting level of output is different from that of the vast majority of the world's oil fields, which enter into decline after reaching a peak in production. These features compare favorably to other resources that may be lower cost to develop but have greater exploration risk (insufficient oil is found to make production commercially viable) or are located in less politically stable or secure regions, which could cause operational and financial difficulties.

Figure 1

**Average 2014 Brent break-even price full-cycle 10% discount rate by selected nations/supply: Ranked highest to lowest break even with high and low price range for new projects**




Notes: Oil sands growth is dominated by two distinct types of production, mining and SAGD. Mining break even equates to an unintegrated facility without an upgrader that markets diluted bitumen. Break-even price shown in this figure is from 2014 and should be considered as preprice collapse.
Source: IHS Energy



### The Canadian oil sands is not "easy oil"

Over the past 15 years, the Canadian oil sands featured prominently among an array of global opportunities for upstream investors. The attractive characteristics of oil sands production outweighed the negative aspects.

Despite attractive features, the oil sands resource is not "easy oil." Both a remote and challenging climate and geology pose significant development and production challenges. Overcoming these challenges requires large-scale capital investments, as outlined above. As investment in the oil sands grew, other types of challenges emerged—environmental opposition, infrastructure limitations, and cost escalation. This report focuses on oil sands costs and competitiveness. Prior reports in the IHS Oil Sands Dialogue have explored other key challenges.[5]

## Understanding oil sands costs: History and current environment

The cost of an oil sands project includes both the upfront capital cost to design, construct, and start up operations and the cost to operate and maintain production. In this section we look at the history of escalating costs in the oil sands, consider recent upfront capital costs, and then examine the day-to-day cash costs required to operate a facility. At the end of the section, we discuss at which oil prices oil sands facilities break even.

### History and current environment of oil sands upfront capital costs

High—and often rising—upfront capital costs have been a perennial challenge for oil sands investors. There are numerous examples of the final price for a project being significantly higher than the original estimate. From 2000 to the end of 2014, IHS estimates that the upfront capital cost of a SAGD project and mine project increased approximately 70%

4. Pilots or demonstration projects are not included in these estimates.

5. See the recent IHS Energy Special Report *Why the Oil Sands? How a remote, complex resource became a pillar of global supply growth* available at www.ihs.com/oilsandsdialogue.

and 80%, respectively. This means that a project that cost \$2.5 billion in 2000 would cost \$4.25 billion to \$4.5 billion in 2014. This section explores the history and current environment of oil sands capital costs.

### Labor, the largest share of upfront capital costs and largest source of cost increases

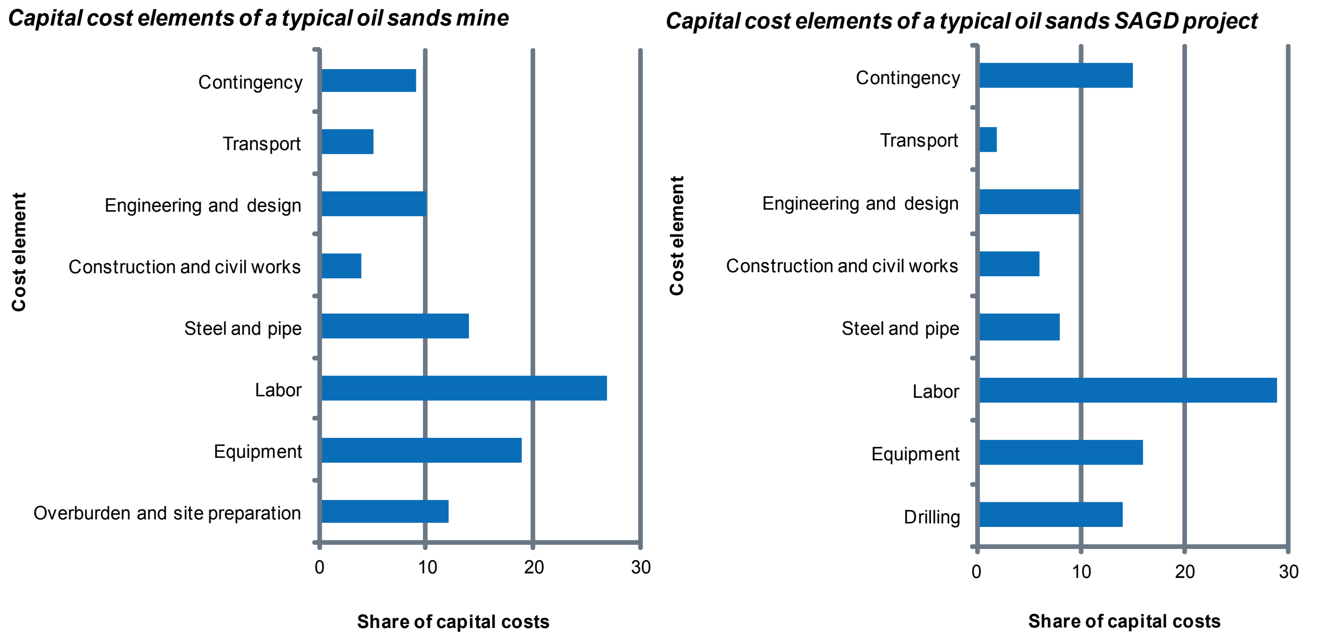
Growth in the Canadian oil sands started to accelerate after 2000, when an increase in global oil prices and the successful deployment of SAGD technology led to a material increase in investment and activity. Mining activity also grew as existing facilities were expanded and several new operations were built. In real terms, capital investment over the past 15 years, from 2000 to 2014, was over five times greater than total capital investment from 1958 to 2000—\$200 billion compared with \$30 billion.[6]

Labor is a key reason for cost differences among regions. Labor costs are a function of both wages and productivity, where productivity is measured by the time required to complete a given task. Alberta's climate is a concern, with cold weather reducing worker productivity. Alberta is also landlocked, keeping on-site labor requirements higher than for regions that have access to tidewater and can import large modularized components from offshore suppliers.

Construction costs for a greenfield project include many elements, but labor is the largest part, accounting for about 30% of total cost (see Figure 2). Other major cost inputs include engineering, design, and project management; cost to purchase equipment, steel, and pipe; and the cost to physically construct the facilities and to transport goods and workers to the site. SAGD has the additional cost to drill and complete steam injection and recovery wells. Mines require more extensive site clearing, involving the removal and storage of vegetation and top soil, as well as the preparation of mine pits. Both types of projects also require contingency funds to cover unforeseen developments.

Figure 2

**Capital cost elements of typical oil sands facilities, 2015**




Notes: The breakdown is the IHS estimate of a typical unintegrated mine without an upgrader and SAGD project. It is based on the IHS oil sands capital costs index, which tracks the cost appreciation of each input over time. This breakdown does not represent any individual project; rather, it is representative of a typical facility.
Source: IHS



6. Canadian Association of Petroleum Producers *Statistical Handbook*.

Since 2000, the cost of globally traded inputs into oil sands projects—such as equipment and steel and pipe—all appreciated, some dramatically. But local factors, such as labor, already relatively more expensive than for many global peers, appreciated as well.

As capital poured into the oil sands and activity increased, the demand for labor and oil field and construction services overtook regional and then provincial capacity and expanded beyond Alberta. This put upward pressure on labor costs. For example, the population of the Municipality of Wood Buffalo (the core oil sands region) more than doubled, from about 52,000 in 2000 to over 116,000 in 2012.[7] Residents of oil sands work camps expanded even more dramatically, from about 6,000 workers in 2000 to over 39,000 by 2012. Moreover, over half of the camp residents did not originate from Alberta, highlighting that labor demands reached beyond the province.

Competition for skilled workers helped push wages up and attracted less experienced workers, lowering productivity. The cost for workers went up, while the length of time it took a worker to complete the same task rose. Rising labor costs also had a knock-on effect on other capital cost elements that relied on the regional labor pool, increasing costs for associated services such as construction, drilling, engineering, site preparation, and overburden removal.

Although labor was the largest factor in escalation of oil sands capital costs over the past 15 years, other factors also helped to drive up costs. We discuss these factors in the appendix, "Oil sands history of capital cost escalation in detail."

## Recent upfront capital cost trends

In 2015, lower oil prices are lowering investment, construction activity, and ultimately costs in the oil sands. However, even prior to the price collapse, there were signs that cost escalation was moderating. Years of investment in building regional infrastructure and in expanding the capacity of the labor market and service sector were helping to moderate cost pressures. Companies have also become more aware of factors that contributed to historical cost escalation, such as labor productivity declines as projects exceed certain scale, and have become more institutionalized in their approach to new projects.

A project's construction costs vary depending on the scale or capacity of the project and the type of extraction (in situ or mining).

To permit comparisons across projects, oil sands capital costs are often expressed as a cost per barrel of production capacity. IHS estimates that at the beginning of 2015, the cost of a typical project ranged from $85,000 to $95,000 for each barrel per day of capacity for a greenfield mine and from $40,000 to $50,000 for each barrel per day of capacity for a greenfield SAGD project (see Table 1).[8] By leveraging existing project infrastructure, such as rights-of-way and cleared land, expansion of existing SAGD facilities can cost as much as $10,000 less for each barrel per day of capacity than a greenfield SAGD facility. Mine expansions generally cannot enjoy the same cost saving. Optimization of an existing mine can increase utilization rates, but meaningful capacity additions will require the construction of a new mine extraction process—known as a mine train. The cost saving of a mining expansion is relatively small compared with the cost of a new mine train.

Table 1

**Typical oil sands project and capital cost at beginning of 2015**

| | Scale | Cost of barrels per day of production capacity (US$) | Total project cost (billion US$) |
|---|---|---|---|
| Mine | 100,000 b/d | $85,000 to $95,000 | 8.5 to 9.5 |
| SAGD (expansion) | 30,000 b/d | $40,000 to $50,000 ($30,000) | 1.2 to 1.5 (1) |

Note: These values are meant to be representative of a typical project and potential range of capital costs for an oil sands unintegrated mine without an upgrader and SAGD project and are not meant represent any specific project.

Source: IHS Energy



Assuming a commercial-scale capacity of 100,000 b/d for a mine and 30,000 b/d for an SAGD facility, the average cost at the beginning of 2015 to construct a greenfield mine and an SAGD project was about $9 billion and $1.4 billion, respectively. SAGD expansion projects (depending on scale) can be about $400 million less than a greenfield SAGD

7. Most recent population estimates place the Municipality of Wood Buffalo population over 125,000. See the Wood Buffalo *Municipal census 2012.*

8. These values are not meant to represent any one specific project. Specific projects may vary from these values. Capital costs are currently falling and may change.

project. These estimates compare with recent greenfield oil sands mining projects that have ranged from $7 billion to $14 billion and in-situ projects of between $500 million and $5 billion (the costs vary by project scale or design capacity).

## Operating costs moved in different directions for different types of projects

The operating costs (also referred to as cash or lifting costs) include the expenses for day-to-day operations of running the facility. If oil prices fall below this line, then the cost to operate the facility is greater than the cash it generates from daily production.[9]

Unlike capital costs, operating costs for oil sands facilities did not rise for all project types (see Figure 3). Costs for mining operations (represented here by integrated mining operations or mines with upgraders) more than doubled, from about $20/bbl in 2005 to over $40/bbl in 2014.[10] In contrast, the operating costs of SAGD facilities managed to stay relatively constant, at between $10 and $20/bbl from 2005 to 2014. SAGD facilities benefited from falling natural gas prices, which account for roughly a third of operating costs; increasing economies of scale from project expansions that occurred over time; and operational improvements that were rolled out, in both existing facilities and newer facilities, incorporating the latest acquired knowledge.[11]

After taking into account transportation and the quality of the different marketed crudes (either SCO or some form of diluted bitumen), IHS estimates that, on average in 2015, an existing SAGD facility requires a WTI basis of between $20 and $35/bbl to cover its cash cost operating costs, and mines with an upgrader need between $30 and $40/bbl.[12]

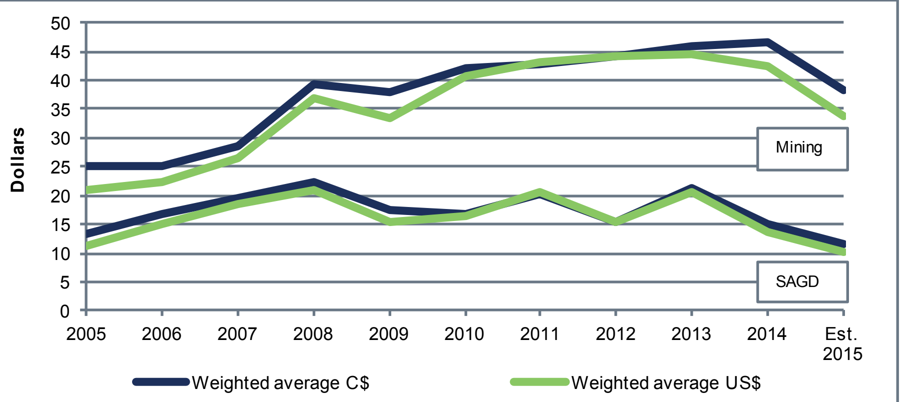
## Oil sands break-even economics

When oil production costs are discussed, it is typically in relation to the full-cycle cost—the total cost to find, develop, and ultimately produce oil. Often this is expressed as the price per barrel of oil required for an investment in new oil production to break even (with a 10% internal rate of return).

Economics of oil sands facilities depend on the design, scale, costs, and market conditions. Break-even points are variable across different projects and as costs decline. IHS used a range to help capture this uncertainty; break-even estimates are based on a high/low range of capital and operating costs and the average market conditions over the first three

Figure 3

Canadian oil sands operating cost (2005 to 2015)




Notes: Operating costs are based on the IHS expertise and interpretation of publicly available information. Owing to data availability and development of new facilities, the sample size and weighting from different facilities changed over time. The weighted average for 2015 is based on operating facilities that accounted for about 75% of SAGD production and all operating mines with an upgrader. Pilot operations and facilities in ramp-up were not included. Operating costs shown here are *not* adjusted for transportation or crude quality. Considerable variability in operating cost exists, and operating cost per barrel can be highly variable as it is a function of both the costs and output.

Source: IHS Energy

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9. There is no fixed definition of what is captured by operating costs versus sustaining capital. Generally, operating costs include essential costs incurred day to day to maintain production. Sustaining capital is defined here as investment that must be made periodically to maintain production levels (not necessarily day to day). In this report, operating costs and sustaining capital do not include any overhead associated with head office administration, taxes, or royalties.

10. Mine operating costs represent facilities with upgraders and include costs associated with upgrading. One more recent facility is in operation without an upgrader, and another is under construction. These more recent facilities are more relevant in relation to production growth but not to historical operating costs.

11. Natural gas prices in western Canada also fell from over $7/MMBtu in 2005 to $4/MMBtu in 2014. Some examples of improvements include the introduction of wedge wells and greater downhole monitoring. These factors helped offset cost pressures.

12. Range shown is indicative of the operating cost over the first three quarters of 2015. The change in operating costs after adjusting for transportation and quality to WTI basis is less pronounced for mines with upgraders because their product, SCO, historically has priced similarly to or at a slight premium to WTI. This compares with dilbit, marketed from most SAGD facilities, which trades at a discount to WTI.

quarters of 2015. IHS analysis should be considered representative of the average break-even cost in 2015 but not any specific project.[13] Costs are falling in 2015, and the break-even point at the end of 2015 is expected to be lower than at the beginning. The impact of cost reductions over 2015 is discussed at the end of this section.

Figure 4 depicts the break-even economics to construct and operate a new oil sands facility. This includes capital cost, which consists of upfront capital investment, operating cost, sustaining capital, and a 10% return on investment. Sustaining capital includes the replacement costs of key equipment, upgrades, and—for in-situ projects—drilling activity to maintain a supply of bitumen.

IHS estimates that on average in 2015 a new oil sands mine required a WTI price between \$85 and \$95/bbl to cover all the costs associated with a project with capacity to produce 100,000 b/d of diluted bitumen. An in-situ SAGD project requires between \$55 and \$65/bbl to produce 30,000 b/d of diluted bitumen. SAGD expansions require prices about \$5/bbl less.

Although not officially a cost associated with a particular project, transportation and crude quality have an impact on project economics. The price western Canadian producers obtain for their crude oil is a function of the quality of the crude—the ease with which it is converted into higher-value refined products—and the cost to deliver or transport it to market. To allow easier comparison, the break-even economics were adjusted for transportation to Cushing, Oklahoma, and for quality to WTI, a light benchmark crude oil (see Figure 4).

It is worth noting that it is clear that although prices in 2015 were below the break-even threshold for new projects (explaining why many have been deferred), an existing facility should have, on average, received sufficient revenue to cover its day-to-day operating costs (as shown by the combined wedge of operating cost and transportation and quality adjustments) (see Figure 4).

## Industry at a turning point—Lower prices and less spending are lowering costs

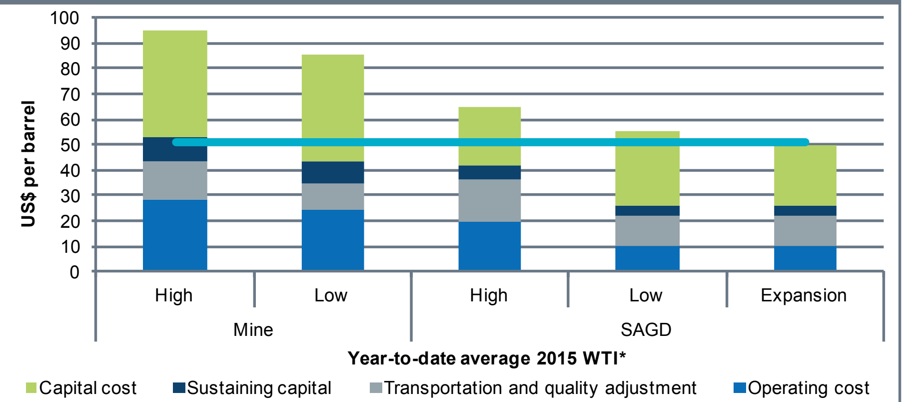
Costs—upfront capital and operating—are dynamic, changing over time and according to market variables. Capital cost increases have been a challenge for oil sands historically, while operating costs have had a more nuanced story. These factors have contributed to the current break-even prices—in the medium to high range of oil investment options.

Even prior to the 2014–15 price collapse, producers were looking to address costs. Efforts are accelerating in the low price environment. Project teams once geared toward developing the next oil sands facility are being redeployed to scrutinize project cost and find opportunities for operating and capital cost reductions.

Capital costs trended down in 2015. As during the 2008–09 downturn, there

Figure 4

**WTI-based break-even price economics of greenfield oil sands projects (estimated average over 2015)**




Notes: Underlying capital costs and operating costs are consistent with a typical greenfield mine without an upgrader, and greenfield SAGD and expansion at the beginning of 2015 (both facilities marketing heavy diluted bitumen blends) using market conditions over the first three quarters of 2015. Underlying capital costs and operating costs are consistent with assumptions presented earlier in this report.
Costs by year-end are expected to be lower; however, the range of assumptions is expected to be consistent with average break-even thresholds over 2015. Additional costs, such as taxes and royalties, are included in the capital cost range but not shown.
Economics of oil sands facilities will depend on the design, scale, project execution, and market conditions. Break-even analysis is based on a typical project and is indicative of the industry at the time of the analysis and is not representative of any one project. Considerable variability between projects exists.
Market volatility—including exchange rates, transportation costs, and diluent prices—in 2015 is influencing the relationship of key oil sands project economic inputs. A number of events also occurred, such as key refinery outages, production outages owing to upsets, and forest fires, which have made 2015 an anomalous year for pricing relationships in western Canada. Uncertainties are captured by showing a range of costs.
*The WTI benchmark price is based on the first nine months of 2015.
Source: IHS Energy



13. Lower prices are leading to cost reduction efforts but are also causing dislocations to a multitude of factors that affect oil sands break-even economics, such as natural gas prices, the exchange rate between Canada and the United States, and the cost of diluent purchased for creation of bitumen blends.

is an opportunity to renegotiate with contractors, gain access to more efficient or productive equipment and labor, and revisit capital investments. There is also less competition for inputs and less pressure on the supply chain. IHS expects the cost to construct a new oil sands production to fall about 6% in 2015 from a year earlier.[14] The Canadian dollar's depreciation against the US dollar, though helpful for producers' revenues, is counteracting some of the benefit of the global slowdown on upfront capital costs by increasing the cost of imports.[15]

Operating costs have also fallen, by about 20% (30% when the exchange rate is factored in), for both mines and SAGD projects in 2015 (see Figure 3). Even lower natural gas prices, greater focus on operational improvement, access to lower service sector rates, and more efficient workers and equipment are all contributing to reductions in 2015. Operators are also maximizing output to spread fixed costs over more units of output. This effectively lowers operating costs reported on a per barrel unit of output.

The net impact of cost reductions is difficult to assess as costs continue to decline and markets are still in transition. But by the end of 2015, overall break-even thresholds could be down by as much as an additional $5/bbl compared with the Figure 4 projections. Certainty some reductions will be temporary—a factor of current market conditions. However, the degree to which cost reductions are longer-lasting will play a role in helping oil sands to maintain its relative competitive position in the world. Yet, reductions are being observed globally, and oil sands' competitive position may still shift. These issues are discussed in the following section.

## Oil sands' competitiveness

The Canadian oil sands figured prominently as a source of global supply growth over the past decade. However, rising cost structures and periodic pipeline constraints (which have reduced the prices that producers have been able to obtain for their crude oil) have lowered anticipated returns for producers, governments, and investors alike. The current lower global oil price environment is intensifying cost reduction efforts but still presents a fresh challenge for the industry.

In the aftermath of the collapse of oil prices in 2014, the oil sands is at a turning point—as is the entire global oil industry. Will lower prices drive material and sustainable cost improvements in the oil sands, or will cost pressures return with higher prices? What types of oil investment will see the greatest production decline—onshore, offshore, or the oil sands? Will the oil sands be able to compete with other sources of supply in the future?

This next section explores the factors that will help shape oil sands' competitiveness and longer-term trajectory of growth.

### Lower prices are slowing oil sands investment

The lower price environment poses a fresh challenge. Average oil prices in 2015, with WTI around $50/bbl, do not support the economics of new greenfield oil sands projects (see Figure 4). As a result, decisions on new projects have been deferred. However, by and large IHS expects both that projects in operation from before the price collapse will continue to operate and that projects under construction will be completed and brought online. At the beginning of 2015, nearly 1 MMb/d of production capacity was at various stages of construction in the oil sands. With the majority of this capacity expected online, IHS expects growth to continue through to 2020, when production is expected to exceed 3 MMb/d, up from an estimated 2.3 MMb/d in 2015. The longer-term growth trajectory depends not only on the timing of the global price recovery but also on the economics of future oil sands projects.[16]

14. Some oil sands producers have different cost reduction expectations; variability is to be expected. But another difference may be what is defined as cost. The IHS Upstream and Oil Sands Capital Costs Indices track only upfront capital construction costs. Oil sands operators will often include companywide cost reductions, such as from lower operating overhead, which can lead to some discrepancies.

15. As of November 2015, the US-Canadian exchange rate had fallen 18 cents since a high last July, when C$1.00 was worth about US$0.94 cents. The lower dollar has benefited Canadian producer revenues because oil is sold in US dollars and many expenses are paid in Canadian dollars. However, the weaker Canadian dollar has also made the cost to import key construction inputs, such as steel, equipment, and replacement parts, more expensive.

16. Since the price collapse began in November 2014, not including pilot or demonstraction projects, one project that had been under construction has been cancelled, one small project that was completed has been placed on hold, and another small-scale project has been shut-in. Some other projects under construction are being rescaled to lower capacity or being divided into multiple smaller projects to lower costs. However, these changes have not materially affected the IHS oil sands production outlook to 2020.

## Prices will eventually return to levels capable of supporting new projects

It will take time for global oil prices to recover. The price collapse of 2014–15 (or longer) has already lasted longer than the 2008–09 collapse. And it will likely be late 2016 or 2017 before the global oil supply glut is worked off. But cutbacks in investment today point to the possibility of weaker supply growth in the future, which could lead to higher prices—assuming that demand growth is steady and significant. The need to replace global production declines will eventually take hold, and adequate prices will be required to incentivize those higher-cost sources of supply in the world that will be needed to balance oil markets over the longer term. This includes not only oil sands but also deepwater offshore and non–North American tight oil, among others.

For the Canadian oil sands, prices will likely need to rise well above break-even levels—and remain there for a period of time—before significant new capital is committed to the construction of new greenfield projects.[17] With the least expensive oil sands projects in 2015 requiring a WTI price of around $50/bbl for SAGD expansions, it may be a year or more before prices could be sufficiently strong to support the economic sanctioning of expansions, let alone greenfield projects. However, if costs fall further, then the break-even price may become lower.

The pace of global demand growth, the dynamics of tight oil production, OPEC production policies, and geopolitics are among the myriad of variables that will help shape an oil price recovery. Throughout this period, the oil industry will struggle to understand a world without OPEC balancing the global oil market. Price volatility is to be expected and will complicate decisions on new projects.

## Oil sands’ global competitive position may shift

The oil price is a key variable in determining the longer-term trajectory of oil sands growth. But so too is access to capital, for which the competition can be fierce. Indeed, lower oil prices are changing the competitive environment for global oil production.

Prior to the global price deflation, the break-even point for new oil sands projects, specifically SAGD, was within a competitive range to other key sources of global supply growth (see Figure 1). Low prices are now lowering costs globally. For example lower prices could push the average global capital cost for new oil projects down by as much as 20% over 2015 and 2016. Within this broad trend, the full-cycle cost—which includes capital costs as well as operating costs and government take—of particular sources of supply will decline at different rates. For example, costs for US tight oil production are expected to fall more than the global average. This differentiation suggests that some producing areas will gain competitive position while others will lose. In this world, if oil sands cost reduction efforts bear less fruit than efforts elsewhere, then oil sands’ competitive position as an investment destination may shift. This could mean that, among companies that invest globally, projects in other regions could be prioritized over those in the oil sands.

## Factors supporting ongoing investment in the Canadian oil sands

Years of large-scale investment have expanded the service and the labor markets in western Canada. The industry approach to oil sands projects and growth is changing. Lower prices are also lowering costs and accelerating structural changes in the industry. How these factors could contribute to a more competitive sector in the future is discussed below.

- **Oil sands projects will, on average, be smaller-scale brownfield in-situ expansion projects.** After more than a decade of strong oil sands investment, sufficient infrastructure is now in place. As a result, production growth will be driven by expansion of existing projects rather than by greenfield developments. Over 70% of production growth during 2015–20 is expected to come from expansions, with over 80% of expansion growth coming from in-situ developments. Expansions are more manageable and predictable than greenfield projects because they are smaller, have shorter lead times, and require less labor.

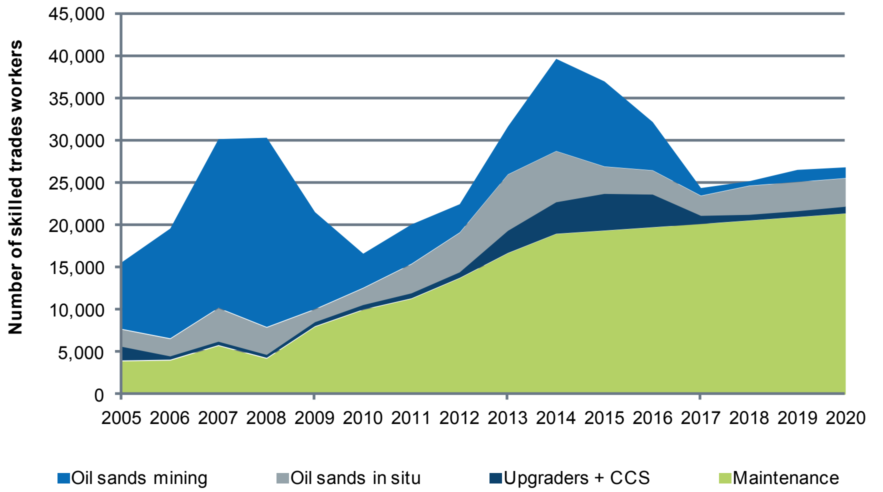
- **Future oil sands labor demand is expected to be lower.** Mines require a large number of workers. In the past, mines have taken four to five years to construct, with peak labor demand near 10,000 workers. More recent mining projects

17. During the previous downturn in 2008–09, some large producers chose to advance projects in the lower price environment to achieve cost savings. Although this is less likely in this downturn, it is still conceivable.

expect a more modest 5,000 workers on site. After the current mine projects under construction are complete, IHS does not expect a new greenfield mining project to advance (barring a transformational change in mining extraction technology). In 2017–18, around the time that labor from mines currently under construction will be finishing their job, IHS projects that oil prices may be entering a range that could justify sanctioning of greenfield oil sands projects. Without a new greenfield mine in the outlook, oil sands labor demand may never return to historical peaks (see Figure 5). This may help keep future labor costs in check.

Figure 5

Estimate of oil sands labor demand (skilled trades workers), 2005–20




Notes: Owing to data limitations before 2010, upgrader and carbon capture and storage workers are captured in mining and in situ, respectively.
Source: IHS Energy

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- **Companies are redesigning projects for lower costs.** Oil companies are revisiting project designs and looking to greater standardization to lower upfront capital cost. Sustaining and operating costs are also being scrutinized for cost savings. Operators are looking to standardize replacement components to lower fabrication costs. Innovations that arise from these efforts may help moderate future cost pressures.

- **Service sector capacity has expanded with oil sands growth.** Years of oil sands growth resulted in an expansion not only of production infrastructure but also of service sector capacity. Fabrication yard capacity, for example, has expanded. Modular fabrication capacity—which allows projects to be constructed in pieces and then later assembled on site—expanded over 400% from 2000 to 2013.[18] As capacity has grown, fabricators have been more willing to enter into longer-term contracts, which in turn provides the industry with greater cost certainty.

- **Project proponents and service providers are adopting a more collaborative approach to project management.** The industry approach to project (and cost) management is also changing. Companies are spending more time advancing engineering and design before beginning construction and making greater efforts once construction is under way to minimize any reworking or reengineering. Project proponents and service providers, such as construction and engineering firms, are making efforts to collaborate more closely on projects. What may make the most sense from a design perspective may not always be the most cost effective to construct.

In many ways, the oil sands were a new industry in 2000. Many changes have occurred over the past 15 years. In addition to an expansion of improvements in infrastructure, service sector, and labor capacity, many lessons have been learned. The oil sands of the future will undoubtedly differ from the past.

## Other headwinds to growth

Although this report focuses almost exclusively on costs, other challenges are contributing to investor caution.[19] This includes market access and potential changes to the oil sands fiscal regime in Alberta.

Opposition to new pipeline development from western Canada has contributed to project delays and rejections. The Keystone XL pipeline, the highest-profile example, was recently denied a permit by the US government. The Northern

18. Extrapolated by IHS from Ekyalimpa, et al., *Model Assembly Capacity: A Study of Alberta Module Constructors,* 2014.

19. Such challenges are discussed in depth in the IHS Energy Special Report *Why the Oil Sands? How a remote, complex resource became a pillar of global supply growth.*

Gateway pipeline now faces the prospect that the Canadian government may deny access to marine tankers. The TransMountain pipeline expansion and Energy East pipeline continue to advance through the regulatory process but, like other pipeline proposals, have faced some degree of delay.

Insufficient pipeline access has forced oil sands producers to accept price discounts—at times steep—for their crude. The rise of crude by rail has established a ceiling for these discounts; but with the price to transport crude by rail exceeding pipeline costs, the greater price stability has not come without a cost.

IHS projects that for the time being western Canada producers should have access to sufficient pipeline capacity. Operational pipeline improvements in 2015, incremental pipeline capacity additions late in 2014, and ongoing production declines brought on by lower prices on conventional production should allow sufficient space in existing pipelines for current oil sands supply. However, at some point in 2016, supply could once again overtake available capacity, increasing price discounts for western Canadian crudes.

In addition, in recent months, the prospects of changes to the fiscal terms and more stringent carbon policies in Alberta moved up the list of challenges facing oil sands development. The June 2015 change in the Alberta government has brought tax, royalty, and carbon pricing to the fore. Since assuming leadership, the new provincial government has increased the corporate income tax from 10% to 12%, announced a plan to expand coverage and raise the price of greenhouse gas emissions, placed a cap on oil sands emissions at 100,000 metric tons, and launched a review of the provincial oil and gas royalty regime.[20] In summary, additional costs associated with taxes, and carbon pricing as well as uncertainty over the future shape of fiscal policies may add to investor caution.

## Conclusion: Toward a globally competitive industry

The oil sands industry has transformed from a niche investment opportunity to one of the most important sources of global oil supply growth. It is an economic engine not just for Alberta but also for Canada. In the earliest days of commercial development, success was about accumulating sufficient land and resource to make a commercial project viable. Then success shifted to constructing greenfield oil sands facilities, the period that is the focus of this report and of capital cost escalation. Now that significant infrastructure has been built over the past 15 years, the industry is shifting to a new period in which success will be measured by efficient operation of existing facilities. Growth will be driven by incremental expansions. The current lower price environment is abetting this transition as new projects are delayed and producers increasingly focus on best practices and operational excellence.

Ultimately, oil sands' competitive position will be shaped by local, regional, and global conditions—including changes to other sources of supply in the world. The challenge facing the oil sands is how much producers can lower their cost structures and the degree to which the pace of future cost escalation can be successfully managed. The oil sands industry—and the governments of Alberta and Canada—can make many changes, but in the global competition for capital, other sources of supply are not standing still.

20. In Canada, provinces typically control the development of natural resources within their borders.

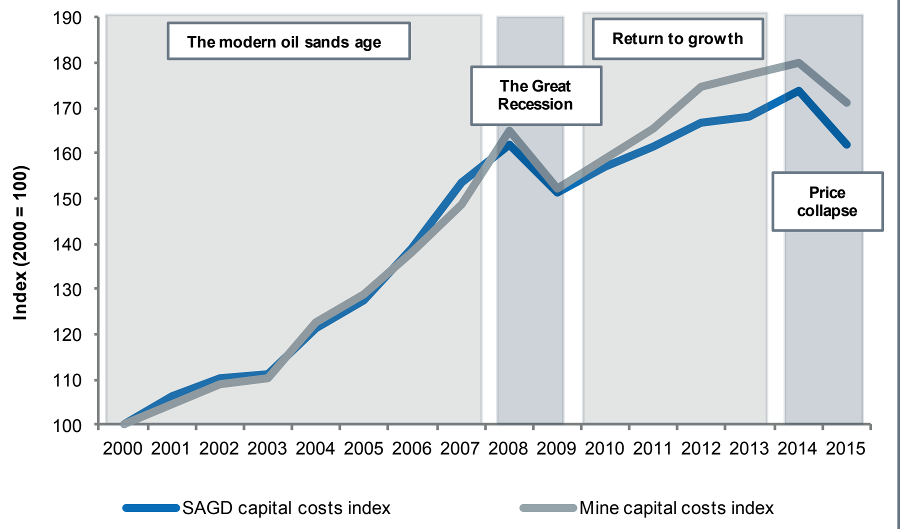
## Appendix: Oil sands' history of capital costs escalation in detail

Over the past 15 years, distinct periods of escalation have occurred (see Figure A-1). These are described below.

**The modern oil sands age (2001–08).** As oil prices appreciated in early 2000s, capital poured into the oil sands, kicking off the modern oil sands age. The first commercial SAGD project came online in 2001 and triggered growth with a new form of extraction. By 2008, SAGD accounted for about 23% of oil sands production.[21] From 2000 to 2008, annual oil sands capital investment in new projects rose from $4 billion to over $18 billion, and IHS estimates that capital costs rose 60%—the greatest period of cost appreciation over the past 15 years. From 2000 to 2008, the number of large oil sands projects in operation more than doubled, from 7 to 18, with construction advancing on several others. This included the expansion of both original mining operations and two completely new mines over this period. All of these mines included upgraders to convert bitumen to SCO, which added to project scale and costs.

Figure A-1

Oil sands capital costs indexes




Source: IHS Energy © 2015 IHS

As labor demand outstripped local and then regional labor supply, wages increased and productivity declined. From 2000 to 2007, the wage for skilled trades in Alberta increased 50% more than the national average—and nearly double what occurred in Ontario, Canada's most populous province.[22]

Labor pressures were amplified by difficulties with project execution. Many workers and companies were at an early stage of the learning and experience curve. Construction at times advanced at a pace that overtook design or that exceeded requirements by either using higher-cost materials or overbuilding in anticipation of future expansions. These missteps ultimately slowed construction, increased labor costs, and contributed to cost overruns.

The oil sands region also lacked adequate infrastructure such as roads and power lines, which had to be built to support growth. This contributed to additional activity, exacerbating demand for labor and material, and helped to push costs higher. This was a period of construction, development, and learning, with many companies advancing their first oil sands in-situ or mining project.

**The Great Recession (2008–09).** The global financial slowdown and the subsequent dramatic, but ultimately short-lived, reduction in global oil prices slowed investment for a time. The price of WTI lost three-quarters of its value, from a high in July 2008 above $140/bbl to under $40/bbl by December. Annual investment in new oil sands projects fell 40%, or $7 billion, between 2008 and 2009. Unsanctioned projects were delayed and some new project construction halted, leading to concern about the economic viability of future growth. Yet, oil sands production growth continued through this period as many projects already under development proceeded to completion, including a mine expansion and three SAGD projects. Projects that continued through the downturn were able to realize cost savings, because the global slowdown helped eased some cost pressures as investment slowed. The labor market loosened, allowing access to more efficient equipment and workers, allowing some companies to realize productivity gains. Overall IHS estimates that capital costs fell by about 6% from 2008 to 2009. However, the cost of some construction inputs, such as steel and pipe, fell by as much as 25%.

21. Production is defined here as raw bitumen, not marketed products.

22. Source: Statistics Canada. Table 282-0069 - Labor force survey estimates (LFS); accessed 15 August 2015.

**The return to growth: 2010–14**. By late 2009, oil prices were recovering, and the oil market entered a period of remarkable price stability. Between 2010 and mid-2014, WTI ranged between $80/bbl and $110/bbl.[23] From 2010 to 2013, annual capital investment in oil sands project development nearly doubled, from $17 billion to $30 billion, as construction accelerated. Along with reinvigorated growth, cost pressures returned as labor demand reached new heights. By 2012, the capital costs for mine and SAGD projects exceeded their pre-recession level. Yet toward the end of this period, there were signs of slowing cost appreciation. For example, prior to the Great Recession, in 2007 capital costs appreciated around 7% per year. In 2010–12, annual capital cost appreciation was lower, at around 4%. Capital cost inflation decelerated further, to around 2% in 2013–14. Years of investment to build regional infrastructure and expand labor market and service sector capacity helped keep a lid on cost escalation. Also, the oil sands industry had matured. Companies had become more aware of factors that contributed to historical cost escalation, such as that labor productivity declines as projects exceed certain scale, and had grown more institutionalized in their approach to new projects. Other global factors, such as an oversupplied steel market, also helped keep capital costs in check.

**The price collapse and the industry at a turning point: 2015+.** The next chapter in oil sands capital costs is being written as the industry copes with the reality of a low price environment, even as costs are declining. This is discussed in the report's final section.

23. Prices ranged from a low of about $70/bbl in 2010 to above $110/bbl in 2011, but on a weekly average basis, prices were between $80/bbl and $110/bbl 88% of the time from 2010 to mid-2014.

## Report participants and reviewers

IHS hosted a focus group meeting in Calgary, Alberta, on 23 October 2014 to provide an opportunity for oil sands stakeholders to discuss perspectives on the key factors that contributed to oil sands growth. Additionally, several key stakeholders participated in a survey that helped form this analysis. A number of participants also 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 is exclusively responsible for the content.

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Canadian Oil Sands Limited

Cenovus Energy Inc.

ConocoPhilips Company

Natural Resources Canada

Shell Canada

Suncor Energy Inc.

TD Securities Inc.

TransCanada Corporation

## IHS team

**Kevin Birn,** Director, IHS Energy, leads the IHS Oil Sands Dialogue. His expertise includes energy and climate policy, project economics, transportation logistics, and market fundamentals. Recent research efforts include analysis of the greenhouse gas intensity of oil sands, economic benefits of oil sands development, upgrading economics, and the future markets for oil sands. Prior to joining IHS, Kevin worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada, helping to inform early Canadian oil sands policy. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US Secretary of Energy. Mr. Birn holds undergraduate and graduate degrees in business and economics from the University of Alberta.

**Jeff Meyer,** Associate Director, IHS Energy, focuses on the global oil market and industry trends. Prior to joining IHS, 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.

# Oil Sands, Greenhouse Gases, and US Oil Supply

## Getting the Numbers Right—2012 Update

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## 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)

We welcome your feedback regarding this IHS CERA report. Please feel free to e-mail us at info@ihscera.com and reference the title of this report in your message. For clients with access to IHSCERA.com, the following features related to this report may be available online: downloadable data (Excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

# 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



IHS CERA

# 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.

*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

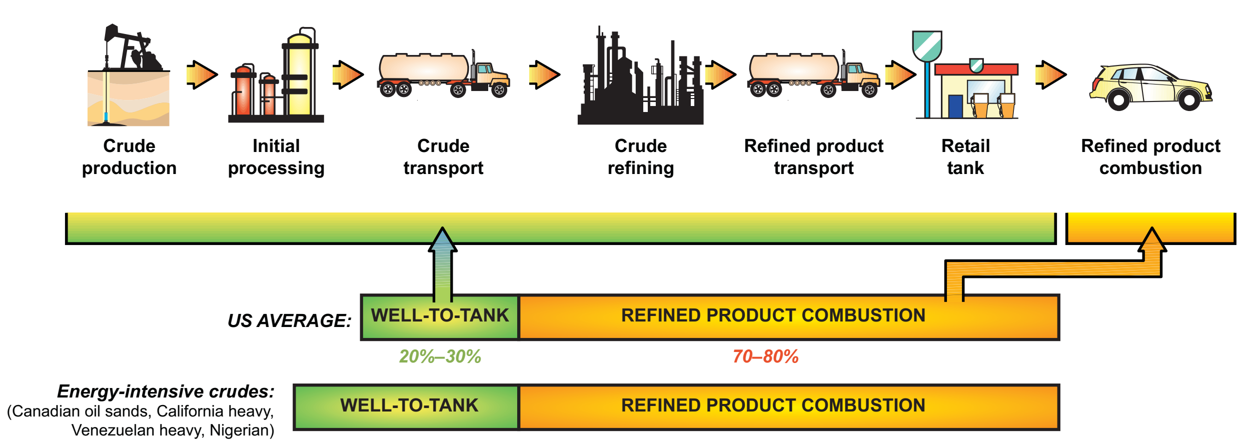
- "the basics" on comparing GHG emissions among crude oils, including a description of life-cycle analysis for crude oil
- an overview of key uncertainties in estimating oil GHG emissions
- and an introduction to meta-analysis—the method used in this report to analyze the GHG emissions for crude oils

### 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**




Source: IHS CERA.
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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.

*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").

*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.

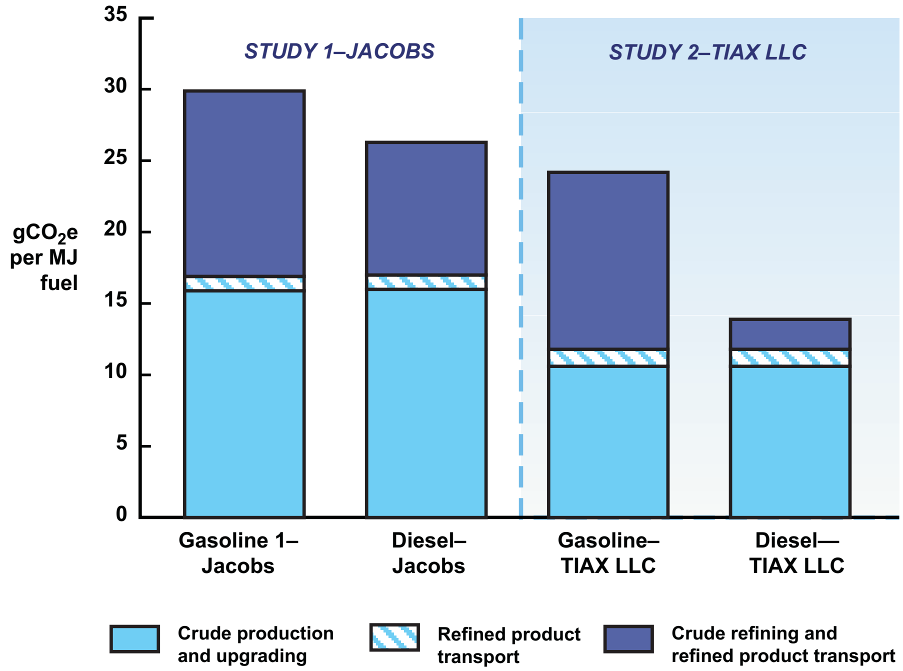
**Comparison of refined product GHG emissions: Jacobs and TIAX LLC**

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**

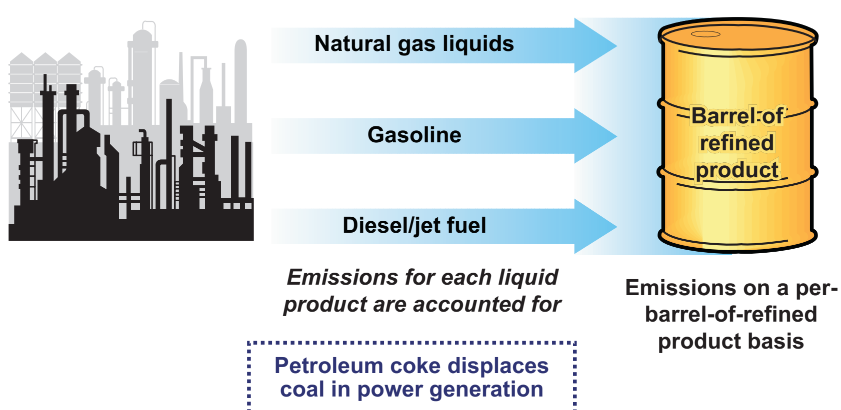
**Well-to-tank emissions from two separate studies with different allocation methods**




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.
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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).

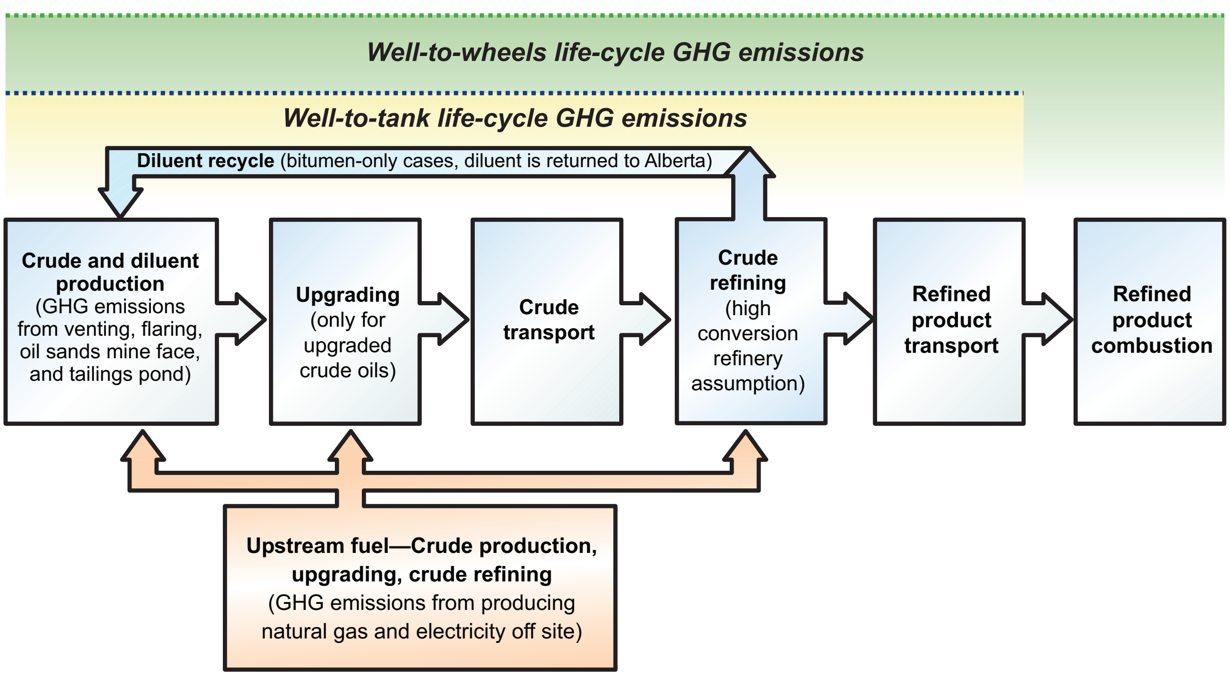
The term *well-to-tank* includes all the emissions from production through refined product transport, while *well-to-wheels* includes all emissions from production through combusting the refined product in a vehicle.

**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.
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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.

*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.

*CARB-OPGEE (2012) land use estimates for crudes from Ecuador and Colombia ranged between 4.7 and 5 kilograms of carbon dioxide equivalent (kg$CO_2$e) per barrel of refined product, while the estimate for oil sands mining was 7 kg$CO_2$e 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

*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.

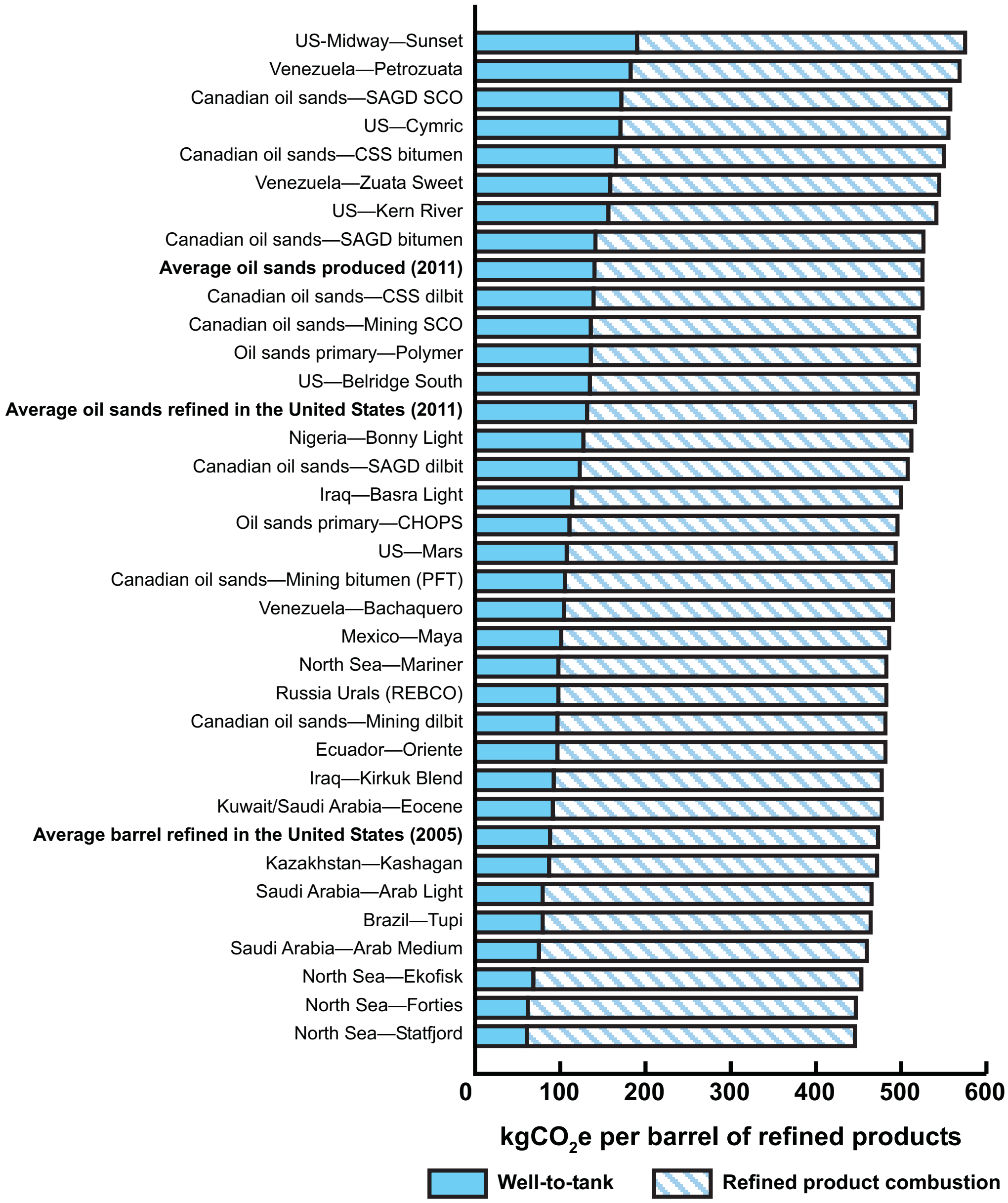
These GHG estimates represent average values across the range of studies included in our meta-analysis. We have not included the high and low ranges for each crude, since the magnitude of the range is purely a function of the number of estimates available, not the uncertainty associated with the reported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




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.

*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 kg$CO_2$e per barrel. Since then, Jacobs (2012) has concluded that the emissions for diluents are materially higher, at 37 kg$CO_2$e 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 (kg$CO_2$e/barrel of refined product)— Tight and wide boundary results

| | Tight Boundary | | | | | | | | Wide Boundary | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Crude name | 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 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 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 elecricity were not included in results.

# Oil Sands, Greenhouse Gases, and European Oil Supply

## Getting the Numbers Right

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**JAMES BURKHARD,** Managing Director of IHS CERA's Global Oil Group, leads the team of IHS CERA experts that analyze and assess upstream and downstream market conditions and changes in the oil and gas industry's competitive environment. A foundation of this work is detailed short- and long-term outlooks for global crude oil and refined products markets that are integrated with outlooks for other energy sources, economic growth, geopolitics, and security. Mr. Burkhard's expertise covers geopolitics, industry dynamics, and global oil demand and supply trends. Mr. Burkhard also leads the IHS CERA Global Energy Scenarios, which combines energy, economic, and security expertise across the IHS Insight businesses into a comprehensive, scenarios-based framework for assessing and projecting global and regional energy market and industry dynamics. Previously he led *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030,* which encompasses the oil, gas, and electricity sectors. He was also the director of the IHS CERA Multiclient Study *Potential versus Reality: West African Oil and Gas to 2020.* He is the coauthor of IHS CERA's respected *World Oil Watch,* which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Before joining IHS CERA Mr. Burkhard was a member of the United States Peace Corps in Niger, West Africa. He directed infrastructure projects to improve water availability and credit facilities. He was also a field operator for Rod Electric. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

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**SAMANTHA GROSS,** IHS CERA Director, specializes in helping energy companies navigate the complex intersection of policy, environment, and technology. She is the manager of IHS CERA's Global Energy service. She led the environmental and social aspects of IHS CERA's recent Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance,* including consideration of water use and quality, local community impacts, and aboriginal issues. Ms. Gross was also the IHS CERA project manager for *Towards a More Energy Efficient World* and *Thirsty Energy: Water and Energy in the 21st Century,* both produced in conjunction with the World Economic Forum. Additional contributions to IHS CERA research include reports on the water impacts of unconventional gas production, international climate change negotiations, US vehicle fuel efficiency regulations, and the California low-carbon fuel standard. Before joining IHS CERA she 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.

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# OIL SANDS, GREENHOUSE GASES, AND EUROPEAN OIL SUPPLY: GETTING THE NUMBERS RIGHT

## EXECUTIVE SUMMARY


As reducing transportation greenhouse gas (GHG) emissions moves to the policy forefront, low carbon fuel standards (LCFS) are charting a new path for regulation. LCFS focus on the fuel, requiring a reduction in GHG emissions across its total life cycle—from production and processing through to using the fuel in a vehicle. In April 2009 the European Union adopted an LCFS by modifying its Fuel Quality Directive. The European Union now requires a 6 percent reduction in life-cycle GHG emissions for fuels used in "road transport and non-road mobile machinery" by 2020. The European Commission is now developing the methodology for calculating and reporting life-cycle emissions, with plans to finalize the policy by the end of 2011.

The European Union has released a draft proposal describing its life-cycle analysis. In IHS CERA's view the methodology is misleading and conveys a confusing picture of oil emissions. The proposal assigns one fixed GHG-intensity value for all fuels produced from crude oil—except for Canadian oil sands. The life-cycle value assigned to oil sands is 23 percent higher than the default value for all other crudes. Oil sands are not exported to the European Union (nor are they expected to be in the future), which also raises the question of why they are separated out from other crudes.

To evaluate the life-cycle GHG intensities of various crude oils, IHS CERA conducted a meta-analysis of 12 publicly available studies and found that, on average, oil sands are not as GHG intensive as the current EU proposal states. On a life-cycle basis, products derived wholly from oil sands result in GHG emissions that are 10 to 20 percent higher than the emissions estimated for the average EU crude. Oil sands products are in the same GHG intensity range as current European imports from Venezuela, Angola, and Nigeria and crudes produced using steam-assisted oil recovery from the Middle East.

Bitumen—the oil in the oil sands—is too thick to transport in its pure form. Therefore, in the hypothetical case that oil sands are imported into Europe, they would be shipped as a blend of bitumen and lighter, less carbon-intensive hydrocarbons or as synthetic crude oil. When this is taken into account, the average oil sands product likely to be imported has life-cycle GHG emissions 11 percent higher than the average EU crude oil—below the 23 percent value in the EU proposal.

The baseline GHG value of the average EU crude oil import is itself an estimate, since data are not available for many crude supplies. For instance, more than 30 percent of EU oil supply comes from countries with elevated levels of gas flaring, a characteristic indicative of higher GHG intensity, yet life-cycle data for these sources of crude are limited.

The method of differentiating oil sands crudes from all other crudes is discriminatory since it does not account for equally high-carbon conventional crude oils already used in the European Union. The proposal provides no clear basis for this distinction. Conventional and unconventional designations are poor guides for life-cycle GHG intensity, particularly for conventional sources with high emissions from venting and flaring. Indeed, the result is to present a distorted view of GHG emissions that can lead to serious errors in policymaking.


—April 2011



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# OIL SANDS, GREENHOUSE GASES, AND EUROPEAN OIL SUPPLY: GETTING THE NUMBERS RIGHT

*by James Burkhard, Jackie Forrest, and Samantha Gross*

## REDUCING TRANSPORTATION GHG EMISSIONS

Reducing greenhouse gas (GHG) emissions is an important policy objective for the members of the European Union. GHG emissions from the consumption of liquid fuels in transport—mainly petroleum-based fuels such as gasoline and diesel—account for about 25 percent of total GHG emissions in the European Union.

Policies to reduce transportation sector fuel use and GHG emissions can take three forms:

- **Focus on the vehicle.** Vehicle carbon emissions standards—similar to fuel economy standards—are an example of a focus on the vehicle. The European Union has mandates to strengthen vehicle carbon emissions standards by 2015.
- **Focus on the fuel.** Substitution of petroleum by lower-carbon biofuels is an example of a fuel policy. The European Union has committed to raising the share of biofuels in transportation to 10 percent by 2020 (although the absolute level of GHG emission reductions from biofuels use can be debated). Another fuel-focused policy measure is low carbon fuel standards (LCFS); the European Union has adopted this policy and is now developing the method of regulating it.
- **Focus on the mode and distance of transport.** Policies that focus on the mode or distance of transport include fuel taxes, congestion charges, pay-as-you drive insurance, greater use of mass transit, and urban planning to reduce travel. Examples are European fuel taxes and congestion charges in central London.

## LOW CARBON FUEL STANDARDS: CHARTING A NEW PATH

LCFS are charting a new path for regulation of GHG emissions in the transportation sector. LCFS focus on the fuel and require a reduction in GHG emissions from the total life cycle of a fuel. As it applies to road transport, the life cycle covers all GHG emissions related to the production, processing, transportation, and final consumption of a fuel in a vehicle. The goal is to have a fuel slate that is less GHG intensive, meaning fewer GHG emissions per unit of energy consumed.

In April 2009 the EU adopted LCFS, modifying its Fuel Quality Directive to require fuel suppliers to reduce the life-cycle GHG emissions for fuels used in “road transport and non-road mobile machinery” by 6 percent by 2020. The methodology for calculating and reporting life-cycle GHG emissions for biofuels was included in the directive. The European Union is now developing the methodology for calculating and reporting GHG emissions from other sources, including petroleum and electricity, and plans to finalize the method, reporting, and default values by the end of 2011.

Although not final, draft values for GHG life-cycle emissions of various fuel sources have been released—including some fuels not currently used in the European Union. The proposal assigns one fixed value for all crude oils with the exception of those produced from oil sands, which are also referred to as tar sands.[1] This one fixed value is inaccurate, because crude oils vary widely in their GHG emissions. The term *oil sands* refers to sand covered with water, bitumen, and clay, specifically that in western Canada (see the box "Canadian Oil Sands Primer"). The Canadian oil sands are one of the most important energy investment destinations in the world. Owing to growth in oil sands supply, Canada currently ranks sixth in global oil production. Over the next decade oil sands production is expected to double, potentially putting Canada within the top five crude oil suppliers globally. Essentially all oil sands are processed and consumed in North America. They are widely considered an important contributor to energy security and to the world's ability to withstand an oil shock. Crudes derived from oil sands are not exported to the European Union nor are they expected to be in the future.[2] This raises the question of why oil sands are separated from other crude oil sources in the draft EU GHG intensity values. The proposal does not explain this—or the reason that GHG emissions from other crude oils are not identified.

Differentiating only oil sands crudes is controversial, since it does not include any means to account for conventional crude oils that have GHG emissions similar to the oil sands. In any case, conventional and unconventional designations are not necessarily good indications of life-cycle GHG intensity, particularly for conventional sources with high emissions from gas venting and flaring.

## MEASURING LIFE-CYCLE GHG CALCULATIONS

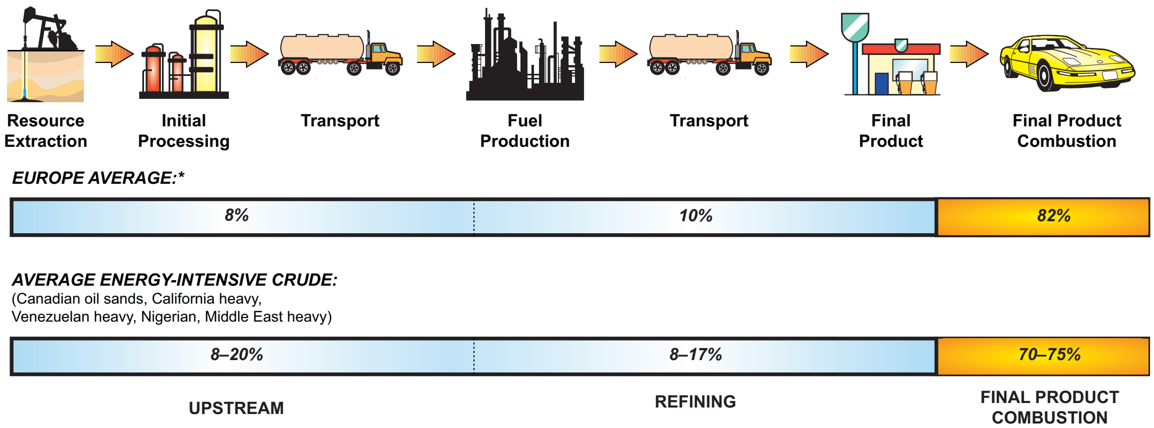
Measuring life-cycle GHG emissions for a transportation fuel is also known as a "well-to-wheels" analysis. Figure 1 illustrates the stages of the life cycle that factor into calculating the GHG emissions for petroleum fuels. A potential benefit of the well-to-wheels approach is that it allows emissions comparison among fuels with very different emission profiles. For instance, the GHG emission profile for a fuel used in a purely electric vehicle—which does not emit carbon dioxide ($CO_2$) from the tailpipe—is different from that for oil, natural gas, or biofuels. Electricity generation from a fossil fuel does emit GHG, but at stages preceding the final consumption of the energy in a vehicle.

Different fuels—oil, biofuels, gas, or electricity—have different life-cycle profiles. But in addition to life-cycle differences among different fuels, there are significant differences within an individual fuel category. Figure 1 compares the average GHG emissions profiles for crude consumed in Europe and for more carbon-intense crudes. Moreover, GHG emissions resulting from production of a single crude oil are not constant over time. More energy is needed to produce oil from more mature fields, although the extent of this increase varies

1. Directive 2009/30/EC amending Directive 98/70/EC on fuel quality consultation paper on the measures necessary for the implementation of Article 7a(5). Page 16 lists proposed default values. In addition to oil sands, the proposal includes unique GHG emission values for other unconventional supplies such as gas-to-liquids and coal-to-liquids.
2. This is based on existing and potential future market outlets for the Canadian oil sands in the United States and Asia; oil sands crudes are not expected to be transported to Europe. Some quantities of diesel fuel derived from oil sands could arrive in Europe through transatlantic trade of refined products. However, as diesel from all crude oil sources is chemically the same, identifying and tracking these volumes would be difficult.

**Figure 1**

**Life-cycle GHG Emissions for Petroleum Fuels**




Source: IHS CERA.
Note: Blue = well-to-retail tank.
*Europe baseline production emissions from "Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries", Stanford University, Adam Brandt (January, 2011), transportation, refining, and fuel combustion emissions using data consistent with IHS CERA meta analysis.
10207-2_1204

among fields. For the oil sands, GHG emissions are far from static. Since 1990 the GHG intensity of mining operations has fallen by 37 percent (on a well-to-retail pump basis); since the inception of SAGD (a decade ago), well-to-retail pump emissions have declined 8 percent per barrel.[1] In measuring GHG intensity for crude oil and the products derived from them, there is no "one size fits all."

Substantially reducing life-cycle GHG emissions from petroleum fuels is challenging. These fuels are inevitably burned, which releases $CO_2$, and the combustion stage accounts for 70 to 80 percent of the total life-cycle emissions. For this reason, the reduction in life-cycle GHG intensity must occur upstream of the vehicle in the oil production, refining, and transportation steps—the portion of the life cycle known as well-to-retail tank. To achieve the EU 6 percent emissions reduction target, petroleum fuels would need to achieve a 20 to 30 percent decrease in well-to-retail tank emissions. Even if emissions from venting and flaring in oil and gas production could be eliminated and the energy efficiency of production improved, this level of reduction from petroleum fuels is not achievable. Consequently, compliance with the LCFS would require lower-carbon alternative transportation fuels—such as biofuels, electricity, hydrogen, or natural gas—to be substituted for higher-carbon petroleum. In the next decade, we expect the numbers of alternative-fuel vehicles (such as electric cars, hydrogen cars, or natural gas vehicles) to be limited, so the EU LCFS compliance will be accomplished mostly with biofuels. In this case, the LCFS and the EU biofuels mandate are duplicative.

1. See the IHS CERA Special Report *Oil Sands Technology: Past, Present, and Future.*

## Canadian Oil Sands Primer

The immensity of the oil sands resource is its signature feature. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 170 billion barrels. Although oil sands are not exported to the European Union, the fact that these reserves would be large enough to meet Europe's demand for more than 30 years gives a sense of their magnitude.*

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands comes from bitumen, 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.) Oil sands are produced by both surface mining and in-situ thermal processes.

- **Mining.** About 20 percent 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 (primarily soils and vegetation) is removed and the oil sands layer is excavated using massive shovels. The sand is then transported by truck, shovel, or pipeline to a processing facility. Slightly more than half of today's production is from mining, and we expect this proportion to be roughly steady through 2030.
- **In-situ thermal processes.** About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling methods. 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 very heavy oil. Two thermal processes are used widely in oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). SAGD accounted for about 18 percent of oil sands production in 2009 and is expected to increase to more than 40 percent by 2030. CSS was used for about 16 percent of oil sands production in 2009 and is expected to decline to less than 10 percent by 2030. Innovations in thermal recovery methods have reduced the amount of energy needed to recover bitumen, and such innovations are likely to continue in the future.
- **Primary.** The remainder of production is primary, or cold flow. Primary made up about 15 percent of oil sands production in 2009 and is expected to decline to less than 5 percent by 2030.

Raw bitumen is solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with light oil liquid or converted into a synthetic light crude oil. The two most common products derived from oil sands are

- **Upgraded bitumen.** Synthetic crude oil (SCO) is produced from bitumen in refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions. Although SCO can be sour, typically SCO is a light, sweet crude oil with no heavy fractions, with API gravity typically greater than 33 degrees. Currently over 90 percent of SCO production comes from mining operations.
- **Bitumen blend, or diluted bitumen (dilbit),** is bitumen mixed with a diluent, typically a natural gas liquid such as condensate. This is done to make the mixed product "lighter," lowering the viscosity enough for the dilbit to be shipped in a pipeline. Some refineries would need modifications to process large amounts of dilbit feedstock because it requires more heavy oil conversion capacity than most crude oils. Dilbit is also lower quality than most crude oils, containing higher levels of sulfur and aromatics. Today the large majority of bitumen blend is derived from in-situ thermal operations.

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*Assumes that average European petroleum demand for the next 30 years is less than 15 million barrels per day.

## Variance and Challenges in Life-cycle GHG Estimates

The idea of using life-cycle emissions to compare the GHG intensity of energy sources is attractive, but there are significant practical challenges to implementing LCFS in a manner consistent with the aim of the policy. Accurate comparisons of GHG intensity require a great deal of high-quality data combined with a comprehensive understanding of fuel production processes.

Given the differences in the data used and the types of inputs considered, evaluating and comparing life-cycle GHG emissions of fuels is complex. Estimates attained from rules of thumb or broad assessments can be helpful for general discussion but are not specific enough to support sound public policy.

Inconsistencies in study results arise from a variety of sources:

- **Data quality, availability, and modeling assumptions.** Often the data used in well-to-wheels analysis are average values or numbers estimated from limited sources. The assumptions about key data and calculations are often not transparent and differ substantially among the various models and studies.

  Data quality and availability for many international crude sources pose an additional challenge. Without accurate and verifiable data, some sources of crude oil, such as Canadian oil sands, could be unduly penalized for being more transparent about their GHG emissions than other sources. If policies that target well-to-wheels emissions use inaccurate assumptions, instead of reducing emissions they could instead shift emissions to countries or sectors with mischaracterized levels of GHG emissions. Today Europe imports crude oil from over 30 countries, and most of these countries provide multiple types of crude oil; ensuring that the data are high quality and available from all locations would be a formidable effort.

- **Allocation of emissions to coproducts.** Well-to-wheels 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 (gasoline, diesel, light petroleum gases, exported power, or even petroleum coke) can vary substantially. Allocation of emissions among numerous refinery products is a key challenge in well-to-wheels analysis, and studies vary greatly in their assumptions. Some conclude that the emissions from refining gasoline are five times higher than the emissions for refining diesel, whereas others find that emissions from refining these two products are almost the same. The difference stems from the assumptions that each study makes about refinery configuration and how to allocate emissions across the various refined products. Including emissions from all products (such as emissions per barrel of all refined products, as used in the IHS CERA analysis) reduces an important source of uncertainty in comparing various study results.

- **System boundary.** Estimates of well-to-wheels emissions require a system boundary—a determination of which emissions are counted and which are not. In estimating the GHG emissions for petroleum, the system boundary is often drawn tightly around the production facilities and the refinery. Emissions directly attributable to production are included, but studies vary on whether they include secondary or indirect emissions. Direct emissions beyond the facility gate are not included in our analysis, nor are indirect emissions. As an example, IHS CERA's life-cycle analyses of oil sands include the GHG emitted when natural gas is combusted to heat water to remove bitumen from the sands, but emissions resulting from the production of natural gas used in the steam boiler are not included (direct off-site emissions), nor are emissions resulting from construction and fabrication of the boilers where the heating occurs (indirect emissions).

## IHS CERA'S META-ANALYSIS

The IHS CERA Special Report meta-analysis *Oil Sands, Greenhouse Gases, and US Oil Supply* (first published in September 2010 and updated here for Europe) puts multiple studies into a consistent framework with the goal of providing a broader comparison than any single study. The Appendix of this Special Report describes IHS CERA's methodology and sources for calculating life-cycle GHG emissions for oil sands and conventional crude oils, as well as the method for estimating the EU "average crude" baseline.

The challenge of accurately estimating life-cycle GHG emissions is reflected in the wide range of results across the 12 studies analyzed. Estimates of well-to-retail tank emissions for specific crudes varied by as much as 45 percent (or 10 percent on a life-cycle or well-to-wheels basis). This variance is more than the 6 percent reduction that the EU LCFS policy requires. The variance among estimates reflects the level of uncertainty in estimating life-cycle GHG emissions and highlights a key challenge in regulating LCFS policies.

In the development of the IHS CERA meta-analysis, we consulted groups representing a wide range of perspectives. The participants—which represented the Canadian and US governments, regulators, oil companies, shipping companies, academia, and nongovernmental organizations—either participated in a focus group meeting or reviewed a draft version of the original report.

To download the original September 2010 study IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply* (including a full list of report reviewers and participants), plus other IHS CERA oil sands research, please visit www2.cera.com\oilsandsdialogue.

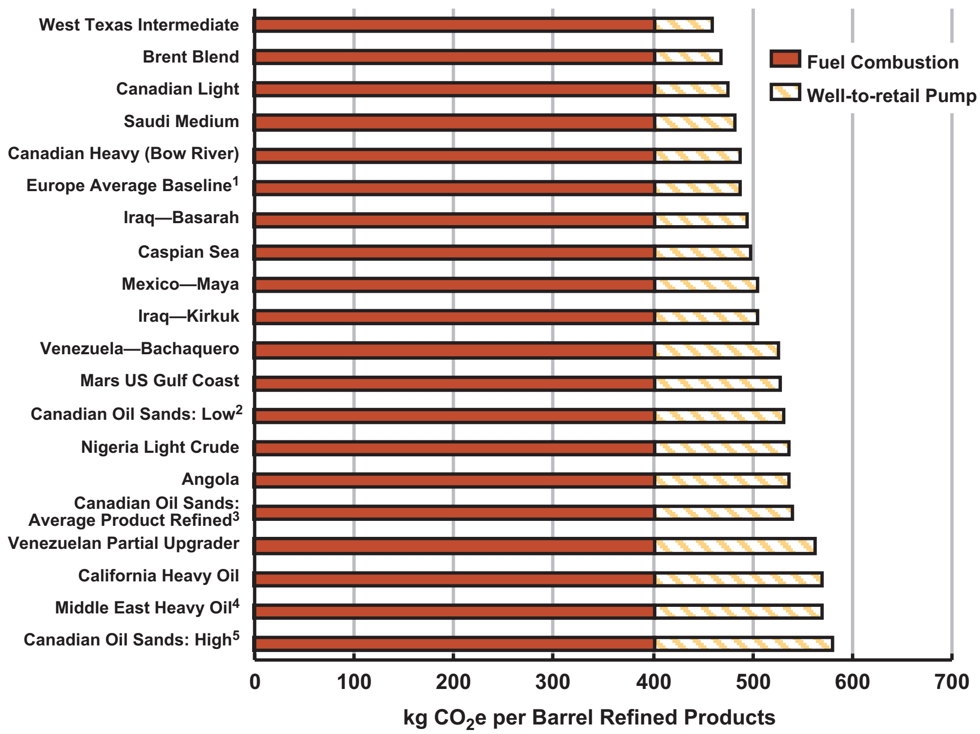
### Comparing Oil Sands Emissions to That of Other Crude Oils

IHS CERA found that on a life-cycle basis, the emissions from refined products wholly derived from oil sands are 10 to 20 percent higher than the estimated average for crudes consumed in Europe. These bookend values represent a 10 percent average for the lowest GHG emissions method (mining) and a 20 percent average for the highest emissions in-situ production method (CSS). They are not meant to encompass the entire range of possible oil sands emissions but merely to provide industry average values suitable for comparison to other sources of crude oil. Oil sands life-cycle GHG emissions are similar to current European imports from Venezuela, Angola, and Nigeria and steam-assisted recovery from the Middle East, which constitute about 6 percent of current supply (see Figure 2 and Table

1).[1] The European Union's current proposal for regulating the LCFS assumes that oil sands have life-cycle emissions 23 percent higher than the default crude—a measurement that is higher than our results. When considering the incremental emissions from oil sands, it is worth considering which oil sands products are likely to be transported to and ultimately refined in Europe. As discussed above, bitumen in its pure form is too thick to transport. Consequently it is shipped as a lower-carbon dilbit blend consisting of bitumen and lighter hydrocarbons. Another option is upgrading the bitumen to SCO. Although SCO can be

**Figure 2**

**Well-to-wheels Greenhouse Gas Emissions for Oil Sands and Other Crudes**




Source: IHS CERA meta analysis of past studies: DOE/NETL 2008, GHGenius, McCann (update 2007), Jacobs-AERI (July 2009), TIAX-AERI (July 2009), RAND (2008), GREET, Syncrude 2007, Shell (2006), CAPP 2008, Suncor 2007, IHS CERA.

1. Europe baseline production emissions from "Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries," Stanford University, Adam Brandt (January, 2011)," transportation, refining, and fuel combustion emissions using data consistent with IHS CERA meta-analysis.
2. Canadian Oil Sands Low is bitumen produced from mining.
3. Average oil sands refined product, considers the mix of supply that can be transported and processed at a refinery—based on 2009 supply data (25% SAGD dilbit, 22.5% CSS dilbit, 48.5% SCO mining, 4% SCO SAGD).
4. Steam injection is used for production.
5. Canadian Oil Sands: High is bitumen produced from CSS.

10410-1

1. For the first eight months of 2010 (the most recent data available). Crude data were sourced from the European Commission Market Observatory for Energy (Registration of Crude Oil Imports and Deliveries in the European Union).

**Table 1**

**Well-to-wheel GHG Emissions for Oil Sands and Conventional Crude Oils Compared to Europe Baseline**

($kgCO_2e$ per barrel refined products)

| | Well-to-retail Pump | Well to Wheels | Difference from "Average European Crude Consumed" (percent) | Component of Europe's Supply? |
|---|---|---|---|---|
| Canadian Oil Sands: High[1] | 179 | 581 | 19 | |
| Middle East Heavy Oil[2] | 169 | 571 | 17 | yes |
| California Heavy Oil | 169 | 571 | 17 | |
| Venezuelan Partial Upgrader | 161 | 563 | 15 | yes |
| Canadian Oil Sands: Average Product Refined[3] | 139 | 541 | 11 | |
| Angola | 135 | 537 | 10 | yes |
| Nigeria Light Crude | 135 | 537 | 10 | yes |
| Canadian Oil Sands: Low[4] | 129 | 531 | 9 | |
| Mars US Gulf Coast | 126 | 528 | 8 | |
| Venezuela—Bachaquero | 125 | 527 | 8 | yes |
| Iraq—Kirkuk | 104 | 506 | 4 | yes |
| Mexico—Maya | 103 | 505 | 3 | yes |
| Caspian Sea | 97 | 499 | 2 | yes |
| Iraq—Basarah | 93 | 495 | 1 | yes |
| Europe Average Baseline[5] | 87 | 489 | 0 | |
| Canadian Heavy (Bow River) | 86 | 488 | (0) | |
| Saudi Medium | 80 | 482 | (1) | yes |
| Canadian Light | 73 | 475 | (3) | |
| Brent Blend | 68 | 470 | (4) | yes |
| West Texas Intermediate | 58 | 460 | (6) | |

Source: IHS CERA, meta analysis of past studies DOE/NETL 2008, GHGenius, McCann (update 2007) , Jacobs-AERI (July 2009), TIAX-AERI (July 2009), RAND (2008), GREET, Syncrude 2007, Shell (2006), CAPP 2008, Suncor 2007.
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4. Canadian Oil Sands Low is bitumen produced from mining.
5. Europe baseline production emissions from "Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries, Stanford University, Adam Brandt (January, 2011)," transportation, refining, and fuel combustion emissions using data consistent with IHS CERA meta-analysis.

produced from mining or in-situ operations, over 90 percent of production comes from lower-carbon mining operations. Therefore the average oil sands product shipped to refineries has GHG emissions 11 percent higher than the estimated emissions for the average crude processed in the European Union.

The EU average crude GHG intensity baseline is uncertain. First, the baseline uses country-level emissions estimates. The margin of error associated with a country-level estimate is 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. The lack of country-level data for many European crude oil suppliers is a second source of error. No specific GHG emissions data were available for countries representing 35 percent of EU crude supply, and default values were assigned for these locations (see the Appendix for more details on the EU baseline calculation). If this country-level approach were applied to western Canadian crude oil, the average upstream emissions would be lower than the average GHG emissions assumed for Angola and Nigeria in the baseline calculation.

Though Europe currently imports crude oils with life-cycle GHG emissions similar to those of oil sands, the EU proposed method groups these other high-carbon crudes in the "conventional" category—providing one life-cycle figure for all crude oils, regardless of their GHG intensity. This appears to be an arbitrary decision that does not represent the reality of world oil supply; it's akin to differentiating crudes from offshore and onshore production, or crudes that are produced east of a given longitude.

Though the majority of European crude supply is light or medium in density, this does not necessarily imply lower carbon. A number of European crude oil supplies (including those from Nigeria, Russia, and Kazakhstan) have higher-than-average life-cycle GHG emissions from flaring (see Figure 3).[1] Though IHS CERA's meta-analysis included a life-cycle GHG emission estimate for Nigeria (which was within the range of oil sands), no prior studies included emissions estimates for Kazakhstan, and Russian data are limited. The two latter countries provide over 30 percent of EU oil supply.[2] Considering the elevated venting emissions in these countries, life-cycle emissions for their crudes could be near or in the range of those from oil sands. Figure 3 shows country-level data for flaring emissions only; it does not include venting or fugitive emissions, which are included in the estimates provided in Figure 2.

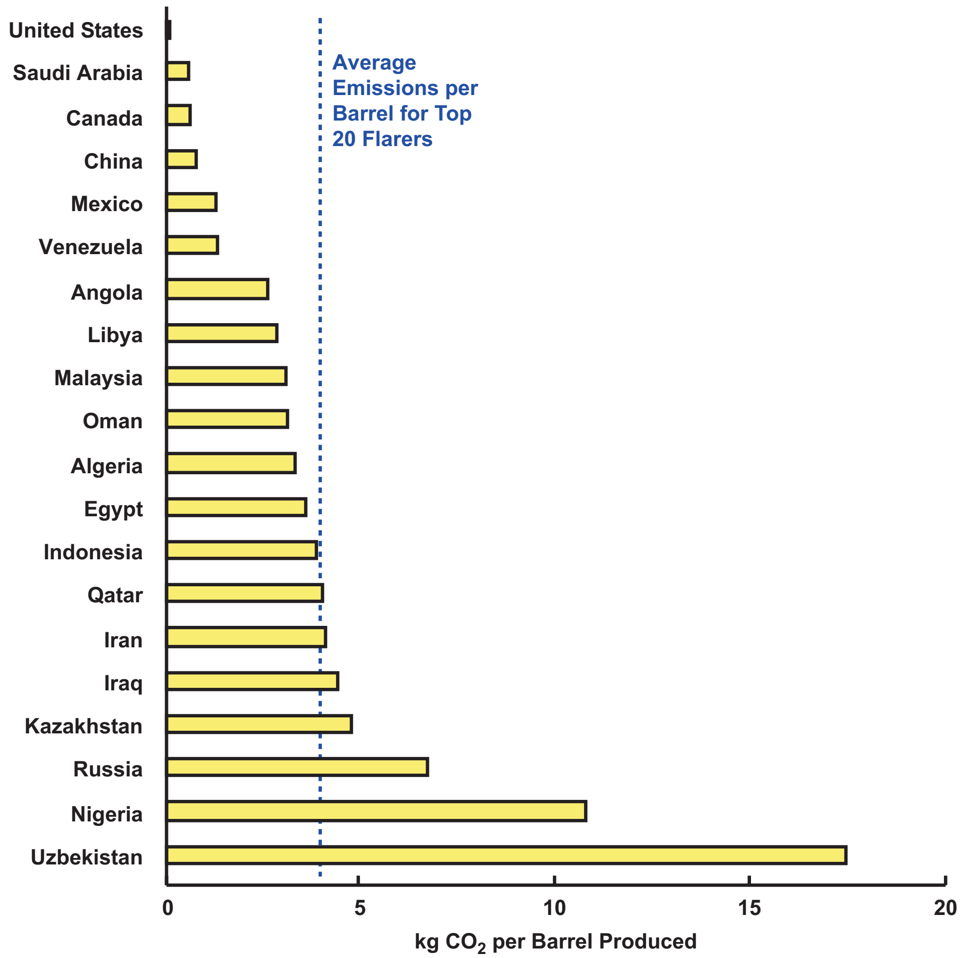
## CONCLUSION

The European Union's LCFS aim to reduce the life-cycle GHG emissions from fuel used in "road transport and non-road mobile machinery." A policy framework that includes recognition of the range of life-cycle GHG emissions of various crude oils would help to achieve the LCFS goals. Conversely, a LCFS policy that does not treat higher-GHG crudes equally, or one that mischaracterizes the GHG emissions from specific fuels, would work against the policy's goal of reducing GHG emissions.

Based on our meta-analysis, on a life-cycle basis the emissions from refined products wholly derived from oil sands are 10 to 20 percent higher than the average for the crudes consumed in Europe. Although not imported to Europe (nor expected to be in the future), oil sands crudes have life-cycle GHG emissions similar to those of other imports—from Venezuela, Angola, and Nigeria and steam-assisted recovery from the Middle East. In the hypothetical

1. Average is defined as the average for the group in the Top Twenty Gas Flaring Countries identified in the World Bank 2009 flaring estimate.
2. For the first eight months of 2010 (the most recent data available). Crude data are sourced from the European Commission Market Observatory for Energy (Registration of Crude Oil Imports and Deliveries in the European Union).

**Figure 3**
**Crude Production Flaring Emissions, 2009**




Source: World Bank Global Gas Flaring Volume Estimates from Satellite Data (2009—Top 20 Countries); 2009 oil production data from IEA.
10410-2

case that oil sands would be imported to Europe, the average oil sands product transported to the refinery would have emissions 9 to 11 percent higher than the European average.

Data quality and availability for many international crude sources pose a challenge to comparing emissions among crude sources. Without accurate and verifiable data, some sources of crude oil, such as Canadian oil sands, could be unduly penalized for being more transparent about their GHG emissions than other sources. If policies that target well-to-wheels emissions use inaccurate assumptions, instead of reducing emissions they could instead shift emissions to countries or sectors with mischaracterized levels of GHG emissions. Transparency is considered a positive characteristic. But it appears that Canadian oil sands are being penalized for being more transparent about their GHG emissions than other sources. Additionally, a one-time estimate of emissions does not take innovation into account: oil sands operators have invested and continue to invest tremendous effort in reducing their GHG emissions.

LCFS are charting a new path in helping governments reach GHG-related policy objectives. Though it takes time to formulate an effective and appropriate policy to allow for data collection and verification and to ensure that all crude sources are accurately characterized, this effort would enhance policy objectives instead of working against them.

# APPENDIX: IHS CERA'S META-ANALYSIS FOR EUROPEAN BASELINE

## IHS CERA METHOD AND SOURCES

In our meta-analysis of 12 separate sources IHS CERA aims to create a common framework to compare the life-cycle emissions of oil sands and other sources of crude oil.[1] We consider the results of each study on an "apples-to-apples" basis by converting them to common units and common system boundaries. We also normalize assumptions across studies to come up with a best estimate of emissions for the various crudes. Some studies calculate only part of the well-to-wheels emissions. To compare the sources on a well-to-wheels basis, emissions for each step in crude oil processing—including crude production, crude transportation, refining, and product distribution—are required. Studies were also put on the same unit basis (some were on a per-barrel-of-gasoline basis and others were on a per-barrel-of-diesel or -of-crude basis).

## UNIT OF MEASURE: GHG EMISSION COMPARISON (KILOGRAMS [KG] OF CARBON DIOXIDE EQUIVALENT [$CO_2$E] PER BARREL OF REFINED PRODUCTS)

We express GHG emissions in units of kilograms of carbon dioxide equivalent (kg $CO_2$e) per barrel of refined product produced. (The definition of refined products is explained in the section Fuel Combustion GHG Emissions.) Some life-cycle analysis studies report GHG emissions on the basis of one barrel of crude oil, gasoline, or diesel. For the studies that reported emissions on a single refined product basis, we used the original studies' assumptions about refined product yields to convert the emissions to a total barrel of refined products basis.

## APPLYING NORMALIZED VALUES: IHS CERA'S BEST ESTIMATE OF WELL-TO-RETAIL TANK GHG EMISSIONS

To ensure uniformity in crude oil comparisons in Figure 2, we normalized the data as described below.

1. IHS CERA has updated the GHG meta-analysis originally published in May 2009 with data from two recent studies commissioned by Energy and Environment Solutions, Alberta Innovates (formerly Alberta Energy Research Institute): *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy, July 2009; and *Comparison of North American and Imported Crude Oil Life-cycle GHG Emissions,* TIAX LCC, July 2009. Other data sources include DOE/NETL: "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008; McCann and Associates: "Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles," November 2001; RAND: "Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs," 2008; NEB: "Canadian Oil Sands: Opportunities and Challenges," 2006; CAPP: "Environmental Challenges and Progress in Canada's Oil Sands," 2008; GREET: Version 1.8b, September 2008; GHGenius: 2007 Crude Oil Production Update, Version 3.8; Syncrude: "2009/10 Sustainability Report"; Shell: "The Shell Sustainability Report, 2006"; and IHS CERA data.

## Crude Production

Estimates of production GHG emissions were derived from the results of the 12 studies. Where multiple studies analyzed the same crude, we used the average value for production-related GHG emissions across the studies. If a particular crude source was analyzed in only one study, we used the value from that study directly.

Table A-1 contains a list of the crude oils we considered, our best estimate of the upstream GHG emissions for each crude, and the range of emissions estimates for each crude from the various studies.

### Calculating the Baseline for Crude Oil Processed in Europe

To establish a baseline, we used the average of production-phase GHG emissions for crudes processed in Europe from a paper by Brandt.[1] Brandt calculated EU volume-weighted average production emissions of 4.83 grams of carbon dioxide ($gCO_2$) per megajoule (converted to our basis, 29.5 kg $CO_2$ per barrel).[2] The EU average value was based on country-level emission estimates; it is an estimate of the average oil production emissions and not a precise number. The margin of error associated with this estimate is 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.

The lack of country-level data for some European crude oil suppliers is a second source of error. We assigned default values to 8 of the 19 countries used in the baseline calculation (or 35 percent of crude supply), since no specific GHG emissions data were available (see Table A-2). If this country-level approach were applied to western Canadian crude oil, the average upstream emissions would be 53 kg $CO_2e$ per barrel of oil produced, lower than the average GHG emissions assumed for Angola and Nigeria in the European baseline calculation.[3]

Russia supplies nearly 30 percent of EU crude; however only one emissions estimate is available and it is at the country level (from DOE/NETL).[4] Considering the high level of gas flaring in Russia (based on World Bank flaring volume estimates), estimate for Russian emissions from DOE/NETL could be low (used in the baseline calculation; see Table A-2).

## Crude Transportation

All 12 original studies were based on a US location for refining and marketing. Therefore, crudes were always assumed to be transported from their origin to the US market. The

1. Adam Brandt, *Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries,* Stanford University, January, 2011. This paper used data from the US Department of Energy (DOE)/ National Energy Technology Laboratory (NETL) report *An evaluation of the extraction, transport and refining of imported crude oils and the impact on life cycle greenhouse gas emissions* (2009).
2. This calculation uses a standard conversion of 6.1 gigajoule per barrel of crude oil.
3. In 2009 western Canadian crude oil production was approximately 9 percent oil sands bitumen produced using cold flow, 27 percent SCO from mining, 3 percent SCO from SAGD, 9 percent bitumen from CSS, 11 percent bitumen from SAGD, 17 percent heavy conventional, and 24 percent light conventional.
4. For the first eight months of 2010 (the most recent data available). Crude data are sourced from the European Commission Market Observatory for Energy (Registration of Crude Oil Imports and Deliveries in the European Union).

**Table A-1**

**Summary of Crude Production GHG Emissions, Average Values, and Sources**

(kg of $CO_2e$ per barrel of refined products)

| | Average Crude Oil Production and Upgrading | Range of Crude Oil Production | Sources |
|---|---|---|---|
| Canadian Oil Sands: CSS Bitumen | 83 | | TIAX-AERI (July 2009) (assumes SOR of 3.35) |
| Canadian Oil Sands: SAGD SCO (Coker) | 116 | 76–133 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009, CAPP 2008 |
| Middle East Heavy Oil[1] | 98 | | IHS CERA (steam injection assumed) |
| Venezuelan Partial Upgrader | 103 | | McCann (update 2007) |
| Canadian Oil Sands: SAGD Bitumen | 69 | 56–80 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009 (equivalent to SOR of 3) |
| California Heavy Oil | 85 | 63–102 | Jacobs-AERI 2009, TIAX-AERI 2009, IHS CERA |
| Canadian Oil Sands: Mining SCO (Coking) | 80 | 34–122 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009, Syncrude 2009/10, Shell 2006, NEB(2008), CAPP 2008 |
| Angola | 82 | | DOE/NETL 2008 |
| Nigeria Light Crude | 82 | 68–93 | McCann 2007, Jacobs AERI 2009, TIAX AERI 2009 |
| Canadian Oil Sands: Mining Bitumen | 33 | 23–42 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009, Syncrude 2009/10, Shell 2006, NEB(2008, CAPP 2008 |
| Canadian Oil Sands: SAGD Dilbit | 50 | | Calculated assuming 70% bitumen and 30% natural gas condensate (8 kgCO2e/bbl assumed for production of condensate) |
| Venezuela—Bachaquero | 41 | 31–53 | Jacobs-AERI 2009, TIAX-AERI 2009 |
| Canadian Oil Sands: Mining Dilbit | 26 | | Calculated assuming 70% bitumen and 30% natural gas condensate (8 kgCO2e/bbl assumed for production of condensate) |
| Iraq—Kirkuk | 51 | | Jacobs-AERI 2009 |
| Mexico—Maya | 32 | 16–43 | DOE/NETL 2008, Jacobs-AERI 2009, TIAX-AERI 2009 |
| Caspian Sea | 47 | | IHS-CERA |
| Saudi Medium | 13 | 1–25 | DOE/NETL 2008, Jacobs-AERI 2009 |
| Canadian Heavy (Bow River) | 15 | | TIAX-AERI 2009 |
| Canadian Light | 20 | | McCann (update 2007) |
| Alaska North Slope | 4 | | TIAX-AERI (July 2009) |
| Brent Blend | 18 | | McCann (update 2007) |

Source: IHS CERA.

Note: All CCS oil sands assume SOR of 3.35. All SAGD oil sands assume SOR of 3.

1. Steam injection is used for production.

**Table A-2**

**Country-level Data for European Baseline Production GHG Emissions**

| Region | Upstream GHG Emissions ($kgCO_2e$ per barrel produced) | Volume Fraction of EU Crude Input |
|---|---|---|
| Unspecified EU production[1] | 25.62 | 0.148 |
| Russian Federation | 33.55 | 0.209 |
| Norway | 6.1 | 0.163 |
| Saudi Arabia | 14.03 | 0.095 |
| Libya[1] | 42.7 | 0.068 |
| Iran[1] | 42.7 | 0.056 |
| United Kingdom | 14.64 | 0.056 |
| Nigeria | 128.71 | 0.032 |
| Algeria | 35.38 | 0.027 |
| Kazakhstan[1] | 42.7 | 0.022 |
| Iraq | 20.13 | 0.022 |
| Denmark[1] | 25.62 | 0.016 |
| Syria[1] | 42.7 | 0.016 |
| Mexico | 39.04 | 0.015 |
| Kuwait | 16.47 | 0.012 |
| Venezuela | 24.4 | 0.011 |
| Azerbaijan[1] | 42.7 | 0.010 |
| Angola | 82.35 | 0.008 |
| Cameroon[1] | 42.7 | 0.009 |
| Egypt[1] | 42.7 | 0.005 |
| Brandt weighted average | 29.5 | |

Source: Brandt study.

1. These countries did not have a country-level GHG estimate, and a default value was applied.

**Table A-3**

**Summary of Crude Transportation GHG Emissions, Average Values, and Sources**

(kg $CO_2e$ per barrel of refined products)

| | Average Crude Oil Transportation | Range of Crude Oil Transportation | Sources |
|---|---|---|---|
| Crude transported within the Continent (Europe or Caspian regions) | 5.5 | 1 to 14 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007, DOE/NETL 2008 |
| Crude transported from rest of the world | 9.1 | 4 to 14 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007, DOE/NETL 2008 |

Source: IHS CERA.

studies included a wide range of estimates for crude transport emissions. IHS CERA normalized the transportation emissions across sources of crude oil by grouping sources into two groups—overseas and North American crudes—and calculating an average value for each group (see Table A-3).

Applying these average values to Europe, the crudes transported from within Europe and the Caspian regions were assigned the "local" value, and crudes from other geographic areas were assigned the overseas value. This is a simplification, since the transport emissions from within Europe and overseas likely vary somewhat from those in North America. However, as transportation emissions make up less than 1 percent of total well-to-wheels emissions, this simplification does not cause a notable change in the relative results.

This method resulted in an estimate of average crude oil transportation emissions for crudes processed in Europe of 8 kg$CO_2$e per barrel of refined products.

## Refining

IHS CERA categorized data on the GHG emissions resulting from refining into six categories of crude oil: light conventional, medium conventional, heavy conventional, extra heavy conventional, SCO, and bitumen. We calculated the average refining emission values for each crude group using estimates from the studies, then used these average values for the IHS CERA meta-analysis (see Table A-4). These average values are an oversimplification of the complexity associated with refining. In reality refining emissions depend on the type of refinery in which the crude is processed, the volume and quality of various refined products produced, and the crude feedstock.

Although the average values are simplified, they do not introduce a significant amount of error on a well-to-wheel basis. The difference in the total well-to-wheels emissions between processing heavy crude in a complex refinery versus refining light crude in a simple refinery is less than 2 to 3 percent. Additionally, without normalizing the values to be consistent across the crudes compared, the results of our comparison could be skewed because the various study authors made different assumptions about refinery complexity.

Taking into account the mix of crudes processed in Europe, we estimate European baseline refining emissions of 47 kg$CO_2$e per barrel of refined products.[1]

For the European analysis, differences between European and North American refineries introduce an additional source of uncertainty. In Europe the refined product mix, refinery complexity, and refinery configurations are different from those in North America. Therefore the average European refining emissions are expected to be slightly different from the US values. However, refining emissions generally make up about 10 percent of well-to-wheels emissions and adjusting to a European basis only affects a fraction of this value; plus all of the crudes would require the same relative adjustment to a new (likely lower) European refining basis. Therefore the error is not expected to make a material change in the relative results.

1. For the first eight months of 2010 (the most recent data available), EU crude densities were 2 percent extra heavy, 8 percent heavy, 23 percent medium, and 69 percent light. Crude data are sourced from the European Commission Market Observatory for Energy (Registration of Crude Oil Imports and Deliveries in the European Union).

**Table A-4**

**Summary of Crude Refining GHG Emissions, Average Values, and Sources**

| | Average "Crude Refining ($kgCO_2e$ per barrel of refined products) | Range of Crude Refining ($kgCO_2e$ per barrel of refined products) | Sources |
|---|---|---|---|
| Light conventional crude (greater than 32 API) | 42 | 30–60 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007 |
| Medium conventional crude (greater than 26 API to 32) | 56 | 44–67 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007, DOE/NETL 2008 |
| Heavy conventional crude (greater than 20 API to 26) | 60 | 47–65 | TIAX-AERI 2009, Jacobs-AERI 2009, DOE/NETL 2008 |
| Extra heavy (less than 20 API) | 73 | 67–79 | TIAX-AERI 2009, Jacobs-AERI 2009 |
| SCO | 47 | 32–64 | GREET, GHGenius, RAND 2008, CAPP 2008, TIAX-AERI 2009, Jacobs AERI 2009, NEB 2008 |
| Bitumen | 85 | | Jacobs AERI 2009 |
| Dilbit | 70 | | Calculated assuming 70 percent bitumen and 30 percent natural gas condensate (30 $kgCO_2e$ per barrel assumed for refining of condensate) |

Source: IHS CERA.

## Refined Product Distribution

The range of estimates for the GHG emissions associated with the distribution of refined products from the refinery to the retail tank varied little among the studies. We used a consistent value across all crude oil sources in our best estimate (see Table A-5).

## Fuel Combustion GHG Emissions

For Europe we assumed an average refined product slate of 50 percent diesel/distillate, 25 percent gasoline, 10 percent gas liquids, and 15 percent residual fuel oil.[1]

In addition to liquid products, refineries also yield petroleum coke, a byproduct of creating the refined products. Coke can be used for a variety of applications, but the most typical use is in power generation. Because the petroleum coke is a byproduct of the refined products, and it is a substitute for using coal in power generation, the emissions from burning coke are not included in the combustion emissions within this analysis. There are some incremental

1. Source: Historical refined product data for Europe from the International Energy Agency.

emissions from substituting petroleum coke for coal in power generation, but for the purposes of this comparison the difference is not material enough to have an impact on the results.

To estimate the combustion emissions for one barrel of refined products, the emissions for each product were apportioned to the mix of products produced (see Table A-6). Combustion emissions for the EU baseline averaged 402 $kgCO_2$ per barrel of refined products—82 percent of the well-to-wheels total for the average EU crude.

Table A-7 shows the well-to-wheels emissions values presented in Figure 2 of this study. This table includes all sources of crude considered, including those that are not part of the European baseline.

**Table A-5**

**Summary of Refined Product Distribution GHG Emissions, Average Values, and Sources**

| | Average Crude Oil Refining ($kgCO_2e$ per barrel of refined products) | Range of Crude Oil Refining ($kgCO_2e$ per barrel of refined products) | Sources |
|---|---|---|---|
| Distribution from refinery to point of sale | 2.1 | 2–2.6 | TIAX-AERI 2009, Jacobs-AERI 2009, DOE/NETL 2008 |

Source: IHS CERA.

**Table A-6**

**Combustion Emissions for Refined Products**

($kgCO_2e$ per barrel of refined product)

| | |
|---|---|
| Gasoline | 375 |
| Diesel/distillate | 422 |
| Residual fuel oil | 495 |
| Gas liquids | 231 |
| Weighted average emissions (full barrel of products) | 402 |

Source: IHS CERA.

## Table A-7

### Summary of Well-to-wheels GHG Emissions for Oil Sands and Conventional Crudes

($kgCO_2e$ per barrel of refined product)

| | Crude Production | Crude Upgrading | Crude Transport | Crude Refining | Distribution of Refined Products | Fuel Combustion | Well-to-retail Pump | Well to Wheels | Percent Difference from Average Europe Crude Consumed | Component of Europe Supply? |
|---|---|---|---|---|---|---|---|---|---|---|
| Canadian oil sands: CCS bitumen[1] (HIGH) | 83 | 0 | 9.1 | 85 | 2.1 | 402 | 179 | 581 | 19 | |
| Canadian oil sands: SAGD SCO (coker) | 69 | 47 | 9.1 | 47 | 2.1 | 402 | 174 | 576 | 18 | |
| Middle East heavy oil[2] | 98 | 0 | 9.1 | 60 | 2.1 | 402 | 169 | 571 | 17 | yes |
| California heavy oil | 85 | 0 | 9.1 | 73 | 2.1 | 402 | 169 | 571 | 17 | |
| Canadian oil sands: SAGD bitumen | 69 | 0 | 9.1 | 85 | 2.1 | 402 | 165 | 567 | 16 | |
| Venezuelan partial upgrader | 103 | 0 | 9.1 | 47 | 2.1 | 402 | 161 | 563 | 15 | yes |
| Canadian Oil Sands: CSS Dilbit[1] | 60 | 25 | 9.1 | 70 | 2.1 | 402 | 141 | 543 | 11 | |
| Canadian oil sands: average refined product[3] | 45 | 47 | 9.1 | 58 | 2.1 | 402 | 139 | 541 | 11 | |
| Canadian oil sands: mining SCO | 33 | 0 | 9.1 | 47 | 2.1 | 402 | 138 | 540 | 11 | |
| Angola | 82 | 0 | 9.1 | 42 | 2.1 | 402 | 135 | 537 | 10 | yes |
| Nigeria light crude | 82 | 0 | 9.1 | 42 | 2.1 | 402 | 135 | 537 | 10 | yes |
| Canadian oil sands: SAGD dilbit | 50 | 0 | 9.1 | 70 | 2.1 | 402 | 131 | 533 | 9 | |
| Canadian oil sands: mining bitumen (LOW) | 33 | 0 | 9.1 | 85 | 2.1 | 402 | 129 | 531 | 9 | |
| Mars US Gulf Coast | 59 | 0 | 9.1 | 56 | 2.1 | 402 | 126 | 528 | 8 | |
| Venezuela—Bachaquero | 41 | 0 | 9.1 | 73 | 2.1 | 402 | 125 | 527 | 8 | yes |
| Canadian oil sands: mining dilbit | 26 | 0 | 9.1 | 70 | 2.1 | 402 | 107 | 509 | 4 | |
| Iraq—Kirkuk | 51 | 0 | 9.1 | 42 | 2.1 | 402 | 104 | 506 | 4 | yes |
| Mexico—Maya | 32 | 0 | 9.1 | 60 | 2.1 | 402 | 103 | 505 | 3 | yes |
| Caspian Sea | 47 | 0 | 5.5 | 42 | 2.1 | 402 | 97 | 499 | 2 | yes |
| Iraq—Basarah | 26 | 0 | 9.1 | 56 | 2.1 | 402 | 93 | 495 | 1 | yes |
| Europe average baseline[4] | 29.5 | 0 | 8 | 47 | 2.1 | 402 | 87 | 489 | | |
| Canadian heavy (Bow River) | 15 | 0 | 9.1 | 60 | 2.1 | 402 | 86 | 488 | 0 | |
| Saudi medium | 13 | 0 | 9.1 | 56 | 2.1 | 402 | 80 | 482 | (1) | yes |
| Canadian light | 20 | 0 | 9.1 | 42 | 2.1 | 402 | 73 | 475 | (3) | |
| Alaska North Scope | 4 | 0 | 9.1 | 56 | 2.1 | 402 | 71 | 473 | (3) | |
| Brent blend | 18 | 0 | 5.5 | 42 | 2.1 | 402 | 68 | 470 | (4) | yes |
| West Texas Intermediate | 5 | 0 | 9.1 | 42 | 2.1 | 402 | 58 | 460 | (6) | |

Source: IHS CERA, meta analysis of past studies DOE/NETL 2008, GHG Genius McCann (update 2007), Jacobs-AERI (July 2009), TIAX-AERI (July 2009), RAND (2008), GREET, Syncrude 2007, Shell (2006), CAPP 2008, Suncor 2007, IHS CERA.

1. Assumes SOR of 3.35 and no electricity export (source for production AERI TIAX).
2. Steam injection is used for production.
3. Average product is based on 2009 supply data (25 percent SAGD dilbit, 22.5 percent CSS dilbit, 48.5 percent SCO mining, 4 percent SCO SAGD).
4. Europe baseline production emissions from "Upstream greenhouse gas (GHG) emissions from Canadian oil sands as a feedstock for European refineries, Standford University, Adam Brandt (January 2011)", transportation, refining, and fuel combustion emissions using data consistent with IHS CERA meta-analysis.

Note: All SAGD crude production cases assume a steam-oil ratio of 3. All oil sands cases marked "Dilbit" assume that the diluent is confirmed in the refinery, with no recycle of diluents back to Alberta, and only 70 percent of the barrel is from oil sands. All oil sands cases marked ""Bitumen"" assume that the diluent is recycled back to Alberta, and all of the barrel processed at the refinery is from oil sands. All SCO cases assume 12 percent loss in upgrading, and therefore 12 percent more bitumen must be produced at the well head or mine.

# Oil Sands, Greenhouse Gases, and US Oil Supply

## Getting the Numbers Right

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## About This Report

**Purpose.** Regulation of GHG emissions is evolving, and policies that consider the full life-cycle emissions of a product are gaining traction. LCFS are charting a new path for regulation in the transportation sector, with direct implications for crude suppliers, particularly for relatively energy-intensive supply sources such as the Canadian oil sands. As regulation of crude oil life-cycle GHG emissions moves to the forefront, accurate, verifiable, and consistent reporting of GHG emissions becomes more important. Uniform reporting requirements would create a "level playing field" for sources of oil supply. The outcome of the debate about life-cycle–based regulation will be an important factor in shaping the economic and political playing field for the oil sands industry.

**Context.** This is the second in 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. The 2010 Dialogue program and associated reports cover four oil sands topics:

- the role of Canadian oil sands in US oil supply
- oil sands, greenhouse gases, and US oil supply: getting the numbers right
- oil sands technology: past, present, and future
- impact of greenhouse gas policies

These reports and IHS CERA's 2009 Multiclient Study *Growth in the Canadian Oil Sands? Finding the New Balance* can be downloaded at www2.cera.com\oilsandsdialogue.

**Methodology.** This report includes multistakeholder input from a focus group meeting held in Calgary on May 14, 2010, 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 end of report for a list of participants and the IHS CERA team).

**Structure.** This report has six major sections:

- Summary of Key Insights of IHS CERA's Analysis
- **Part I: Life-Cycle Analysis Is a New Basis for Policy.** What are LCFS? How can LCFS be regulated?
- **Part II: GHG Emissions from Oil Sands.** How do the GHG emissions from oil sands compare with other sources of crude?
- **Part III: Challenges of Life-cycle Analysis.** Life-cycle analysis is an evolving discipline. What are some of the difficulties of estimating life-cycle emissions of fuels and using these estimates as the basis for policy?
- **Part IV: Implications of Life-cycle Policy on Oil Sands.** What are implications of LCFS on high carbon crudes like oil sands? How can oil sands "fit" into jurisdictions with LCFS?
- Appendix: Details of IHS CERA's GHG Emissions Analysis

# OIL SANDS, GREENHOUSE GASES, AND US OIL SUPPLY: GETTING THE NUMBERS RIGHT

## SUMMARY OF KEY INSIGHTS OF IHS CERA'S ANALYSIS

**Transportation fuels produced solely from oil sands result in well-to-wheels life-cycle greenhouse gas (GHG) emissions 5 to 15 percent higher than the average crude refined in the United States.** Well-to-wheels emissions include those produced during crude oil extraction, processing, distribution, and combustion in an engine. Many analyses of oil sands GHG emissions focus on emissions in the extraction through refining phases, also known as the well-to-retail pump portion of the life cycle. However, 70 to 80 percent of GHG emissions for all sources of crude oil, including oil sands, occur at the combustion phase. Combustion emissions do not vary for a given fuel among sources of crude oil. Oil suppliers influence only the well-to-retail pump emissions, which account for 20 to 30 percent of total life-cycle GHG emissions.

**The average oil sands import to the United States has well-to-wheels life-cycle GHG emissions about 6 percent higher than the average crude refined in the United States.** In 2009 oil sands products imported to the United States were 45 percent synthetic crude oil (SCO) and 55 percent bitumen blends. Bitumen is diluted to make the mixed product "lighter," lowering the viscosity enough for the blend to be shipped in a pipeline. Most often, bitumen blends have lower life-cycle emissions than bitumen because only 70 percent of the barrel is derived from oil sands. Over the past five years the GHG intensity of US oil sands imports has been steady, and over the next two decades the average is projected to remain steady or decrease slightly.

**Life-cycle analysis of GHG emissions is becoming a new basis for policy in the transportation sector.** Many regulations designed to reduce GHG emissions from transportation focus on the fuel economy of vehicles—the distance they can travel on a given volume of fuel. Life-cycle policies instead call for reductions in the well-to-wheels emissions associated with the fuel itself, meaning that improving vehicle fuel economy is not an option to achieve compliance. Low-carbon fuel standards (LCFS) are an example of this type of regulation. LCFS are in place in California, British Columbia, and the European Union, and are under consideration in other jurisdictions. North American jurisdictions implementing or considering LCFS policies represent 34 percent of the US gasoline market and close to 50 percent of the Canadian gasoline market.

**Compliance with LCFS policies will require substantial volumes of alternative fuels.** LCFS in place today call for reductions in life-cycle GHG emissions of up to 10 percent from the current average within a decade. As oil suppliers control only 20 to 30 percent of the well-to-wheels emissions of petroleum fuel, a 10 percent reduction would require suppliers to cut the emissions from crude oil extraction, processing, and distribution by one-third to one-half. Reducing emissions by this large of a margin is not practical for any fuel derived from crude oil. In effect LCFS are alternative fuel standards that require lower-carbon biofuels, natural gas, and electricity to displace oil for transportation use. Oil sands crudes will require about twice the volume of low-carbon fuels to offset emissions as compared with the average crude. Over the next decade limited availability of low-carbon alternative fuels, the vehicles to consume them, and the infrastructure for fuel distribution will make achieving LCFS mandates difficult, no matter what sources of crude oil are used to produce transportation fuels.



IHS CERA

**Life-cycle analysis is an evolving discipline that must deal with a number of uncertainties, making it a challenging basis for policy.** Estimates of well-to-retail pump GHG emissions from a single fuel can vary by more than 10 percent on a well-to-wheels basis. This variance is larger than the GHG emissions reductions that some LCFS require. Additionally, regulating life-cycle emissions requires a trade-off between the complexity of regulation and the level of incentive that it provides for emissions reductions. Establishing broad categories of transportation fuels makes a regulation easier to manage, but more granular regulation of individual fuels provides more incentive for fuel producers to reduce their emissions. Finally, regulations based on the GHG-intensity of fuels do not guarantee an overall reduction in GHG emissions from the transportation sector. Regulations that focus on all three factors influencing transportation GHG emissions—vehicle efficiency, fuel properties, and demand for transportation—are likely to achieve the greatest emissions reductions.

**To implement GHG life-cycle policy for petroleum, the data quality and availability must improve; accurate measurement, verification, and reporting across all sources of oil supply must emerge.** Without such a system, Canadian oil sands could be unduly penalized for being more transparent about their GHG emissions compared with crude oil from other jurisdictions. If policies that target life-cycle emissions are not based on accurate life-cycle GHG data, they could result in unintended consequences, such as shifting emissions to supply sources with mischaracterized levels of GHG emissions.

—September 2010

# OIL SANDS, GREENHOUSE GASES, AND US OIL SUPPLY: GETTING THE NUMBERS RIGHT

The oil sands industry has met the challenge of turning a once uneconomic, unconventional resource into an important pillar of North American and world oil supply. Oil sands are poised to become the largest source of US crude oil imports by the end of 2010. The oil sands story is very much one of overcoming both economic and technical challenges, but additional challenges remain. Evolving policy to reduce GHG emissions from the transportation sector in the United States, Canada, and elsewhere poses a new test for all sources of hydrocarbon supply, but particularly for the oil sands because of their higher carbon intensity.

The objective of this report is to provide an independent perspective on the life-cycle GHG emissions of oil sands compared with other crudes; on the evolving discipline of estimating life-cycle GHG emissions, particularly for oil sands; and on the growing trend of using life-cycle GHG analysis in policy. These policies have the potential to affect the market for Canadian oil sands and other sources of carbon-intensive crude oil.

The first part of this report focuses on understanding how life-cycle GHG analyses are being used to shape transportation fuel policy. The second part clarifies how the GHG emissions from oil sands–derived fuels differ from other sources of fuel (incorporating new data since the analysis published in our May 2009 study, *Growth in the Canadian Oil Sands? Finding the New Balance*). The third part describes several challenges in estimating the life-cycle GHG emissions of fuels, including data quality and availability and consistent system boundaries. The final part describes the potential implications of life-cycle–based regulation on crude oil, including the oil sands. Finally the appendix provides more details about IHS CERA's GHG analysis methodology.

## Oil Sands 101

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, second only to Saudi Arabia. Canada's oil sands are concentrated in three major deposits. The largest is the Athabasca, a large region around Fort McMurray in northeastern Alberta. The other two areas are Peace River in northwest Alberta and Cold Lake, east of Edmonton.

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands comes from 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. Oil sands are unique in that they are produced via both surface mining and in-situ thermal processes.

- **Mining.** About 20 percent 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 (primarily soils and vegetation) 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. Slightly more than half of today's production is from mining, and we expect this proportion to be roughly steady through 2030.
- **In-situ thermal processes.** About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling methods. 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 very heavy oil. Two thermal processes are in wide use in the oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation. SAGD made up about 15 percent of 2009 production and is expected to grow to more than 40 percent of oil sands production by 2030. Innovations in thermal recovery methods have reduced the amount of energy needed to recover bitumen, and such innovations are likely to continue in the future.

Raw bitumen is solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with light oil liquid 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 light crude oil.

- **Upgraded bitumen—SCO** is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions. Although SCO can be sour, typically SCO is a light, sweet crude oil with no heavy fractions, with API gravity typically greater than 33 degrees.
- **Diluted bitumen (dilbit)** is bitumen mixed with a diluent, typically a natural gas liquid such as condensate. This is done to make the mixed product "lighter," lowering the viscosity enough for the dilbit to be shipped in a pipeline. Some refineries will need modifications to process large amounts of dilbit feedstock, because it requires more heavy oil conversion capacity than most crude oils. Dilbit is also lower quality than most crude oils, containing higher levels of sulfur and aromatics.
- **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 than SCO or dilbit alone.
- **Dilsynbit** is a combination of bitumen and heavy conventional crudes blended with condensate and SCO, resulting in a product that more closely resembles conventional crude oil than SCO or dilbit.

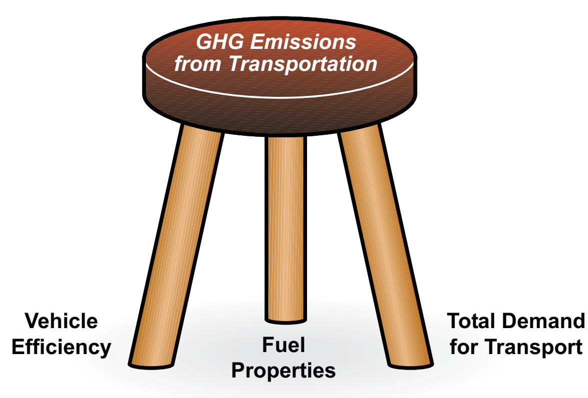
# PART I: LIFE-CYCLE ANALYSIS IS A NEW BASIS FOR POLICY

The world's increasing focus on climate change and reducing GHG emissions has brought new attention to the transportation sector. Transportation makes up 28 percent of US GHG emissions and 14 percent of global GHG emissions. Since petroleum makes up 93 percent of global transportation fuel, the quest to reduce GHG emissions from the transportation sector focuses on replacing petroleum or using it in ways that create fewer GHG emissions. Policy surrounding GHG emissions in transportation is crucial to oil producers, since road transportation accounts for more than 40 percent of world oil demand.

The factors that influence GHG emissions from the transportation sector can be depicted as a three-legged stool, consisting of vehicle fuel economy, fuel properties, and total demand for transport (see Figure 1). Policies that aim to reduce transportation sector GHG emissions can focus on one or more legs of the stool. For example, fuel economy standards focus on the vehicle—on the efficiency of engines, the size of vehicles, and how much fuel it takes to travel a given distance. The federal renewable fuel standard (RFS2) in place today in the United States focuses on the fuel by mandating that specified volumes of biofuels be blended into transportation fuels. Policies that focus on the demand for transport include fuel taxes; congestion charges for drivers that enter inner cities; pay-as-you-drive insurance; urban planning to reduce the need for travel; and subsidizing or encouraging mass transit use, carpooling, or alternatives to transportation such as telecommuting.

**Figure 1**

**Three Factors that Influence Transportation GHG Emissions**




Source: IHS CERA.
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## WHAT IS LIFE-CYCLE ANALYSIS AND HOW DOES IT RELATE TO TRANSPORTATION?

New methods are being developed to better understand and keep track of GHG emissions. One method is life-cycle analysis, which aims to account for all of the GHG emissions associated with a product, from its production through its use. For petroleum transportation fuels, life-cycle analysis encompasses GHG emissions from producing crude oil, refining it into useful products, transporting crude oil and refined products, and combusting the fuel in an engine—often referred to as a "well-to-wheels" analysis.

This method of tracking all GHG emissions associated with a fuel is beginning to enter the realm of transportation policy. Policy based on life-cycle analysis focuses on the fuel leg of the stool, aiming to reduce all emissions attributable to the fuel, not just those released at the tailpipe.

Regulation of life-cycle GHG emissions began in the realm of biofuels. The US Congress passed the Energy Independence and Security Act in 2007, requiring that biofuels achieve specified reductions in life-cycle GHG intensity in comparison with the petroleum fuels they replace (see the box "How Is Policy Based on Life-cycle GHG Emissions Regulated? The RFS2 Example").

LCFS are another form of regulation that relies on life-cycle analysis. LCFS require a reduction in the life-cycle GHG intensity of all types of transportation fuel, not just biofuels. A reduction in life-cycle GHG intensity means reducing the total GHG emissions associated with producing and using transportation fuel, from the oil production well or farmer's field through refining, raw material and finished product transport, and combustion of the fuel in a vehicle's engine. LCFS aim to promote transportation fuels with lower life-cycle GHG emissions without choosing a specific "winning" technology.

LCFS are likely to be most effective in reducing transportation GHG emissions when applied in concert with fuel economy standards and policies that aim to reduce distance traveled, since LCFS alone will not guarantee an absolute decrease in transportation GHG emissions. LCFS require reduced GHG intensity of each unit of fuel by a specified margin; but if the amount of fuel consumed increases, GHG emissions from the transportation sector can still grow. A suite of policies that covers all three factors influencing transportation emissions is required to ensure a reduction in transportation sector emissions.

### LCFS Compared to Cap-and-Trade

LCFS have some important differences from other common ways of regulating GHG emissions. Cap-and-trade policies target GHG reductions across multiple sectors of the economy and are not limited to the transportation sector. They constrain GHG emissions in regulated sectors to a maximum limit or cap and establish a market-based price allowing trading of the right to emit GHG. In contrast LCFS are intensity-based regulations that do not limit total emissions from the transportation sector. The "trade" portion of cap-and-trade policies encourages regulated industries to exploit the least-expensive GHG reductions first. Transportation emissions are typically not the cheapest GHG reductions, meaning that with cap-and-trade policy alone, significant reductions in GHG emissions from the transportation

## How Is Policy Based on Life-cycle GHG Emissions Regulated? The RFS2 Example

RFS2, the US Federal Renewable Fuels Standard, requires the United States transportation sector to consume 2.35 million barrels per day (mbd) of biofuels by 2022. The 2007 revision introduced new categories of renewable fuels and set separate volume requirements and life-cycle GHG emissions reduction thresholds for each. These categories are

- **Renewable fuel.** Requires a 20 percent reduction in life-cycle GHG emissions from the 2005 baseline for gasoline or diesel, whichever it replaces.
- **Biomass-based diesel.** Requires a 50 percent reduction in life-cycle GHG emissions from the 2005 diesel baseline.
- **Advanced biofuel.** Biofuel made from feedstock other than corn starch that achieves a 50 percent reduction in life-cycle GHG emissions from the 2005 gasoline or diesel baseline.
- **Cellulosic biofuel.** Biofuel made from cellulosic materials that achieves a 60 percent reduction in life-cycle GHG emissions from the 2005 gasoline or diesel baseline.

Congress charged the US Environmental Protection Agency (EPA) with implementing RFS2, including determining which fuels comply with the life-cycle GHG performance thresholds and developing a system for administering the standard and ensuring compliance. The RFS2 regulation, developed in collaboration with refiners, renewable fuel producers, and many other stakeholders, went into effect on July 1, 2010.

- **Classifying biofuels for compliance.** Although Congress established in legislation the biofuels categories and their required GHG reductions, it was up to the EPA to determine how to classify various biofuel sources. To make these determinations, EPA modeled the full life cycle of various transportation fuels, including emissions from international land use changes resulting from increased biofuel demand. EPA incorporated numerous modifications to its proposed approach based on comments from the public and a formal peer review. Using this process, the EPA established which combinations of feedstock and production methods fall into which compliance category. For example, EPA modeling results show that sugarcane ethanol produced in Brazil qualifies as advanced biofuel.
- **Tracking biofuels to ensure compliance.** Once a feedstock is processed into a biofuel, it is difficult to determine how the biofuel was made. For example, ethanol produced from corn is chemically the same as ethanol from sugarcane. Therefore, EPA established a system to generate and trade program credits for compliance. These credits are called renewable identification numbers (RINs). RINs are associated with volumes of biofuels produced that meet the four renewable fuel categories, and parties demonstrate compliance by producing the required number of RINs or acquiring them through a trading program.
- **Accounting for changes in life-cycle knowledge.** The assessment of life-cycle GHG emissions is an evolving discipline. As the state of scientific knowledge changes, life-cycle emissions estimates for some sources of fuel may change. If new knowledge changes the compliance status of a fuel source, the new status would be applied only to future production from plants built after the new status was established in regulation. Essentially, once a fuel meets a compliance category, existing production is “grandfathered” into that category. This provision provides regulatory certainty to biofuel producers.

In establishing this regulation, the EPA has demonstrated how it intends to regulate transportation fuel based on life-cycle GHG emissions. Grouping sources of fuel into broad categories based on their production method and emissions reduces the complexity of the regulation. However, these categories remove the incentive for individual renewable fuel suppliers to reduce their life-cycle GHG emissions once they have achieved the required threshold.

sector are not likely. LCFS policies are intended to drive GHG reductions in the transportation sector beyond those that would result from a cap-and-trade policy. In a sense LCFS place a higher value on GHG emissions from the transportation sector than on those from other segments of the economy, since LCFS require emissions reductions from transportation that are likely to be more expensive than other reductions available in the economy—for instance concentrated stationary GHG emissions from industrial facilities. The combination of LCFS with other policies to regulate GHG emissions means that some sources of emissions are likely to be regulated in multiple ways. This situation is not unique, however, and is likely to occur in other sectors also as GHG policies expand.

## Jurisdictions Adopting LCFS on the Rise

As regulation of GHG emissions moves to the forefront, several jurisdictions have established LCFS. In the United States LCFS went into effect in California on January 12, 2010.[1] This standard requires a 10 percent reduction in the GHG intensity of transportation fuel sold in the state by 2020. In Canada, British Columbia has passed a similar standard, also requiring a 10 percent decrease. In the European Union the new fuel directives agreed upon in late 2008 include an LCFS provision that calls for a 6 percent decrease in the carbon intensity of transportation fuels by 2020. Implementing regulations for the directive are in progress.

Other jurisdictions are considering LCFS as well. The governors of 11 states in the US Northeast and Mid-Atlantic signed a letter of intent at the end of 2009 to create LCFS, and LCFS are also under consideration in the states of Oregon and Washington.[2] An LCFS is also under consideration in Ontario. States and provinces implementing or considering LCFS make up 34 percent of the US gasoline market and nearly 50 percent of the Canadian gasoline market.

Today Canadian oil sands are primarily sold and marketed in Canada and the United States, with very limited infrastructure available to export to other markets. Therefore, if these types of policies become more common in both the United States and Canada, the implications for the oil sands industry will become critically important, as will the implications for US energy security.

1. Ongoing lawsuits are challenging California's LCFS on the basis of conflict with the Federal Energy Independence and Security Act of 2007 and interference with interstate commerce.
2. The states that signed the letter of intent are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. Each state would need to implement its own regulation, as there is no regional body with such authority.

# PART II: GHG EMISSIONS FROM OIL SANDS

Concerns about climate change have intensified the worldwide debate about oil resource development, pushing the debate on development of the Canadian oil sands to center stage. But how do the life-cycle GHG emissions of Canadian oil sands compare with other sources of crude oil? Is current data on GHG emissions transparent and complete enough to support the adoption of sound public policy? Canadian oil sands face a greater risk from regulations based on life-cycle emissions because their GHG emissions are greater than many, but not all, sources of oil consumed in the United States.

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

To evaluate the life-cycle GHG emissions of conventional and unconventional crude oils, IHS CERA conducted a meta-analysis of 13 publicly available life-cycle studies.[1]

A meta-analysis combines and analyses the results of multiple studies with the goal of providing more accurate data than any single study (see the Appendix for more information on IHS CERA's meta-study methodology).

Awareness of where and how GHG emissions occur in the petroleum fuel life cycle is crucial to understanding the differences in emissions among crudes. When GHG emissions are viewed on a well-to-wheels basis, the emissions released during the combustion of refined products (such as gasoline and diesel) make up 70 to 80 percent of total emissions (see Figure 2). *The combustion emissions do not vary with the origin of the crude.* For example, tailpipe GHG emissions from an automobile are the same whether the gasoline is made from Saudi light crude, West Texas Intermediate crude, heavy Venezuelan crude, or Canadian oil sands.[2]

Consequently the variability in life-cycle emissions among petroleum fuels occurs in the well-to-retail pump portion of the life cycle—the portion upstream of the vehicle tank.[3] Much of the public debate about oil sands GHG emissions focuses on the well-to-retail pump segment, which constitutes 20 to 30 percent of total emissions. The emissions for

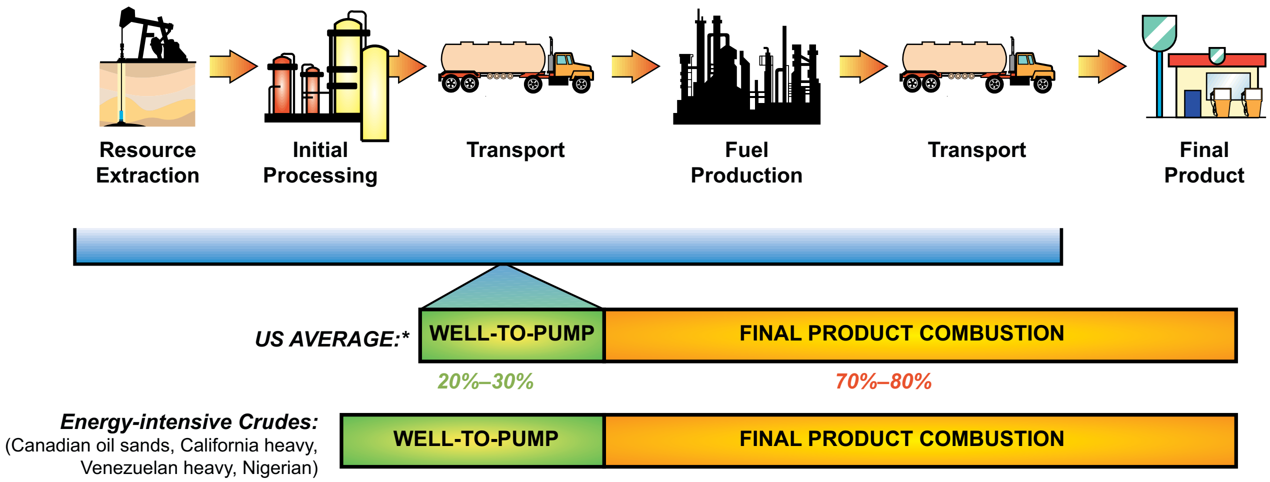
1. IHS CERA has updated the GHG meta-analysis originally published in May 2009 with data from recent studies that Energy and Environment Solutions, Alberta Innovates (formerly Alberta Energy Research Institute) commissioned: *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy, July 2009 and *Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions,* TIAX LCC, July 2009. Other data sources include: *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels,* US Department of Energy/National Energy Technology Laboratory (DOE/NETL), November 2008; "Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles," McCann and Associates, November 2001; *Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs,* RAND Corporation, 2008; *Canadian Oil Sands: Opportunities and Challenges,* National Energy Board (NEB), Canada, 2006; Environmental Challenges and Progress in Canada's Oil Sands, Canadian Association of Petroleum Producers (CAPP), 2008; Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model, Version 1.8b, September 2008; GHGenius, 2007 Crude Oil Production Update, Version 3.8; *2009/10 Sustainability Report,* Syncrude Canada Ltd.; *The Shell Sustainability Report,* 2006, Shell; IHS CERA data.

2. Combustion emissions do very slightly among vehicles running on the same type of fuel.

3. Well-to-retail pump covers GHG emissions from oil production, processing, and distribution of refined products to the retail pump. It excludes combustion of refined products.

**Figure 2**

**Life-cycle GHG Emissions**




Source: IHS CERA.
*Data source: US Department of Energy, November 2008.
90513-30

the well-to-retail pump portion of the value chain differ among crudes because of varying energy requirements for crude oil production, upgrading, transport, and refining.

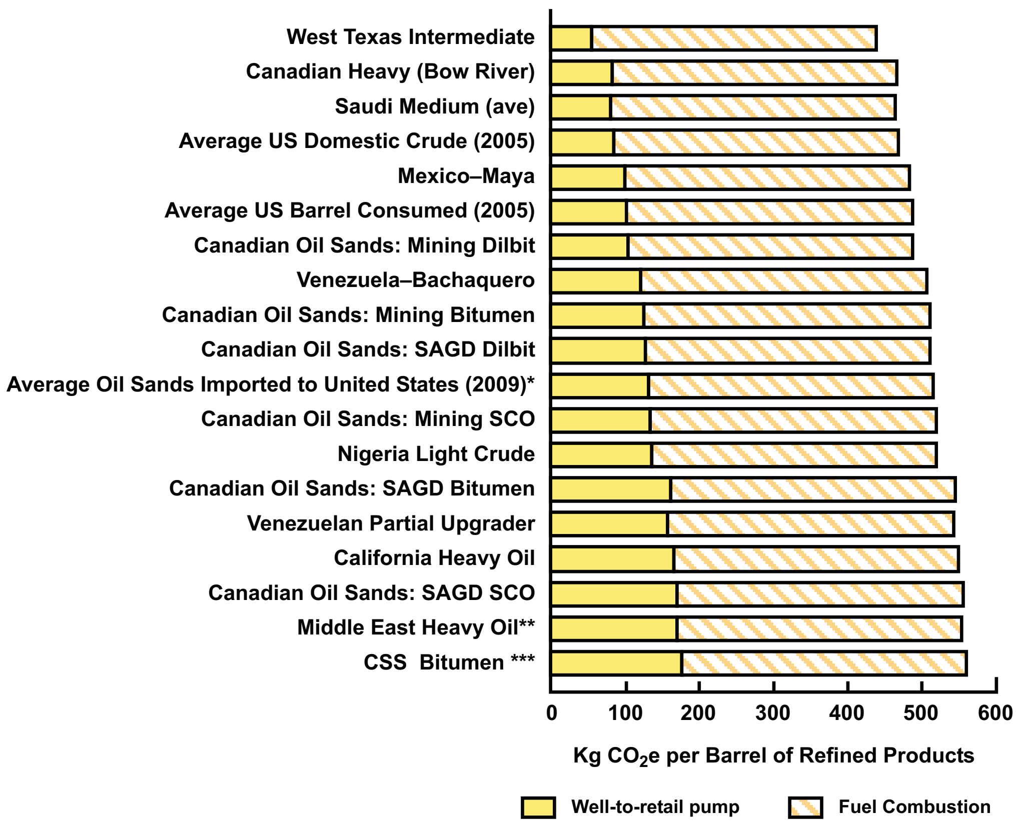
IHS CERA found that when GHG emissions are viewed on a life-cycle basis (well-to-wheels), the emissions from refined products wholly derived from oil sands are 5 to 15 percent higher than the average crude consumed in the United States. These bookend values represent a 5 percent average for mining and a 15 percent average for in-situ production. They do not encompass all possible oil sands emissions, but instead represent average values to use for comparison with other crude oil sources. Although oil sands–derived crudes are more carbon-intensive than the average crude oil consumed in the United States, they are one among several. Other carbon-intensive crude oils are produced, imported, or refined in the United States (see Figure 3).

In 2009 oil sands products processed in the United States were 45 percent SCO and 55 percent bitumen blends. The majority of US SCO imports come from mining operations with well-to-wheels GHG emissions that are 6 percent higher than the average crude. The most common bitumen blend is dilbit, a combination of bitumen and diluents, such as natural gas condensates. Dilbit has lower life-cycle emissions than bitumen because only 70 percent of the dilbit barrel is derived from oil sands. On average, oil sands products processed in the United States result in well-to-wheels GHG emissions about 6 percent higher than the average crude consumed in the United States.[1] Over the past five years the GHG intensity of US oil

1. This is a best estimate and not a precise number. Many types of blends and qualities of SCO are exported, and the available data does not track exports at this level of granularity.

**Figure 3**

**Well-to-wheels Greenhouse Gas Emissions for Oil Sands and Other Crudes**




Source: IHS CERA.
Results of a meta-analysis of 13 publicly available life-cycle studies.
Assumptions:
*Assumes 55 percent of exports to the United States are dilbit blends and 45 percent are SCO (source: NEB 2009 oil sands exports).
**Steam injection is used for production.
***Assumes SOR of 3.35.
12 percent loss of volume upgrading bitumen to SCO.
All SAGD crude production cases assume an SOR of 3.
All oil sands cases marked "Dilbit" assume that the diluent is consumed in the refinery, with no recycle of diluents back to Alberta, and only 70 percent of the barrel is from oil sands.
All oil sands cases marked "Bitumen" assume that the diluent is recycled back to Alberta, and all of the barrel processed at the refinery is from oil sands.
00706-2

sands imports has been steady, and it is expected to remain steady or decrease somewhat over the next 20 years as the energy efficiency of oil sands operations improves.[1]

1. Over the next 20 years the mix of US oil sands imports is projected to shift. Some imports will become more carbon intensive. For instance, as of 2010 Midwest refiners have the option to refine some “bitumen only” oil sands. A condensate recycle pipeline started in 2010 allows refiners to recycle diluent rather than refining it. Meanwhile, other imports will become less carbon intensive—new mining projects without upgraders will increase the imports of lower-carbon oil blends. We project the average carbon intensity of oil sands blends in 2030 to remain about the same as today.

IHS CERA's comparison of publicly available life-cycle analysis studies found that fuel produced from oil sands mining has well-to-retail pump emissions 1.3 times the average fuel consumed in the United States. Similarly fuel produced from oil sands by in-situ methods has well-to-retail pump GHG emissions 1.6 times larger than the average fuel consumed in the United States (see Figure 4).[1] These values correspond to a 5 to 15 percent difference in well-to-wheels emissions, because a majority of emissions occur in the combustion phase, where emissions do not vary among sources of crude oil. In-situ production generally has higher life-cycle GHG emissions than mining because of the steam that must be produced for in-situ extraction. However, in-situ operators have been reducing the amount of steam required to produce each barrel of oil sands over time. The average amount of steam used today per unit of output is about 15 percent lower than the original operations which started less than a decade ago. Technology is expected to continue to improve, enabling greater energy efficiency and thus lower GHG emissions.

## Understanding Differences in GHG Intensity

A wide range of reported values compare the GHG intensity of oil sands with other crudes. Some other studies state that the "gap" between oil sands crudes and others is much higher than the IHS CERA analysis. What are some of the main drivers for the differences between these reports and our analysis?

One difference is that some studies only compare GHG emissions from part of the life cycle. Some studies state GHG emissions from oil sands are three times greater than conventional crudes. Although not always stated, these studies compare only the emissions from producing

### How Do Emissions for Dilbit Stack Up?

Bitumen is too viscous to transport through pipelines at ambient temperatures—it must be diluted to lower its viscosity for transportation. Diluted bitumen is called dilbit. Natural gas liquids, such as condensates, are used to dilute the bitumen. The life-cycle carbon emissions described above are for crude oil derived entirely from oil sands. How do these emissions compare to the life-cycle emissions of dilbit?

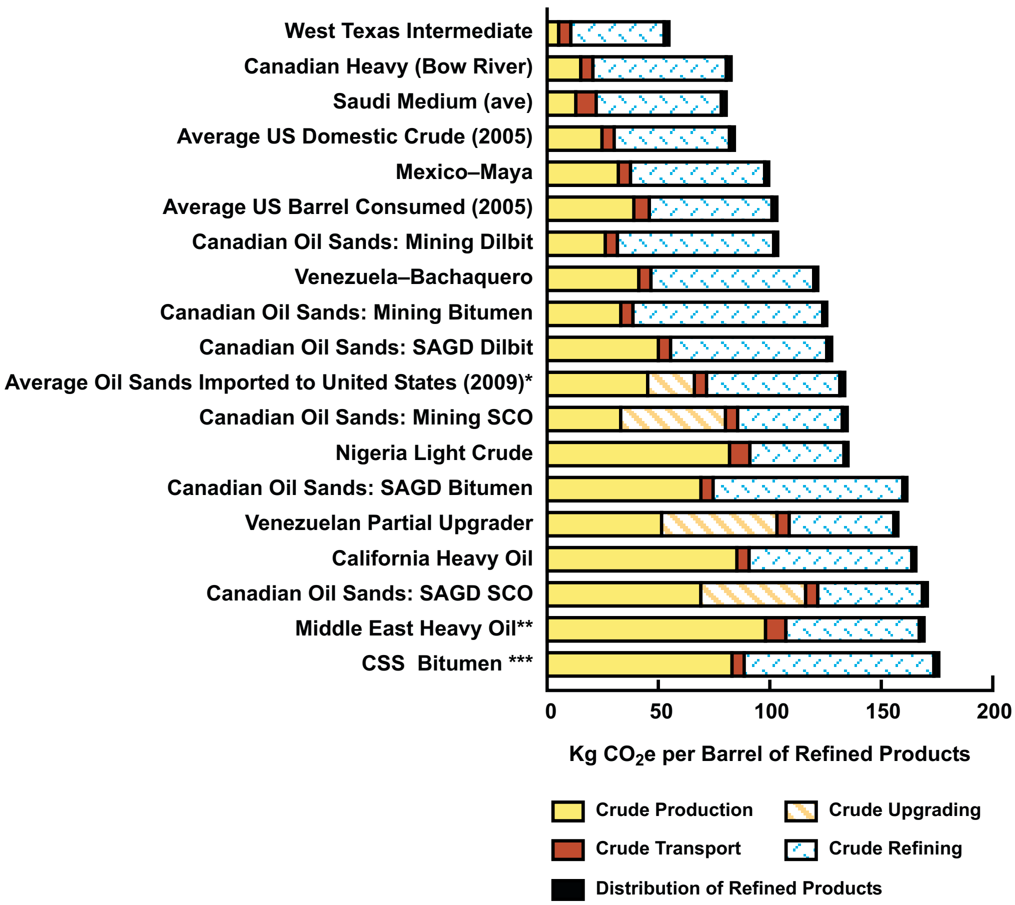
Producing a barrel of condensate emits one fifth of the GHG emissions associated with producing the same volume of bitumen; and refining a barrel of condensate emits one third of the GHG emissions associated with refining bitumen. Therefore, when the raw bitumen is diluted with the less carbon-intensive condensate, the resulting barrel of dilbit has lower life-cycle emissions than a barrel of bitumen.

Figure 5 compares the GHG emissions for a barrel of products produced from dilbit with those for a barrel of products produced from bitumen. The GHG emissions of a barrel of refined products produced from mining dilbit are 0.1 percent greater on a well-to-wheels basis than the average crude consumed in the United States, compared with 5 percent for bitumen. For dilbit produced from SAGD, the well-to-wheel emissions are 5 percent greater than the average crude consumed in the United States, compared with 12 percent for bitumen.

1. These comparisons represent today's mining and in-situ technology compared to the 2005 baseline provided by the US NETL in *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels,* November 2008.

**Figure 4**

**Well-to-retail pump Greenhouse Gas Emissions for Oil Sands and Other Crudes**

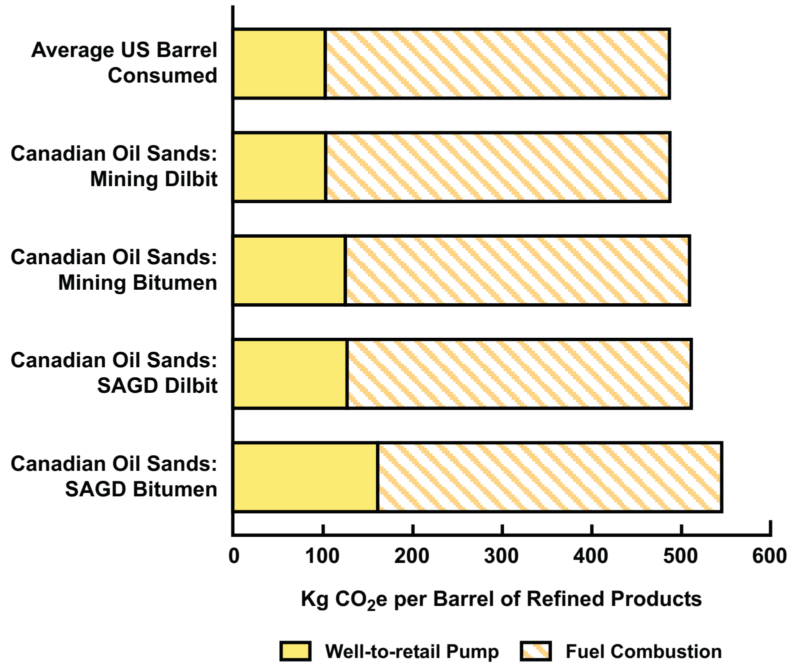



Source: IHS CERA.
Results of a meta-analysis of 13 publicly available life-cycle studies.
Assumptions:
*Assumes 55 percent of exports to the US are dilbit blends and 45 percent are SCO (Source NEB 2009 oil sands exports).
**Steam injection is used for production.
***Assumes SOR of 3.35.
12 percent loss of volume upgrading bitumen to SCO.
All SAGD crude production cases assume an SOR of 3.
All oil sands cases marked "Dilbit" assume that the diluent is consumed in the refinery, with no recycle of diluents back to Alberta, and only 70 percent of the barrel is from oil sands.
All oil sands cases marked "Bitumen" assume that the diluent is recycled back to Alberta, and all of the barrel processed at the refinery is from oil sands.
00706-3

the oil. Other studies state that GHG emissions from oil sands are five times greater than conventional crudes. Often, these studies compare the emissions from producing bitumen and upgrading it to SCO to the emissions from producing conventional oil. SCO is partially

**Figure 5**

**Comparing Well-to-wheels Greenhouse Gas Emissions: Refining Dilbit versus Refining Bitumen**




Source: IHS CERA.
All SAGD crude production cases assume an SOR of 3.
All oil sands cases marked "Bitumen" assume that the diluent is recycled back to Alberta, and all of the barrel processed at the refinery is from oil sands.
All oil sands cases marked "Dilbit" assume that the diluent is consumed in the refinery, with no recycle of diluents back to Alberta, and only 70 percent of the barrel is from oil sands.
00706-4

refined, so a more balanced comparison would include the production though refining emissions for each source of crude oil included in the analysis.[1]

Another important difference among studies is the baseline to which oil sands crudes are compared. Some studies compare oil sands to light, sweet crude, while others compare the resource to the average crude produced in the United States. Our analysis compares the average emissions from oil sands to those from the average crude consumed in the United States in 2005.[2] This analysis is designed to estimate the change in GHG emissions that would occur if oil sands replaced the average sources of crude oil in US refineries. If oil sands replaced crudes with GHG emissions higher than the US average, the impact on emissions would be correspondingly lower.

1. SCO produces 45 percent lower GHG emissions at the refinery stage than bitumen. However, the combination of upgrading and refining emissions for SCO exceeds the value for bitumen.
2. The estimated life-cycle emissions for the average crude consumed in the United States are sourced from a November 2008 paper written by DOE/NETL, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels.*

## Scale of Oil Sands Emissions in a Canadian and Global Context

IHS CERA estimates that in 2009 carbon dioxide ($CO_2$) emissions from oil sands extraction and upgrading constituted about 14 percent of Alberta's emissions, 6 percent of Canada's emissions, and 0.1 percent of global emissions. Emissions from oil sands production are not the largest source of emissions in Alberta or Canada as a whole. Canadian emissions from transportation (27 percent), total emissions from the energy extraction sector (28 percent—the oil sands account for 6 percent), and electrical generation (17 percent) each constitute a larger portion of total emissions than oil sands.*

As oil sands productive capacity increases, GHG emissions will grow as well. Looking forward, IHS CERA's oil sands scenarios envision that emissions from oil sands will grow from 6 percent of Canada's emissions today to between 14 (3.1 mbd moderate growth case) to 21 percent (5.7 mbd stretch growth case) by 2030.** The GHG intensity of each barrel of oil sands production is projected to decline more than 10 percent over the next 20 years, but growth in the number of barrels produced results in emissions growth.***

By 2030 in the stretch growth scenario emissions from oil sands would be in the range of those from Canada's electrical generation sector, but still lower than emissions from the transportation sector. In absolute terms emissions resulting from oil sands production and upgrading are projected to grow from about 34 million metric tons of carbon dioxide equivalent ($mtCO_2e$) in 2009 to between 70 (moderate growth case) to 160 (stretch growth case) $mtCO_2e$ by 2030. To help put the emissions in perspective, the US currently produces domestically 4.5 mbd of crude oil creating about 45 $mtCO_2e$ annually. Natural gas–fired electricity generated in the United States results in more than 360 $mtCO_2e$ per year. To be sure, oil extraction and refining from any oil supply source requires energy. If oil sands were to be substituted with another source of oil supply, one that produces the average life-cycle emissions of the oil consumed in the United States, the resulting well-to-wheels emissions would be about 5 to 15 percent lower.

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*Total energy extraction sector includes all oil extraction (including oil sands), refining, mining, and related fugitive emissions. The sector emissions data is sourced from the 2007 Canadian National Inventory Report, Environment Canada, April 2009.

**The high growth scenario is a "stretch case" for oil sands growth and assumes a middle-of-the road $CO_2$ policy. The scenario assumes growth in coke gasification as an alternative to natural gas and oil sands production of 5.7 mbd by 2030. The moderate growth case assumes aggressive $CO_2$ policy, aggressive carbon capture and storage, introduction of alternative nonsteam technologies for production, and oil sands production of 3.1 mbd by 2030. Today's emissions are estimated based on 2009 data and production growth.

***See the IHS CERA Special Report *Growth in the Canadian Oil Sands: Finding the New Balance.*

# PART III: CHALLENGES OF LIFE-CYCLE ANALYSIS

Evaluating and comparing the life-cycle GHG emissions of fuels is a complex process given differences in the data used and in the types of inputs considered. Estimates attained from rules of thumb or broad assessments can be helpful for general discussion, but they are not specific enough to support sound public policy.

The challenge of accurately measuring or estimating life-cycle emissions is reflected in the wide range of results across the studies analyzed. Across the 13 sources compared, estimates of the well-to-retail pump emissions for specific crude oils varied by as much as 45 percent. The significant difference in results reflects the level of uncertainty in measuring life-cycle GHG emissions and highlights a challenge in regulating LCFS policies. Inconsistencies in the results arise from a variety of sources:

- **Data quality, availability, and modeling assumptions.** Often the data used in life-cycle analysis are average values or numbers estimated from limited sources. The assumptions about key data and calculations are often not transparent, differing substantially among the various models and studies. Emissions also vary from a specific fuel source over time.
- **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 (see Figure 6).
- **System boundary for life-cycle estimates.** Estimates of life-cycle emissions require a system boundary—a determination of what emissions are counted and not counted. Emissions directly attributable to production of the product are included, but studies vary on whether they include secondary or indirect emissions.

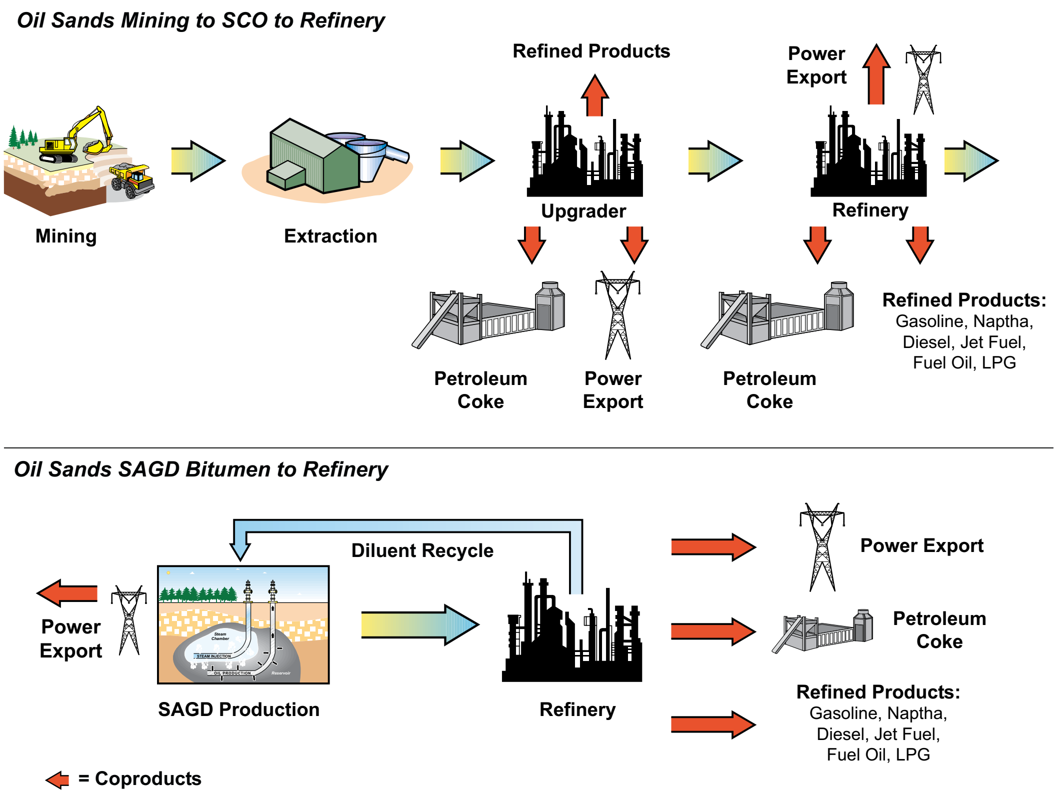
## DATA QUALITY, AVAILABILITY, AND MODELING ASSUMPTIONS

The data used in crude oil life-cycle analysis pose a number of challenges. Data are often derived from rules of thumb or estimated from limited sources. Even for a single source of crude oil, such as West Texas Intermediate, a range of life-cycle GHG emissions values have been calculated. Often sufficiently granular and current data to estimate life-cycle GHG emissions are not publically available. Moreover the GHG emissions profile of producing a crude oil can change significantly over time. As a crude oil reservoir matures, more energy-intensive production methods are often required, resulting in greater life-cycle GHG emissions.

Blends of crude oil and imports of refined products are particularly problematic for emissions estimates. Crudes with similar properties are often combined in pipelines, making it difficult to track the actual source of the crude oil. With oil sands, bitumen blends can be dilbit or syndilbit (a combination of diluents, SCO, and bitumen), and some blends even contain

**Figure 6**

**Allocation of Emissions to Coproducts: Oil Sands Examples**




Source: IHS CERA.
Note: LPG = liquified petroleum gases.
00706-6

conventional oil. This example illustrates that blending results in substantial changes in the GHG emissions, and keeping track of the emissions associated with each of the components is not always straightforward. The problem persists with imports of refined products; there is no system in place to track the original crude oils.

Furthermore some GHG emissions are difficult to measure. For example, a source of variance in estimates for oil sands mining is introduced in quantifying the amount of methane released from tailings ponds and the mine face. Methane release estimates (and the corresponding effect on GHG emissions) are usually included in published GHG estimates for mining operations. However, there is considerable uncertainty in quantifying the extent of the methane release; assumptions vary from 10 percent to more than 25 percent of the production emissions from mining.[1]

Even when precise data can be gathered, differences among the various models used to calculate the resulting GHG emissions create further variance in results. Numerous models

1. These values are taken from the applications for approval for future mining operations to the Alberta Energy Resources Conservation Board.

are used to calculate life-cycle emissions, each with their own correlations, factors, and assumptions, resulting in a range of GHG emission estimates from the same input data.

The quality or lack of international data used in life-cycle analysis poses an additional challenge. Without accurate and verifiable data, some sources of crude oil, such as Canadian oil sands, could be unduly penalized for being more transparent about their GHG emissions than other sources. If policies that target life-cycle emissions use inaccurate assumptions, instead of reducing emissions they could shift emissions to countries or sectors with mischaracterized levels of GHG emissions. Today the United States imports crude oil from over 40 countries, and most of these countries provide multiple types of crude oil. Measuring, verifying, and tracking the emissions from each crude source would be a formidable effort.

Since the band of uncertainty in measuring life-cycle emissions is larger than the emissions reductions that regulations are aiming to achieve, determining whether a regulation is meeting its environmental goals will be difficult. Regulation can be established based on a specified model and its assumptions to provide regulatory certainty to fuel producers, but the actual environmental result of the regulation will always be difficult to determine.

## ALLOCATION OF EMISSIONS TO COPRODUCTS: THE EXAMPLE OF ELECTRICITY COGENERATION

Emissions allocation challenges can arise in a number of ways in petroleum life-cycle analysis. Allocation of upstream emissions and refinery emissions among the various refined products is one challenge. Cogeneration of electricity (production of electricity along with steam) poses an even greater challenge. Allocating the emissions between steam and electricity is one part of the quandary; the magnitude of GHG credit to grant the produced electricity is another.

Gas-fired cogeneration of electricity is a common practice in the oil sands industry because it decreases costs and provides a reliable power supply. All mining production and about half of in-situ production currently use cogeneration, and this proportion will increase as SAGD production grows. Because cogeneration plants simultaneously produce steam and electricity, they are more efficient than producing steam and electricity separately. Consequently, sites with electrical cogeneration plants have lower life-cycle GHG emissions then comparable sites that buy their electricity from the grid.

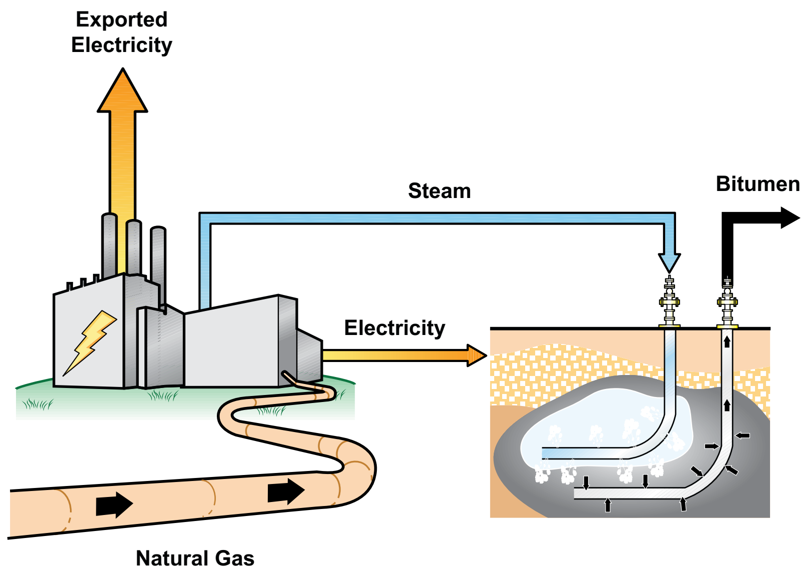
Cogeneration facilities for oil sands developments are sized to produce enough steam to meet oil production needs. Sizing the plant this way results in a surplus of electricity that can be sent to the grid for use off-site (see Figure 7). This power sold to the grid is very reliable, since the cogeneration plant must run at all times for oil production to continue.

In Alberta the electricity produced by natural gas cogeneration is typically less carbon-intensive than the grid electricity that it replaces.[1] In this case the GHG emissions for producing a barrel of bitumen with cogeneration are 8 to 14 percent lower than the emissions from a comparable operation without cogeneration. The size of the reduction varies with

1. Today, about 60 percent of Alberta's power is generated from coal. Power from coal is more carbon-intensive than power generated from natural gas. Source for electrical generation mix: Alberta Electric System Operator.

**Figure 7**

**Cogeneration for In-situ Production**




Source: IHS CERA.
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the assumption on the source of electricity displaced. A 14 percent reduction results from assuming the electricity displaces coal-fired power generation.[1] An 8 percent reduction results from using the renewable offset credit established by the Alberta government.[2] An estimate using the average GHG intensity for Alberta's grid produces a result in between these two extremes.[3] Using this range of potential offset values, on a well-to-wheels basis, cogeneration reduces the life-cycle GHG emissions for producing refined products with a barrel of bitumen using SAGD by 1 to 2 percent.[4]

Although oil sands operators could produce more steam (and hence electricity) than their sites require for oil production, they usually do not; they are not in the electrical generation business. However, there are a handful of examples of oversized cogeneration plants in the oil sands.[5] In some cases the oversized cogeneration plants have been built to fit future production growth. Therefore they are "oversized" now but may not be in the future. For these oversized

1. Coal GHG intensity for power generation is assumed to average 1,000 kilograms (kg) $CO_2$ per megawatt-hour (MWh) which is the average between a "best in class" new coal plant and a marginal coal plant.
2. Alberta's GHG intensity offset credit for renewable power generation is 650 kg $CO_2$ per MWh. Offset Credit Project Guidance Document, Alberta Government, February 2008.
3. Alberta's average grid GHG intensity was 820 kg $CO_2$ per MWh in 2007. 2007 Canadian National Inventory Report, Environment Canada, April.
4. All calculations are for a SAGD site with a steam-oil ratio of 3 which is the current average for all SAGD operations, and electricity export equivalent to 10 kilowatt-hour per barrel of bitumen produced. The percent reduction associated with cogen varies with the steam-oil ratio.
5. Cogeneration plants that produce as much as ten times more power than needed to meet oil production requirements.

facilities additional GHG emission reductions are possible—for instance if they replace electricity generated from coal. However, as the oversized portion of the cogeneration plant is effectively a power plant (the excess steam is not required for oil production), not all of these extra emissions reductions can be attributed to the bitumen barrel produced. The way that government policies calculate and credit GHG reductions resulting from cogeneration strongly influences facility investments in cogeneration. In California there are examples of developments using steam for heavy oil recovery with cogeneration plants that produce much more steam than is needed for oil recovery. These facilities were designed to take advantage of a past US federal government policy that allowed cogeneration plants to sell electric generation in excess of their needs to the grid at prices typically higher than their cost of production. One example produces more than 20 times more electricity per barrel than the typical in-situ cogeneration plant in Alberta, where cogeneration plants are not so heavily subsidized.

## SYSTEM BOUNDARY: EXAMPLE OF DIRECT AND INDIRECT LAND USE CHANGES

Life-cycle analysis attempts to estimate all of the GHG emissions associated with producing and using a given product. However, including all of the emissions is clearly an impossible task. Life-cycle analyses establish a system boundary—a determination of what types of emissions are included and not included in the analysis. As the system boundary widens, the level of debate and uncertainty in the resulting GHG emission estimate tends to grow. However, a narrow system boundary may result in excluding significant sources of GHG emissions.

In estimating the GHG emissions for petroleum, the system boundary is often drawn tightly around the production facilities and the refinery. Direct emissions that are beyond the facility gate are generally not included, nor are indirect emissions. As an example, life-cycle analyses of oil sands include the GHG emitted when water is heated to remove bitumen from the sands. However, emissions resulting from the production of natural gas used in the steam boiler are not included (direct off-site emissions), nor are emissions resulting from boiler production (indirect emissions).

The issue of GHG emissions resulting from land use change is a particularly strong area of debate. Such emissions are very difficult to measure and to attribute to products.

For oil and gas developments, direct emissions from land use change arise when the 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 disturbed land is released; others result from loss of vegetation on the land, which absorbs carbon as it grows.

In the case of biofuel production, the GHG emission changes from land use can be direct or indirect. Direct emissions can occur when soil is disturbed to plant biofuel crops and if the biofuel crop absorbs less $CO_2$ than the previous use of the land. Indirect emissions can occur when the increased production of biofuel feedstocks results in the conversion of additional land to agriculture to meet the ongoing demand for food. All land use emissions are difficult to estimate, but indirect emissions are particularly difficult to estimate and attribute to products. Estimating just how land use changes due to increasing biofuel production is difficult, and the uncertain nature of emissions resulting from land use changes adds another layer of ambiguity.

Whether and how to include land-use change emissions in life-cycle analysis is the topic of controversy in biofuels regulation. California's LCFS and the US RFS2 include indirect emissions due to land use change in their life-cycle emissions for biofuels. British Columbia made the opposite decision and does not consider emissions due to indirect land use change. Land use change emissions for petroleum fuels are not included in either regulation. The inclusion of emissions due to land use change makes a substantial difference in total life-cycle emissions for biofuels. For example, land use change makes up as much as two thirds of the total life-cycle emission for some biofuels in California's LCFS analysis.

Unlike for biofuels, the effect of excluding land use change emissions in the life-cycle analysis for conventional petroleum is relatively minor. The amount of land disturbed per unit of energy produced is much smaller than for biofuels. However, emissions from land use change can be larger from oil sands developments than from other sources of crude oil. For mining operations, all of the vegetation and overburden is removed, disturbing a much larger area per unit of energy produced than a conventional oil field. Additionally, the oil sands region has numerous peat bogs that absorb large amounts of carbon compared with forest or prairie land. Disturbing this land results in larger GHG emissions per acre than most oil developments. Emissions from land use change for in-situ projects are much smaller than for mining because less land is disturbed.

Methods to accurately measure the amount of carbon stored and released by land disturbed during oil and gas development are still evolving. For instance when an oil sands mine is stripped, not all of the carbon is released to the atmosphere, and estimating what portion of the carbon is released is not easy. After the land is reclaimed, the land will start sequestering carbon again. If the land can be reclaimed as peat bog, it could sequester a similar amount of carbon as before disturbance. Currently most studies do not include a credit for future sequestration because restoration of peaty wetlands has not been successfully demonstrated to date. Recently a handful of studies have attempted to quantify the direct land-use–related GHG emissions of oil sands.[1] Using average values across the wide range of study results (estimates of stored carbon varied by more than 200 percent) showed that including the direct land impacts for in-situ projects does not result in a material change in GHG life-cycle emissions. However, for oil sands mining the direct land impacts could potentially increase the well-to-wheels emissions from an average of 6 percent higher than the average crude consumed in the United States to about 12 percent higher. These numbers aid in understanding the possible effect of including direct land use in GHG emission calculations; but like all estimates of emissions associated with land use change, they are highly uncertain.

Widening the system boundary increases the uncertainty in GHG life-cycle analysis, but it also can provide more complete accounting of the emissions created by use of a transportation

1. "Bitumen and Biocarbon Land Use Conversations and Loss of Biological Caron Due to Bitumen Operations in the boreal Forests of Alberta Canada," Global Forest Watch, 2009; "Biological Carbon Emissions Intensity of Oil Sands mining," Canadian Boreal Initiative/Ducks Unlimited Canada; "Land Use Greenhouse Gas Emissions from Conventional and Unconventional Oil Production", University of California, Davis, April 2010 (authors in this study are also from Stanford University, University of Guelph, University of Calgary, and Drexel University).

fuel. Furthermore, when comparing life-cycle assessments for different sources of fuel, a consistent system boundary is crucial, although difficult to establish.

# PART IV: IMPLICATIONS OF LIFE-CYCLE POLICY ON OIL SANDS

The life cycle of petroleum fuels and the way that GHGs are emitted make reducing their GHG intensity difficult. GHGs are emitted during oil production, crude oil transportation, fuel refining, and fuel transportation to the final user, but 70 to 80 percent of life-cycle GHG emissions for petroleum fuels occur in the combustion phase. This fact has crucial implications for complying with life-cycle–based regulations, including LCFS.

GHG emissions from combustion are an unavoidable result of using petroleum fuels. More efficient vehicles reduce the combustion emissions *per mile driven*. However, no mitigation strategy for petroleum-fueled vehicles can reduce emissions *per unit of energy,* which is the basis of LCFS. For this reason the 70 to 80 percent of the total life-cycle emissions that occur in the combustion part of the value chain for petroleum fuels are "off the table" with respect to LCFS compliance. Thus the 10 percent reduction in life-cycle GHG intensity that the California and British Columbia LCFS require would all have to occur in the noncombustion, or well-to-retail pump, part of the life cycle. This would mean a reduction of approximately one-third to one-half of the GHG emissions from the oil well to the retail pump. This level of reduction is extremely difficult to achieve in an industry already under competitive pressure to reduce energy use and costs. Using crude oil sources with lower-than-average upstream GHG emissions and increasing refinery efficiency can reduce the life-cycle GHG emissions of gasoline or diesel, but not by 10 percent.

This challenge is present not just for high-emissions crudes, such as oil sands, but for all sources of crude oil. Ultimately the goal of LCFS is to displace *petroleum* in the transportation sector with alternative fuels that have lower emissions.

## HOW DO LCFS DEAL WITH HIGH-CARBON CRUDES?

The way an LCFS is written determines whether oil sands and other high-emissions crudes are disproportionately displaced under LCFS. There are two ways to deal with different sources of crude oil—differentiating among sources of crude oil or using a standard value for all petroleum fuels. California and British Columbia provide examples of the two methods.

The California LCFS differentiates among sources of crude oil, to a point. It establishes a baseline emissions intensity for gasoline and diesel fuel produced from crudes already used in California refineries.[1] Refiners using new sources of crude oil with upstream emissions greater than 15 grams of $CO_2$ equivalent ($gCO_2e$) per megajoule (MJ) cannot use the baseline emissions value and must establish an emissions-intensity value for these higher emissions crudes. For comparison, the average crude oil refined in California today has upstream emissions of about 8 $gCO_2e$ per MJ, while oil sands crudes vary from approximately 13 to 19 $gCO_2e$ per MJ. Crudes with upstream emissions below the threshold or those already refined in the state can use the baseline value. Refiners can also petition to use an emissions intensity smaller than the baseline value if they use low-emissions crudes or improve the

1. California's baseline basket of crudes consists of all sources of crude oil that made up 2 percent or more of California refineries' feedstock in 2007.

efficiency of their processes. However, such petitions must result in at least a 5 $gCO_2e$ per MJ improvement in GHG intensity, a significant increase in the well-to-retail pump portion of the value chain.

California's method of differentiating among crudes is controversial, since high-emissions crudes already used in the state are "grandfathered in," and refiners do not have to account for the higher emissions of these crudes under the LCFS, even if their share of crude supply increases. Canadian officials have expressed concern that this method discriminates against oil sands crudes as compared to California's own high-emissions crude oil, potentially violating provisions of the North American Free Trade Agreement and the World Trade Organization.

British Columbia's LCFS takes a different and simpler approach. It assumes that life-cycle GHG emissions from all sources of gasoline and diesel are the same. Refineries do not have to vary the emissions values they use based on their sources of crude oil. However, the British Columbia LCFS does not incentivize refiners to switch to lower-emissions crudes or to pursue energy efficiency improvements to reduce the life-cycle emissions of their products. The only compliance mechanism is replacing petroleum with a lower-carbon fuel source.

The choice to differentiate among different types of crude oil comes down to balancing the complexity of the regulation with the level of certainty that its environmental goals will be met. Keeping track of the types and quantities of crude oil that refineries use and establishing life-cycle GHG emissions estimates for high-emissions crude oils are substantial efforts—and could prove quite challenging particularly in terms of accuracy and keeping pace with changing life-cycle emissions. Emissions from different sources of crude oil vary, both across fields and in a particular field over time. Field-level data on life-cycle GHG emissions are very spotty and require a great deal of estimation, resulting in considerable uncertainty in the life-cycle emissions of all crude oil sources. Additionally, crude oils of similar quality are mixed in the pipeline distribution system, although their life-cycle GHG emissions could be quite different depending on how and where the crudes were produced.

The British Columbia policy of assigning one value each to gasoline and diesel sidesteps the issue of keeping track of various crudes and their emissions value. However, the trade-off is that such a regulation is less certain to meet its GHG emissions reduction goals. If the crude oil refined to produce fuel for sale in British Columbia were to become more carbon-intensive on average, this increase in emissions would not be captured under the LCFS. In this case emissions would decline less than called for in British Columbia's LCFS.

## HOW DO HIGH-CARBON CRUDES FIT INTO AN LCFS WORLD?

Since a 10 percent reduction in life-cycle GHG emissions from petroleum fuels is difficult to achieve, in practice LCFS are alternative fuel standards. British Columbia's LCFS takes on this point directly by using one life-cycle emissions value for all sources of petroleum fuels. The primary method of compliance with LCFS is to replace petroleum with other types of fuel, resulting in fewer GHG emissions. Compliance with LCFS is likely to rely on increasing consumption of second generation biofuels and electricity in transportation (see

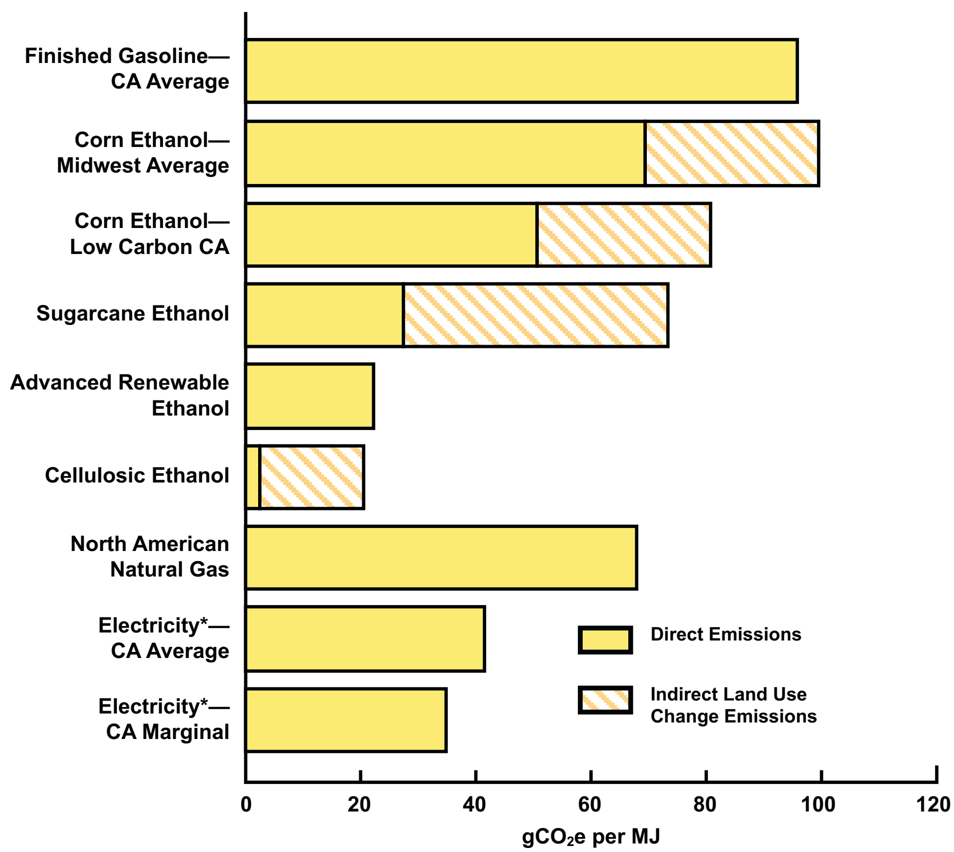
Figure 8).[1] More efficient vehicles that run on petroleum do not help with LCFS compliance, since these regulations focus on the emissions from the fuel itself per unit of energy.

California's LCFS allows providers of transportation fuels that exceed LCFS compliance standards to trade compliance credits with providers who need them. Petroleum and biofuel providers are required to comply with LCFS. Electric utilities, natural gas companies, and hydrogen producers, which sell fuels that already have lower GHG intensity than gasoline or diesel, can opt in to the program to provide transportation fuel and to sell credits to producers of fuels with higher GHG intensities. Other LCFS are less specific in their trading mechanisms but are likely to adopt similar systems to simplify compliance.

**Figure 8**

**Life-cycle GHG Emissions of Various Fuels**

(CARB estimates)




Source: IHS CERA and California Air Resource Board (CARB).
*Includes electric vehicle drivetrain efficiency adjustment factor.
00110-4

1. The amount of GHG reduction from using electricity in transportation depends on the source of the electricity. Coal-fired electricity can even result in an increase in life-cycle GHG emissions over gasoline.

To illustrate the options and challenges of LCFS, consider the compliance options for a provider of 100,000 barrels per day (bd) each of gasoline and diesel in California. What LCFS-compliant fuel portfolios could the supplier assemble, either through producing or acquiring fuels or purchasing credits?

By 2020 our hypothetical fuel provider would be required to sell fuels into the gasoline and diesel pools that emit 10 percent less GHG on a well-to-wheels basis than today's baselines.[1] Various portfolios of fuels could allow our supplier to comply with the LCFS. The gasoline and diesel pools are considered separately, so substituting diesel for gasoline is not a compliance option.

For the gasoline pool, compliance options include substituting volumes of gasoline with sugarcane ethanol, cellulosic ethanol, electricity, or some combination of these fuels. Ethanol derived from corn, the most common biofuel in the United States today, is not included in the analysis. On a life-cycle basis corn ethanol GHG emissions vary from slightly greater to around 10 percent less than those from gasoline. Therefore even a total replacement of gasoline-pool fuel with corn ethanol might not achieve compliance, depending on the source of the ethanol. Figure 9 shows the results of this analysis considering the average fuel processed in California as well as crude oil derived entirely from Canadian oil sands.

This analysis shows that achieving LCFS compliance for the gasoline fleet requires new technology and changes in fuel distribution and the vehicle fleet regardless of the source of crude oil. Sugarcane ethanol can help a fuel portfolio comply, but owing to its relatively high life-cycle emissions, it would need to replace a large portion of petroleum in the gasoline pool. In this case flex-fuel vehicles capable of consuming fuel containing a high percentage of ethanol would be essential. Additional infrastructure would also be necessary, as few refueling stations carry the fuel (new tanks and pumps would be required). Cellulosic ethanol would displace much less petroleum because of its smaller life-cycle emissions, but this fuel is not yet available in commercial quantities. Electricity is another route to compliance, but electricity is likely to be only a small part of a compliance portfolio in the next ten-plus years because of high electric vehicle costs and still-challenging technology issues.

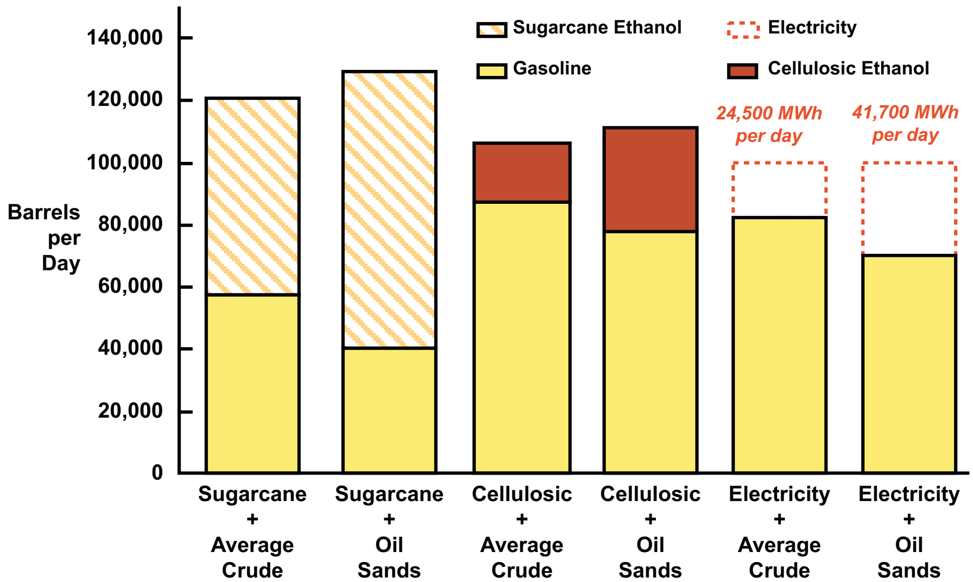
An analysis for diesel compliance reveals an even greater challenge, as fewer low-carbon fuel options are available (see Figure 10). Similar to ethanol derived from corn, biodiesel derived from soybeans does not have low enough life-cycle emissions to be helpful for LCFS compliance. Biodiesel derived from waste oil is a good blending fuel for LCFS compliance, since its low emissions allow a relatively low blending ratio and since it can be run in today's vehicles and transported via today's infrastructure. However, feedstock availability is likely to limit the amount of waste-oil–derived biodiesel. Compressed natural gas (CNG) and liquefied natural gas are additional options for fueling the heavy-duty vehicle fleet that accounts for the lion's share of US diesel demand. A large portion of the heavy-duty diesel fleet would need to be converted to natural gas, however, an outcome that IHS CERA deems unlikely.[2]

1. The 10 percent reductions correspond to emissions limits of 86.3 $gCO_2e$ per MJ for gasoline and 85.2 $gCO_2$ per MJ for diesel.
2. See the IHS CERA Multiclient study *Fueling North America's Energy Future.* Barriers to large-scale adoption of natural gas for heavy-duty transportation compared with diesel include higher vehicle capital costs, lower fuel density resulting in more refueling stops, and lack of refueling infrastructure.

**Figure 9**

**Example Gasoline Pool Portfolios that Comply with the California LCFS in 2020**

(100,000 bd of gasoline equivalent)




Source: IHS CERA.
Notes: Compliant portfolios can consist of multiple alternative fuels, and combining multiple fuels is the most likely compliance strategy. Volume of portfolios that contain ethanol are larger than 100,000 barrels because of ethanol's lower energy density.
00706-7

In practice LCFS are aggressive alternative fuel standards. Significant quantities of low-carbon fuels will be needed to meet the 2020 mandates. A good rule of thumb is that blending LCFS-compliant transportation fuels made from oil sands crudes will require twice the quantity of low-carbon fuels as the average. The life-cycle GHG emissions from oil sands products are about 10 percent higher than the average crude and thus require twice the offset to reach a 10 percent reduction from the average.[1] Highlights of potential compliance hurdles include the following:

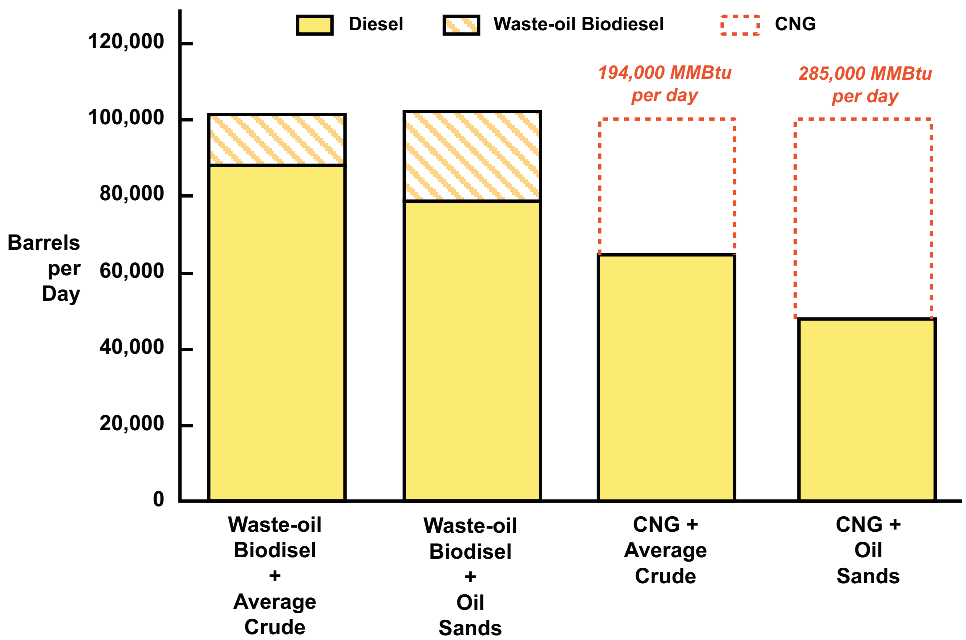
- **LCFS gasoline pool compliance could be challenged by limited availability of low-carbon ethanol.** To comply with the California LCFS gasoline target using only sugarcane ethanol and California average crude oil, more than 50 percent of the gasoline consumed (on a volume basis) would need to be derived from sugarcane ethanol. Today California consumes about 1 mbd of gasoline, and Brazil produces less than 0.5 mbd of sugarcane ethanol. Meeting a 10 percent reduction target today would require more sugarcane ethanol than Brazil currently produces. Compliance with cellulosic ethanol

1. This analysis considers the effect of LCFS policy on 100 percent oil sands products. It does not consider bitumen blends such as dilbit. Because dilbit has lower life-cycle GHG emissions, the amount of alternative fuels required to comply would be lower.

Figure 10

Example of Diesel Pool Portfolios that Comply with the California LCFS in 2020

(100,000 bd of gasoline equivalent)




Source: IHS CERA.
Note: Compliant portfolios can consist of multiple alternative fuels, and combining multiple fuels is the most likely compliance strategy.
00706-8

requires smaller volumes because of its lower emissions, but cellulosic ethanol is not yet produced commercially.

- **LCFS is more aggressive than RFS2.** RFS2 requires more than 20 percent of projected US gasoline demand (on a volume basis) be met by biofuels by 2022, and more than half of this volume must be cellulosic and advanced biofuel. LCFS requirements for biofuel are even greater when considered as a percentage of fuel demand. IHS CERA projects that in a future scenario with low growth in US petroleum demand and strong adoption of alternative fuels and vehicles, the volume of biofuel consumed would still fall short of the less ambitious RFS2 mandate. EPA recently reduced the volume of cellulosic ethanol required in 2011 because sufficient fuel is not expected to be available.

- **Slow turnover in the vehicle fleet will complicate LCFS compliance.** The fleet of existing vehicles turns over slowly—a typical car is on the road for 12 to 15 years before it is replaced. Therefore, both the electricity and flex-fuel vehicle options for LCFS gasoline pool compliance pose a challenge in the ten-year time frame. Electric vehicle options, such as plug-in hybrid electric vehicles (PHEVs) and all-electric vehicles, are only now becoming available to consumers.[1] Even with a sharp increase in the sales of alternative vehicles, the number of cars and trucks able to consume alternative fuels are likely to constrain the volumes of low-carbon fuel that can be consumed. In IHS CERA's aggressive alternative vehicles scenario, electric vehicles displace less than 100,000 bd of US gasoline demand by 2020.

- **LCFS diesel pool compliance is limited due to a lack of viable low-carbon fuel alternatives.** Low carbon alternatives to diesel are not expected to arrive over the next decade or two. Although viable biodiesel from waste oil does comply, volumes are limited, and natural gas alternatives for heavy hauling are unlikely.

Clearly oil sands crudes are even more challenged than the California average crude in complying with LCFS. They require about twice the quantity of low-carbon alternative fuels to achieve a 10 percent reduction in life-cycle emissions. However, only time will tell what the ultimate impact of LCFS policies on the market for oil sands and other carbon-intensive crudes will be. Since nearly all sources of crude oil will fall short of the LCFS target, research on alternative vehicles and fuels will continue. Future innovations could help these low-carbon fuel alternatives to become both competitive and scalable.

The cost and availability of next-generation biofuels and electric vehicles will be important factors in how fuel providers comply with LCFS. High-carbon sources of transportation fuel, including oil sands and other sources of crude oil, can fit into an LCFS system as part of a fuel portfolio if sufficient volumes of low carbon alternatives are both economic and available. To achieve compliance, other low-carbon fuels in the portfolio must offset the higher emissions from petroleum fuels.

## CONCLUSION: THE PATH TO COMPLIANCE

Life-cycle analysis is an evolving discipline that must deal with a number of uncertainties, making it a challenging basis for policy. Estimates of well-to-retail pump GHG emissions from a single fuel can vary by more than 10 percent on a well-to-wheels basis. This variance is larger than the GHG emissions reductions that some LCFS require. Regulatory uncertainty for fuel producers can be limited by establishing life-cycle emissions values in regulation, but uncertainty about the environmental efficacy of such regulations remains. However, life-cycle analysis will never be perfect, and regulations can change over time to reflect the latest findings.

An additional challenge in regulating transportation fuels according to their life-cycle GHG emissions is the trade-off between the complexity of a regulation and the level of incentive that it provides for emissions reductions. Establishing broad categories of fuels makes a regulation much easier to manage, but also reduces the incentive for fuel producers to make additional changes in their processes or feedstocks to reduce their GHG emissions. More granular regulations do provide such incentives, but at the expense of a much more complex regulatory system and the challenge of keeping track of various fuels that are nearly identical chemically but that may have quite different life-cycle GHG emissions.

1. PHEVs have an all-electric range large enough to handle most day-to-day driving, with a backup conventional fuel tank to ensure a range as great or greater than that of a gasoline vehicle.

Over the next decade LCFS compliance will be difficult for all crude oil sources. Fitting oil sands crudes into an LCFS-compliant fuel portfolio is more challenging because of their greater life-cycle emissions. Over time, assuming that the economics and availably of low-carbon alternatives such as next generation biofuels and electric vehicles improve, it is possible there will be sufficient volumes of alternative fuels to offset the higher carbon intensity of oil sands. The ultimate effect of LCFS on the market for oil sands crudes will depend on the advancement of these fuels and the vehicles that use them.

## REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Calgary (May 14, 2010) providing an opportunity for oil sands stakeholders to come together and discuss perspectives on the key issues related to oil sands, life-cycle analysis, and life-cycle analysis policy. 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.

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## IHS CERA TEAM

**David Hobbs, IHS CERA Chief Energy Strategist**, is an expert in energy industry structure and strategies. He previously managed IHS CERA's energy research activities. Mr. Hobbs is a principal author of the major IHS CERA studies *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda*, a comprehensive examination of the impact of the changed natural gas supply outlook on energy markets, power generation technology choices, and the challenges of procuring a low carbon future; *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures* and *Modernizing Oil and Gas Disclosures*, comprehensive analyses of the problem of assessing oil and gas reserves and resulting proposed solutions; *"Recession Shock": The Impact of the Economic and Financial Crisis on the Oil Market*, a major IHS CERA assessment of the world economic crisis; and of the IHS CERA Multiclient Study *Harnessing the Storm—Investment Challenges and the Future of the Oil Value Chain*. He was a project advisor to the IHS CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.*

Mr. Hobbs is IHS CERA's representative on the management board of the Global Energy Executive MBA program run jointly between the Haskayne School of Business and IHS CERA. He is also a member of the Scientific Advisory Board of the Fondazione Eni Enrico Mattei. Prior to joining IHS CERA Mr. Hobbs had two decades of experience in the international exploration and production business. He has directed projects in Asia, South America, North America, and the North Sea. He has led major international investment and asset commercialization operations. Based in Cambridge, Massachusetts, Mr. Hobbs holds a degree from Imperial College.

**James Burkhard, Managing Director of IHS CERA's Global Oil Group,** leads the team of IHS CERA experts who analyze and assess upstream and downstream market conditions and business strategies. His team also develops and maintains detailed short- and long-term outlooks for global crude oil and refined products markets. Mr. Burkhard's expertise covers geopolitics, world energy and economic conditions, and global oil demand and supply trends. He works closely with IHS CERA clients in assessing how market, economic, and political risks could change the competitive environment. He also works with companies to assess business opportunities in both the upstream and downstream sectors. Mr. Burkhard was the project director of *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030*, a comprehensive IHS CERA study encompassing the oil, gas, and electricity sectors. He is currently leading a new initiative, the IHS Global Scenarios to 2030, which covers global economics, security, and geopolitics, and is focused on the energy and automotive industries. He was also the director and coauthor of the recent IHS CERA Multiclient Studies *Growth in the Canadian Oil Sands? Finding the New Balance* and *Potential versus Reality: West African Oil and Gas to 2020*. He was project advisor to the IHS CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy*. Mr. Burkhard is also the coauthor of CERA's respected *World Oil Watch*, which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths about Energy*. Before joining IHS CERA Mr. Burkhard directed infrastructure projects in West Africa for the United States Peace Corps and was a field operator for Rod Electric. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

**Samantha Gross, IHS CERA Director**, focuses on the interaction of investment decision-making with the complex landscape of governments, nongovernmental organizations, shareholders, and other stakeholders. She is the manager of IHS CERA's Global Energy service. She led the environmental and social aspects of CERA's recent study *Growth in the Canadian Oil Sands: Finding the New Balance*, including consideration of water use and quality, local community impacts, and aboriginal issues. Ms. Gross was also the IHS CERA project manager for *Towards a More Energy Efficient World* and *Thirsty Energy: Water and Energy in the 21st Century*, both produced in conjunction with the World Economic Forum. Additional contributions to IHS CERA research include reports on the water impacts of unconventional gas production, international climate change negotiations, US vehicle fuel efficiency regulations, and the California low-carbon fuel standard. Before joining IHS CERA she 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.

**Jackie Forrest, IHS CERA Director, Global Oil**, was the Study Manager for IHS CERA's recent Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance.* Ms. Forrest has more than a decade's experience in the definition and economic evaluation of refining and oil sands projects. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products. As the research lead for IHS CERA's Oil Sands Energy Dialogue and Capital Costs Analysis Forum—Downstream, she is responsible for analyzing and monitoring emerging strategic trends related to oil sands projects. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**Tiffany A. Groode, IHS CERA Associate Director,** leads the research on critical issues for IHS CERA's Driving the Future: Energy for Transportation in the 21st Century Forum. Her expertise includes modeling and analyzing the environmental impacts of ethanol production by performing life-cycle uncertainty analysis as well as assessing the potential scale of bioethanol production from various biomass sources. While working at the Sloan Automotive Laboratory at the Massachusetts Institute of Technology (MIT), Dr. Groode presented her bioethanol results and conclusions to a variety of national government agencies to provide insight for policy decisions. Dr. Groode holds a BS from the University of California, Los Angeles, and an MS and PhD from MIT.

## APPENDIX: IHS CERA'S META-ANALYSIS OF LIFE-CYCLE ANALYSIS STUDIES

IHS CERA's meta-analysis of 13 separate sources aims to present our best estimate of the life-cycle emissions of oil sands products compared to other sources of crude oil.[1]

We consider the results of each study on an "apples-to-apples" basis by converting them to common units and common system boundaries. Some studies calculate only part of the well-to-wheels emissions. In order to compare the sources on a well-to-wheels basis, emissions for each step in crude oil processing are required, including crude production, crude transportation, refining, and product distribution. Other studies report emissions on different basis, per barrel of refined product or per barrel of crude. We used the normalized results of the studies to establish IHS CERA's best estimate of emissions.

### Unit of Measure: GHG Emission Comparison

We express GHG emissions in units of kilograms of carbon dioxide equivalent per barrel of refined product produced, (kg$CO_2$e per barrel of refined products). The definition of refined products is explained in the "Fuel Combustion GHG Emissions" section, below. Some life-cycle analysis studies report GHG emissions on the basis of one barrel of crude oil, gasoline, or diesel. For the studies that reported emissions on a single refined product basis, we used the original studies' assumptions on refined product yields to convert the emissions to a total barrel of refined products basis.

## SETTING CONSISTENT BOUNDARIES FOR COMPARISON

In estimating the GHG emissions for petroleum, our life-cycle analysis boundary is drawn tightly around the gate of the oil production facilities, the refinery, and the shipping pipelines. Direct emissions that are beyond the facility gate are not included, nor are indirect emissions. Many studies did not provide much detail on the boundaries for their analysis, and a tight boundary was assumed for these cases.

One exception to this among the 13 studies we considered was the Jacobs-AERI study. This study included emissions beyond the facility gate, including the upstream emissions from producing natural gas combusted at the oil sands facility and the emissions from producing other fuels that are imported into the refinery, such as isobutene. The Jacobs-AERI study included emissions from these offsite sources for all sources of crude oil. In the case of oil sands production, including these emissions added 12 to 13 percent to well-to-tank emissions,

1. IHS CERA has updated the GHG meta-analysis originally published in May 2009 with data from recent studies that Energy and Environment Solutions, Alberta Innovates (formerly Alberta Energy Research Institute) commissioned: *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy, July 2009 and *Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions,* TIAX LCC, July 2009. Other data sources include: *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels,* DOE/NETL, November 2008; *Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles,* McCann and Associates, November 2001; *Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs,* RAND Corporation, 2008; *Canadian Oil Sands: Opportunities and Challenges,* NEB, 2006. Environmental Challenges and Progress in Canada's Oil Sands, CAPP, 2008; GREET model, Version 1.8b, September 2008; GHGenius: 2007 Crude Oil Production Update, Version 3.8; *2009/10 Sustainability Report,* Syncrude Canada Ltd.; *The Shell Sustainability Report, 2006,* Shell"; IHS CERA data.

or around 3 percent to well-to-wheels emissions. To make the Jacobs-AERI results consistent with the other studies, we excluded these off-site emissions from our meta-analysis.

## APPLYING NORMALIZED VALUES: IHS CERA'S BEST ESTIMATE OF WELL-TO-RETAIL TANK GHG EMISSIONS

To ensure uniformity in crude oil comparisons, we normalized the data.

- **Crude production.** When multiple studies analyzed the same crude, the average value for production-related GHG emissions across the studies was used for the IHS CERA best estimate. If a crude source was considered in only one study, the value from the original study was used directly. Table A-1 summarizes the range of study estimates and our best estimate value.

- **Crude transportation.** The 13 sources used a range of values for the GHG emissions resulting from crude transport. IHS CERA normalized the range of transportation emissions values into two groups—overseas and North American crudes—and used consistent GHG emissions for the transportation step for all comparisons (see Table A-2). Although this is a simplification, because transportation emissions make up less than 1 percent of total well-to-wheels emissions, it does not result in a notable change in the results. Furthermore the range of transportation estimates—even from one location—varied widely. For instance estimates of the emissions for transportation of crude from Mexico ranged from 1 $kgCO_2e$ per barrel to 14 $kgCO_2e$ per barrel. Without normalizing, results for some sources of crude oil could be skewed because the original study author had a conservative or aggressive assumption about transportation emissions compared to others.

- **Refining.** IHS CERA categorized crude oil sources considered in the 13 studies into six categories: light conventional, medium conventional, heavy conventional, extra-heavy conventional, SCO, and bitumen. We calculated the average refining emissions values for each crude type using the study estimates and used these average values for the IHS CERA best estimate (see Table A-3). This is an oversimplification of the complexity associated with refining. In reality the emissions are dependent on the type of refinery that processes the crude, the volume of various refined products produced, the quality of the refinery products, and the crude feedstock. Although these average values are simplified, they do not introduce a significant amount of error on a well-to-wheels basis as the difference between processing heavy crude in a complex refinery versus refining light crude in a simple refinery is less than 2 to 3 percent of the total well-to-wheels emissions. Refining emissions generally make up about 10 percent of well-to-wheels emissions. Additionally, without normalizing the values to be consistent across the crudes compared, the results could be skewed because the original study author assumed a more or less complex refinery compared to other sources.

- **Refined product distribution.** The range of estimates for the GHG emissions associated with refined product distribution varied little among the studies. We used a consistent value across all crude oil sources in our best estimate (see Table A-4).

**Table A-1**

**Summary of Crude Production GHG Emissions, Average Values, and Sources**

| | Average "Crude Oil Production and Upgrading" $KgCO_2e$ per Barrel of Refined Products | Range of "Crude Oil Production and Upgrading" $KgCO_2e$ per Barrel of Refined Products | Sources |
|---|---|---|---|
| CSS Bitumen | 83 | | TIAX-AERI (July 2009) (assumes SOR of 3.35) |
| Canadian Oil Sands: SAGD SCO (Coker) | 116 | 76–133 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009, CAPP 2008 (equivalent to SOR of 3) |
| Middle East Heavy Oil | 98 | | IHS CERA (steam injection assumed) |
| Venezuelan Partial Upgrader | 103 | | McCann (update 2007) |
| Canadian Oil Sands: SAGD Bitumen*** | 69 | 56–80 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009 (equivalent to SOR of 3) |
| California Heavy Oil (ave) | 85 | 63–102 | Jacobs-AERI 2009, TIAX-AERI 2009, IHS CERA |
| Canadian Oil Sands: Mining SCO (Coking) | 80 | 34–122 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009, Syncrude 2009/10, Shell 2006, NEB (2008), CAPP 2008 |
| Nigeria Light Crude (ave) | 82 | 68–93 | McCann 2007, Jacobs AERI 2009, TIAX AERI 2009 |
| Estimated Average Oil Sands Imported to United States (2009) | 66 | | Calculated assuming 55% Dilbit (half from SAGD production and half from CSS) and 45% SCO (from mining production) |
| Canadian Oil Sands: Mining Bitumen | 33 | 23–42 | TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008, Jacobs-AERI 2009, Syncrude 2009/10, Shell 2006, NEB(2008, CAPP 2008 |
| Canadian Oil Sands: SAGD Dilbit | 50 | | Calculated assuming 70% bitumen and 30% natural gas condensate (8 $kgCO_2e$ per barrel assumed for production of condensate) (SOR of 3 for SAGD) |
| Venezuela - Bachaquero (Ave) | 41 | 31–53 | Jacobs-AERI 2009, TIAX-AERI 2009 |
| Canadian Oil Sands: Mining Dilbit | 26 | | Calculated assuming 70% bitumen and 30% natural gas condensate (8 $KgCO_2e$ per barrel assumed for production of condensate) |
| Mexico - Maya (ave) | 32 | 16–43 | DOE/NETL 2008, Jacobs-AERI 2009, TIAX-AERI 2009 |
| Saudi Medium (ave) | 13 | 1-25 | DOE/NETL 2008, Jacobs-AERI 2009 |
| Canadian Heavy (Bow River) | 15 | | TIAX-AERI 2009 |
| West Texas Intermediate | 5 | | TIAX-AERI 2009 |

Source: IHS CERA.
Note: SOR = steam-to-oil ratio.

**Table A-2**

**Summary of Crude Transportation GHG Emissions, Average Values, and Sources**

| | Average "Crude Oil Transportation" $KgCO_2e$ per Barrel of Refined Products | Range of "Crude Oil Transportation" $KgCO_2e$ per Barrel of Refined Products | Sources |
|---|---|---|---|
| Energy consumed to transport any bitumen or crude within North America and Latin America | 5.5 | 1-14 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007, DOE/NETL 2008 |
| Crude transported from rest of the world | 9.1 | 4-14 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007, DOE/NETL 2008 |

Source: IHS CERA.

## FUEL COMBUSTION GHG EMISSIONS

The majority (about 70 to 80 percent) of life-cycle GHG emissions result from fuel combustion. In a complex refinery configured to not make fuel oil, as much as 95 percent of the liquid products yielded from the refinery are diesel, distillate, or gasoline; the remaining products are light liquids such as propane and butane. A complex refinery is defined as a refinery with a coking unit that converts the entire heavy portion of the barrel into light transportation fuels and petroleum coke.

In addition to liquid products, the refinery also yields petroleum coke. The petroleum coke is a by-product of creating the refined products. It can be used for a variety of applications, but the most typical use is in power generation. Because the petroleum coke is a by-product of the refined products and is a substitute for using coal in power generation, the emissions from burning coke are not included in the combustion emissions within this analysis. There are some incremental emissions from substituting petroleum coke instead of coal for power generation, but for the purposes of this comparison, the difference is not considered material enough to have an impact on the comparative results.

To estimate the combustion emissions for one barrel of refined products produced from different crudes in a complex refinery, we apportioned the GHG emissions to the yield of gasoline, diesel, distillate, and gas liquids from each crude (see Table A-5). On average, across a range of heavy, medium, light, SCO, dilbit, and bitumen crudes, the combustion emissions for one barrel of refined products averaged 384 $kgCO_2$ per barrel of refined products (plus or minus 2 percent). Due to the relatively small variance associated with the combustion emissions from the different crude types, an average value was applied to all cases within our comparison. Note, if the petroleum coke was included, the combustion emissions for the average crude would be 432 $kgCO_2$ per barrel of crude.

**Table A-3**

**Summary of Crude Refining GHG Emissions, Average Values, and Sources**

| | Average "Crude Refining" $KgCO_2e$ per Barrel of Refined Products | Range of "Crude Refining" $KgCO_2e$ per Barrel of Refined Products | Sources |
|---|---|---|---|
| Light Conventional Crude (greater than 32 degrees API) | 42 | 30–60 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007 |
| Medium Conventional Crude (greater than 26 to 32 degrees API) | 56 | 44–67 | TIAX-AERI 2009, Jacobs-AERI 2009, McCann 2007, DOE/NETL 2008 |
| Heavy Conventional Crude (greater than 20 to 26 degrees API) | 60 | 47–65 | TIAX-AERI 2009, Jacobs-AERI 2009, DOE/NETL 2008 |
| Extra Heavy (less than 20 degrees API) | 73 | 67–79 | TIAX-AERI 2009, Jacobs-AERI 2009 |
| SCO | 47 | 32–64 | GREET, GHGenius, RAND 2008, CAPP 2008, TIAX-AERI 2009, Jacobs AERI 2009, NEB 2008 |
| Bitumen | 85 | | Jacobs AERI 2009 |
| Dilbit | 70 | | Calculated assuming 70% bitumen and 30% natural gas condensate (30 $kgCO_2e$ per barrel assumed for refining of condensate) |

Source: IHS CERA.

**Table A-4**

**Summary of Refined Product Distribution GHG Emissions, Average Values, and Sources**

| | Average "Crude Oil Refining" $KgCO_2e$ per Barrel of Refined Products | Range of "Crude Oil Refining" $KgCO_2e$ per Barrel of Refined Products | Sources |
|---|---|---|---|
| Distribution from refinery to point of sale | 2.1 | 2–2.6 | TIAX-AERI 2009, Jacobs-AERI 2009, DOE/NETL 2008 |

Source: IHS CERA.

**Table A-5**

**Combustion Emissions for Refined Products**

| Refined Product | $kgCO_2$ per Barrel |
|---|---|
| Gasoline | 375 |
| Diesel/Distillate | 422 |
| Gas Liquids | 231 |

Source: DOE/NETL 2008.

## ESTIMATING GHG EMISSION FOR THE AVERAGE CRUDE CONSUMED IN THE UNITED STATES

The estimated life-cycle emissions for the average crude consumed in the United States are sourced from a November 2008 paper written by DOE/NETL, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*. The paper estimates the average crude extraction emissions by country for top suppliers of crude to the United States in 2005. We calculated the average GHG emissions for extracting the average barrel consumed in the United States by weighting the country-level emissions by the portion of total crude supply from each country.

We calculated the average extraction emissions for a barrel of oil consumed the United States at 39 $kgCO_2e$ per barrel (see Table A-6). The margin of error associated with this estimate is larger than that for any individual crude source, owing to the numerous crude types within each country and the difficulties of modeling and finding data for each crude type.

The following example with oil sands illustrates this point, but this type of complexity is inherent for each country listed. Multiple crudes are produced and blended within each jurisdiction, and it is very difficult to precisely measure each country's average. The oil sands values used in the DOE/NETL study assume extraction emissions of 122 $kgCO_2e$ per barrel for all SCO and 81 $kgCO_2e$ per barrel for all dilbit blends. The average oil sands GHG extraction emissions are calculated using the percent of SCO and dilbit blend imported into the United States in 2005. The oil sands emission estimates are on the high side for these two products—our best estimate values are 80 $kgCO_2e$ per barrel for SCO and between 50 and 60 $kgCO_2e$ per barrel for dilbit. Further, this is a best estimate and not a precise number. Many types of bitumen blends and qualities of SCO are imported, and the available data does not track imports at this level of granularity.

Over time the average crude consumed in the United States is changing. This value is a threshold to compare emissions over time, and it should be viewed as a baseline rather than an absolute or precise measure of the emissions from the average crude consumed within the United States.

The refining and transportation emissions for the average crude consumed within the United States were calculated using assumptions consistent with the normalized data used to compare all other crude sources. For instance, the refinery emissions were calculated by weighting the refining emissions by the portion of US crude supply of each crude type. The transportation

**Table A-6**

**DOE/NETL—Percent of Crude Supplied by Country and Average Emission per Country**

| | Percent of Crude Oil Supplied to US Refineries from Each Location (2005) | Country level $kgCO_2e$ per Barrel Crude Oil Extracted |
|---|---|---|
| Saudi Arabia | 10% | 13.6 |
| Mexico | 11% | 38.4 |
| Venezuela | 9% | 24.2 |
| Nigeria | 8% | 128.6 |
| Iraq | 4% | 19.6 |
| Angola | 3% | 81.8 |
| Ecuador | 2% | 31.3 |
| Algeria | 2% | 35.1 |
| Kuwait | 2% | 16.5 |
| Canadian Crude Oil | | |
| Conventional | 7% | 35.2 |
| Oil Sands (average of SCO and bitumen blends in 2005) | 5% | 104.2 |
| US Domestic | 37% | 24.5 |

Source: IHS CERA.

emissions were calculated considering the percent of supply from within North America and Latin America, and the percent of supply from overseas (see Table A-7).

Not all studies or sources use the same baseline. This is an additional factor that can lead to discrepancies among the results of various studies. For example, the GREET model well-to-wheels emissions for 2005 US diesel is 539 $kgCO_2e$ per barrel of diesel. Using DOE/NETL, the well-to-wheels emission for 2005 US diesel is 524 $kgCO_2e$ per barrel of diesel.

**Table A-7**

**Well-to-wheel Emissions for the Average Barrel Consumed in the United States**

($kgCO_2e$ per barrel refined products)

| | Crude Production | Crude Transport | Crude Refining | Distribution | Fuel Combustion | Well-to-retail pump | Well-to-wheels |
|---|---|---|---|---|---|---|---|
| Average US Barrel Consumed (2005) | 39 | 7 | 55 | 2.1 | 384 | 103.1 | 487.1 |

Source: IHS CERA.

## SUMMARY OF WELL-TO-WHEELS GHG EMISSIONS FOR OIL SANDS AND CONVENTIONAL CRUDES

Table A-8 shows the values presented in Figures 3 and 4 of this study.

## Table A-8

### Well-to-wheels Greenhouse Gas Emissions for Oil Sands and Conventional Crude Oils (data from Figures 3 and 4)

($kgCO_2e$ per barrel refined products)

| | Crude Production | Crude Upgrading | Crude Transport | Crude Refining | Distribution of Refined Products | Fuel Combustion | Well-to-retail pump | Well-to-wheels | Percent Difference from "Average US Crude Consumed" |
|---|---|---|---|---|---|---|---|---|---|
| CSS Bitumen*** | 83 | 0 | 5.5 | 85 | 2.1 | 384 | 175.6 | 559.6 | 15% |
| Middle East Heavy Oil** | 98 | 0 | 9.1 | 60 | 2.1 | 384 | 169.2 | 553.2 | 14% |
| Canadian Oil Sands: SAGD SCO | 69 | 47 | 5.5 | 47 | 2.1 | 384 | 170.6 | 554.6 | 14% |
| California Heavy Oil | 85 | 0 | 5.5 | 73 | 2.1 | 384 | 165.6 | 549.6 | 13% |
| Venezuelan Partial Upgrader | 103 | 0 | 5.5 | 47 | 2.1 | 384 | 157.6 | 541.6 | 11% |
| Canadian Oil Sands: SAGD Bitumen | 69 | 0 | 5.5 | 85 | 2.1 | 384 | 161.6 | 545.6 | 12% |
| Nigeria Light Crude | 82 | 0 | 9.1 | 42 | 2.1 | 384 | 135.2 | 519.2 | 7% |
| Canadian Oil Sands: Mining SCO | 33 | 47 | 5.5 | 47 | 2.1 | 384 | 134.6 | 518.6 | 6% |
| Average Oil Sands Imported to United States (2009)* | 45 | 21 | 5.5 | 60 | 2.1 | 384 | 133.5 | 517.5 | 6% |
| Canadian Oil Sands: SAGD Dilbit | 50 | 0 | 5.5 | 70 | 2.1 | 384 | 127.6 | 511.6 | 5% |
| Canadian Oil Sands: Mining Bitumen | 33 | 0 | 5.5 | 85 | 2.1 | 384 | 125.6 | 509.6 | 5% |
| Venezuela - Bachaquero | 41 | 0 | 5.5 | 73 | 2.1 | 384 | 121.6 | 505.6 | 4% |
| Canadian Oil Sands: Mining Dilbit | 26 | 0 | 5.5 | 70 | 2.1 | 384 | 103.6 | 487.6 | 0% |
| Average US Barrel Consumed (2005) | 39 | 0 | 7 | 55 | 2.1 | 384 | 103.1 | 487.1 | 0% |
| Mexico - Maya | 32 | 0 | 5.5 | 60 | 2.1 | 384 | 99.6 | 483.6 | -1% |
| Average US Domestic Crude (2005) | 24.5 | 0 | 5.5 | 52 | 2.1 | 384 | 84.1 | 468.1 | -4% |
| Saudi Medium (ave) | 13 | 0 | 9.1 | 56 | 2.1 | 384 | 80.2 | 464.2 | -5% |
| Canadian Heavy (Bow River) | 15 | 0 | 5.5 | 60 | 2.1 | 384 | 82.6 | 466.6 | -4% |
| West Texas Intermediate | 5 | 0 | 5.5 | 42 | 2.1 | 384 | 54.6 | 438.6 | -10% |

Source: IHS CERA.
Notes: *Assumes 55 percent of exports to the United States are dilbit blends and 45 percent are SCO (source: NEB 2009 oil sands exports). This is a best estimate and not a precise number as there are many types of blends and qualities of SCO that are exported.
**Steam injection is used for production.
***Assumes SOR of 3.35.
12 percent loss of volume upgrading bitumen to SCO.
All SAGD crude production cases assume an SOR of 3.
All oil sands cases marked “dilbit”, assume that the diluent is consumed in the refinery, with no recycle of diluents back to Alberta, and only 70 percent of the barrel is from oil sands.
All oil sands cases marked “Bitumen” assume that the diluent is recycled back to Alberta, and all of the barrel processed at the refinery is from oil sands.

# Oil Sands Technology

Past, Present, and Future

SPECIAL REPORT™

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For clients with access to **IHSCERA.com,** the following features related to this report may be available online: downloadable data (excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

## About This Report

**Purpose.** Since the inception of the first commercial oil sands facilities, the industry has established a track record of ongoing technical innovation—reducing costs, increasing recovery, increasing efficiency, and reducing its environmental intensity. This report identifies and quantifies these past innovations, while analyzing the potential and challenges in achieving further gains. The oil sands industry is increasingly under pressure—from the public, the government, regulators, and its only export market, the United States—to further reduce its environmental impact. Ability to demonstrate improvements will be a critical factor shaping the economic and political playing fields for Canadian oil sands.

**Context.** This is the third in 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. The 2010 Dialogue program and associated reports cover four oil sands topics:

- the role of Canadian oil sands in US oil supply
- oil sands, greenhouse gases (GHG), and US oil supply: getting the numbers right
- oil sands technology: past, present, and future
- oil sands and GHG policies

These reports and IHS CERA's 2009 Multiclient Study *Growth in the Canadian Oil Sands? Finding the New Balance* can be downloaded at www2.cera.com\oilsandsdialogue.

**Methodology.** This report includes multistakeholder input from a focus group meeting held in Calgary on August 10, 2010, 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 this report for a list of participants and the IHS CERA team).

**Structure.** This report has five major sections, including the Summary of Key Insights:

- Summary of Key Insights of IHS CERA's Analysis
- **Part I: The Evolution of the Oil Sands Industry.** What factors have shaped the history of innovation? What are the technologies for extracting oil sands today?
- **Part II: Benchmarking Environmental Change, Past to Present.** How have GHG emissions and water consumption per barrel produced changed over time? What technologies have shaped these improvements?
- **Part III: Future Technology Drivers for Oil Sands.** How could technology further reduce environmental intensities—and what are the challenges to realizing these benefits? What are the emerging technologies?
- **Part IV: Where Is the Industry Headed?** In aggregate what level of environmental improvement is ultimately possible? How is future research and development being supported?

# OIL SANDS TECHNOLOGY: PAST, PRESENT, AND FUTURE

## SUMMARY OF KEY INSIGHTS OF IHS CERA'S ANALYSIS

**A track record of ongoing, continuous technical improvement has enabled oil sands growth. At the same time, innovation has improved the environmental performance of production, lowering the average amount of greenhouse gases (GHGs) emitted per barrel of output.** Since 1990 the intensity of GHG emissions per barrel of output for mining and upgrading operations has fallen by 37 percent on a well-to-retail pump basis. Since the inception of steam-assisted gravity drainage (SAGD) a decade ago, well-to-retail pump emissions have declined 8 percent per barrel. Mining and SAGD account for close to 70 percent of total oil sands supply. For cyclic steam stimulation (CSS)—which produces 16 percent of oil sands output—GHG intensity has increased.

**The trend of declining GHG emissions intensity is expected to continue, but the absolute level of GHG emissions will grow as oil sands production volumes increase.** A scenario with rapid technical innovation and relatively moderate oil sands growth—3.1 million barrels per day (mbd) by 2030 from 1.35 mbd in 2009—would reduce the GHG emissions per barrel of production by over 30 percent, but total GHG emissions from oil sands upgrading and production would still grow, from 5 percent of Canada's emissions to about 10 percent. However, in the absence of new oil sands supply, global oil demand is still projected to grow, and substituting oil sands supply for another source still results in emissions growth.

**Deployment of new technology and methods has reduced the water use intensity of production, particularly the use of fresh water.** The original SAGD operations required over 1 barrel of fresh water per barrel of bitumen produced. Today, on average, SAGD operations consume 0.7 barrels of water per barrel of bitumen produced, with 60 percent from nonpotable brackish water sources. For CSS water use has decreased from over 3 barrels of fresh water per bitumen barrel produced to less than 0.6 barrels. For mining operations the water consumed per barrel of bitumen extracted has not declined substantially, but because of improved water management practices the amount of water withdrawn from the Athabasca River has been reduced, from 3.5 barrels of water per barrel produced a decade ago to 2.5 barrels currently.

**The oil sands industry is continually evolving; past innovations have centered on improving the economics of recovery. Over the coming decades new technologies must meet both economic and environmental goals. Improvement on both fronts is expected, but the pace and ultimate size of future gains is uncertain.** For SAGD developments ongoing efficiency improvements and new hybrid steam-solvent technologies could reduce well-to-retail pump emissions by 5 to 20 percent per barrel produced, and water consumption could potentially decline by 10 to 40 percent per barrel. For the more mature mining operations GHG emissions gains are projected to be smaller. GHG intensity could decline

5 percent (well-to-retail pump), plus there are prospects for decreasing water consumption. However, new technologies must overcome economic and environmental hurdles; if not, widespread adoption is unlikely. A second factor is reservoir quality. 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. The next phase of oil sands projects involves lower quality resources. Without new techniques, some of the new sites could require more energy compared to today's developments.

**Past oil sands innovation has most often been the product of collaboration and partnership between industry and government. This trend is growing and is preferable to operating in research silos.** There is a growing appreciation that collaboration among industry players and government is beneficial—both to the speed of innovation and to the potential benefits of new technology in diminishing environmental impacts. Numerous initiatives are developing new technology through cooperative funding and research. The industry itself is cooperating more through various oil sands groups; a recent example includes the sharing of new environmental technologies with competitors without fees or royalties.

**Beyond the next two decades, new methods of extracting oil sands are likely to lead to more reductions in GHG intensity and environmental impacts, but these trends are not inevitable. More research and development is needed.** Ideas for new methods to extract bitumen include electric heating, solvents, in-situ combustion, and underground tunnels. These methods have the potential to decrease the environmental footprint of production while unlocking new parts of the oil sands deposit—oil that is currently not recoverable. Because of the time lag between a successful pilot and broad commercial deployment, the potential benefits from these revolutionary technologies are probably 15 to 20 years away.

**Carbon capture and storage (CCS) efforts are enhanced by government engagement, but it is a high-cost activity.** Given the Alberta and Canadian government's significant investment in CCS, it is probable that at least one project will be operating in the oil sands. It will be installed at the lowest cost point of capture—the concentrated carbon dioxide ($CO_2$) sources found at the upgraders in proximity to geologic storage (central Alberta). Capturing these emissions reduces the GHG intensity of oil sands production by 11 to 14 percent (well-to-retail pump). CCS for upstream facilities will take much longer to develop (if it happens at all). Here the $CO_2$ comes from dilute combustion streams, and capturing these emissions is both expensive and energy intensive; and added to this is the fragmented nature of the upstream extraction facilities and the lack of geological carbon storage in the Fort McMurray region.

—January 2011

# OIL SANDS TECHNOLOGY: PAST, PRESENT, AND FUTURE

Technical innovation is at the heart of the Canadian oil sands story. "Cracking the code" of more efficient production has enabled the oil sands to become one of the most important sources of global supply growth, while also strengthening North American energy security. The oil sands will soon become the largest source of US oil imports. Innovation has focused on increasing the economic viability of oil sands in the global market, but it has also led to an improved environmental performance. Further challenges face the industry, especially since concerns about climate change have intensified the worldwide debate about oil resource development.

Innovation remains the key to helping oil sands meet environmental and economic objectives. This report discusses new and evolving technologies that have the potential to further reduce the environment impact of oil sands activity, including shrinking greenhouse gas (GHG) intensity of the production process and reducing water use intensity. Ongoing improvements in oil sands extraction and upgrading are expected but not guaranteed, given the countervailing challenges of decreasing reservoir quality and the need for new technologies that are both environmentally sustainable and economic.

This report has four main parts:

- The first part focuses on understanding the historical context of innovation and technological development. This provides a framework on how the industry got started and how it has evolved to its present state of operation and production.
- The second section benchmarks environmental changes from the past to current.
- The third part focuses on how the application of new technologies could reduce water consumption and GHG emissions intensity. We explore a wave of innovation at work and a wide diversity of paths of innovation at various stages of development.
- The final section assesses what the past, present, and future of innovation mean for the oil sands and identifies what is potentially achievable in reducing environmental impacts in the aggregate.

# PART I: THE EVOLUTION OF THE OIL SANDS INDUSTRY

## A BRIEF HISTORY OF OIL SANDS DEVELOPMENT

The century following the 1884 mapping of the Canadian oil sands deposit was marked by great potential held in check by technological challenges. For much of this time oil sands were simply was too expensive to process and ship to market. But over the past several decades pivotal advances were made that enabled the oil sands to become one of the top sources of global oil supply growth. Production more than doubled, from 0.6 mbd in 2000 to 1.35 mbd in 2009. By 2020 oil sands output is likely to double again and could be higher than the national production from several OPEC member states.

The “oil” in the oil sands comes from bitumen, which is extra-heavy oil with high viscosity. In others words it has the feel of what some might call a sticky hockey puck. The thick, heavy oil does not flow at reservoir temperatures, making attempts to produce it using conventional methods futile. It was 1925 before the first major innovation was made in producing the oil sands. In that year Dr. Karl Clark of the Alberta Research Council demonstrated the first separation of oil from the sands using hot water and caustic soda. The process was patented in 1928 and still forms the basis of oil sands mining extraction.

At the same time a Nova Scotia entrepreneur began construction of a plant at the Bitumount, Alberta, site. Here oil sands were surface mined, and the bitumen was extracted using the hot water process. After a checkered history of experimentation, including numerous bankruptcies and one government bailout, the plant was officially closed in 1958. Meanwhile a separate company, Abasand Oils, built a processing plant in 1935 to produce diesel. After a decade of tribulations in processing oil sands—including numerous fires—this plant was also closed down.

As in any process of innovation the road to commercial development is often rocky and full of setbacks and pitfalls. Getting to commercial development in oil sands has been no exception.

### Surface Mining: Commercial Production Gains a Foothold

A key step in commercialization took place in 1953 with the formation of the Great Canadian Oil Sands (GCOS), a consortium led by Sun Oil, a predecessor of today’s Suncor Energy. After a vast investment of over C$1.6 billion in today’s dollars, the first lasting mining and upgrading operation came into production in 1967.* The GCOS plant had to overcome many operational problems, unsurprising given this was the first attempt at commercial oil sands production. Numerous problems were encountered in scale-up. The hot water extraction process struggled with the variability in ore grades, the massive bucket-wheel excavators had productivity issues, and the conveyors regularly needed repair. However, this first plant proved an invaluable learning experience for the mining oil sands business. Continuous

*The original investment of C$250 million was estimated in today’s dollars. At the time, this was the largest private investment ever made in Canada (source: Suncor website).

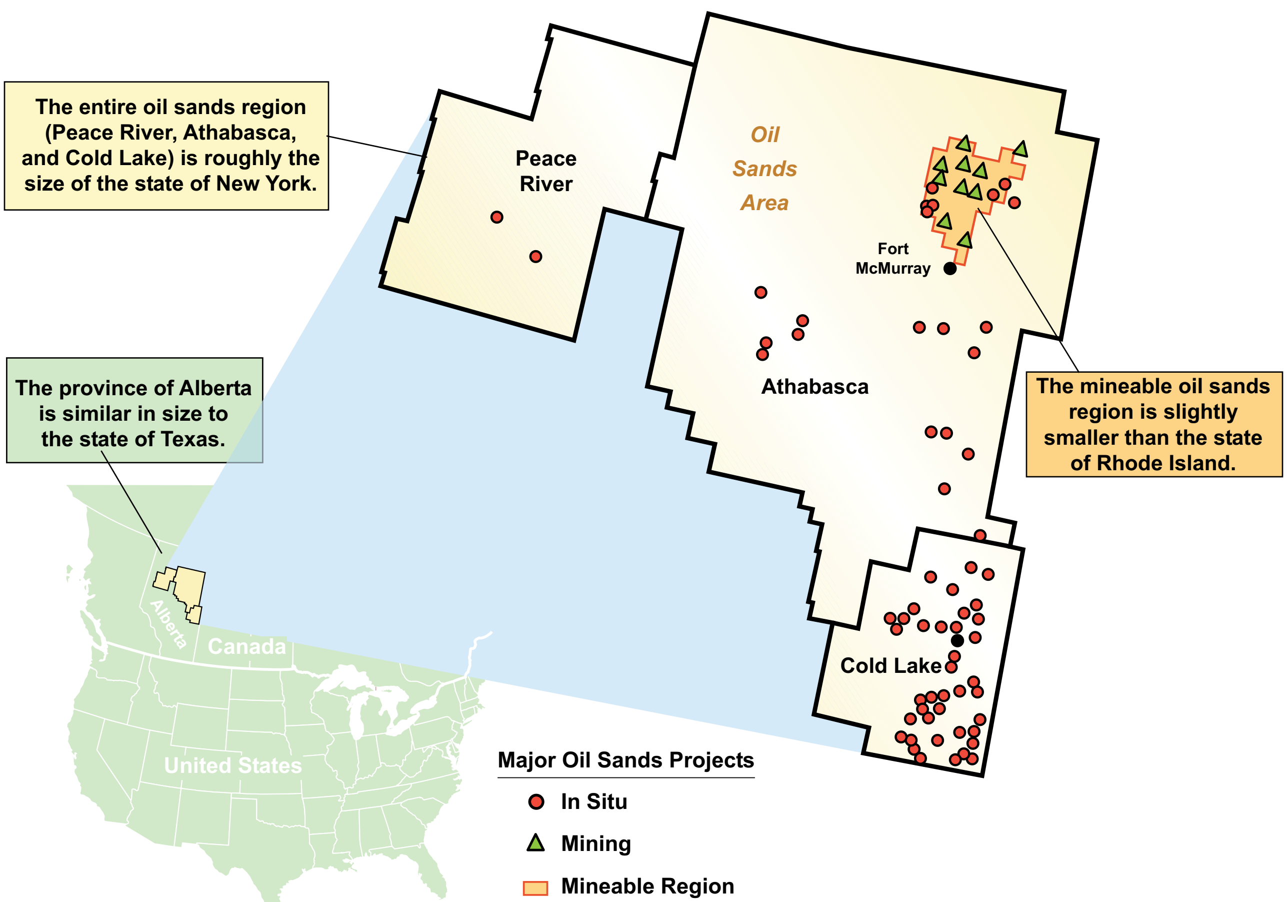
innovation over an extended period has borne fruit in the productivity and economics of today's mining operations.

But confidence in the operation of the GCOS plant was growing. The next major step was the development of the Syncrude operation. Syncrude's new oil sands surface mine and upgrader opened in 1978 amid rising oil prices and growing energy security concerns.

Although extracting oil sands from surface mining was gaining considerable momentum, new methods were required to access the much larger nonminable part of the oil sands—deposits buried too deep to surface mine. The oil sands deposit is concentrated in three major areas: the Peace River, Cold Lake, and Athabasca deposits. By far the largest deposit is the Athabasca, with over 80 percent of the oil in place. Within the Athabasca deposit a small area (less than 3 percent of the total oil sands area) is close enough to the surface for mining (see Figure 1).

**Figure 1**

**Location of Canadian Oil Sands Resources**




Source: IHS CERA.
Note: Comparisons to US states are to the total areas of the states, including land and water.
60713-19

## Going Underground: In-situ Production

Imperial Oil made the first steps in producing bitumen from the deeper deposits by patenting the CSS process in 1966. After 20 years of improving the process commercial production was achieved in 1985. Although Imperial's cyclic steam stimulation (CSS) method was successful, it is a high-pressure process best suited for operations in the relatively small Cold Lake and Peace River oil sands deposits.* New lower-pressure techniques were required to produce bitumen from the much larger, shallow Athabasca deposit. The government's support and participation played a key role in finding the solution for unlocking bitumen from the massive Athabasca deposit. In 1974 the Alberta government, under the leadership of Peter Lougheed, was instrumental in the creation of the Alberta Oil Sands Technology and Research Authority (AOSTRA). AOSTRA became the crucible of oil sands research, especially for the vast tract of oil sands resources too deep for surface mining.

Imperial Oil was the first to pilot the SAGD recovery process at Cold Lake in the late 1970s, patenting the technique in 1982. Later, Roger Butler from the University of Calgary (formerly an employee of Imperial) proposed to AOSTRA to pilot the SAGD concept in the more shallow Athabasca deposit, which resulted in the 1984 Underground Test Facility pilot. Initially the Alberta government funded the project alone, but eventually the industry partnered in the investment. It took a further 15 years for true commercial development, but a major innovation that could extract bitumen at low pressures and access a larger part of the deep oil sands deposit was born.

Over its 25 years in existence AOSTRA through the Alberta government partnered with industry on 16 field trials. In addition to promoting the eventual commercialization of the SAGD process, the AOSTRA field trials provided a wealth of data and lessons on alternative production techniques. In the first 15 years of AOSTRA the Alberta government and industry jointly invested over C$2 billion (current dollars) in research and development (R&D).** Although AOSTRA was dissolved in 1995, the Alberta government remains actively engaged in oil sands R&D through current initiatives such as Alberta Innovates—Energy and Environmental Solutions (formerly AERI) and the Climate Change and Emissions Management Corporation (CCEMC) (see Part IV for more details on research).

These first oil sands developments—the "learning projects"—involved large, high-risk investments and formed the foundation of the advances in extraction processes that dominate the industry today. Without risking significant sums of up-front capital—often shared by government, industry, and the capital markets—it is unlikely that production from oil sands would be where it is today.

*In the smaller Peace River and Cold Lake deposits the reservoir is deep, allowing bitumen to be extracted at higher pressures. Additionally the smaller deposits are generally not in contact with thief zones—water or gas zones that steal heat—characteristics that are common in the Athabasca deposit.
**Source, AOSTRA, *A 15 Year Portfolio of Achievement.* Original spend was C$1 billion.

## OIL SANDS TODAY

The Alberta oil sands are an immense resource. Current estimates of economically recoverable oil are 170 billion barrels—the second largest in the world after Saudi Arabia.* Today four commercial technologies are used to produce oil sands (see Table 1).

### Cold Flow and Enhanced Recovery

Some areas of the oil sands resource, comprising slightly less viscous oil, are amenable to "cold flow" methods. The "nonsteam" production methods include cold heavy oil production with sand (CHOPS) and production from horizontal wells; enhanced recovery methods such as water or polymer flooding are also used.** In 2009 cold flow production constituted 15 percent of oil sands production; it is projected to decline to less than 5 percent of production by 2030.

### Mining

About 20 percent of currently recoverable oil sands reserves lie close enough to the surface to allow open-pit mining (see Figure 2). The bitumen is produced using a strip mining process similar to that for coal mining. The overburden (primarily soil and vegetation) is removed, and a layer of oil sands is excavated using massive shovels and moved by pipeline or truck to a processing facility where the bitumen is extracted using the hot water technique. Today all sites are integrated mine/extraction-upgrading operations; these operations extract the heavy bitumen and upgrade it to a light crude oil called synthetic crude oil (SCO).*** The first mining/extraction-only operation (Imperial's Kearl Mine) is now under construction. This project will not upgrade its product; rather the extracted bitumen will be shipped as a diluted bitumen blend (dilbit) by pipeline to refineries in Canada or the United States for upgrading to petroleum products.

**Table 1**

**Breakdown of Oil Sands 2009 Production by Extraction Method**

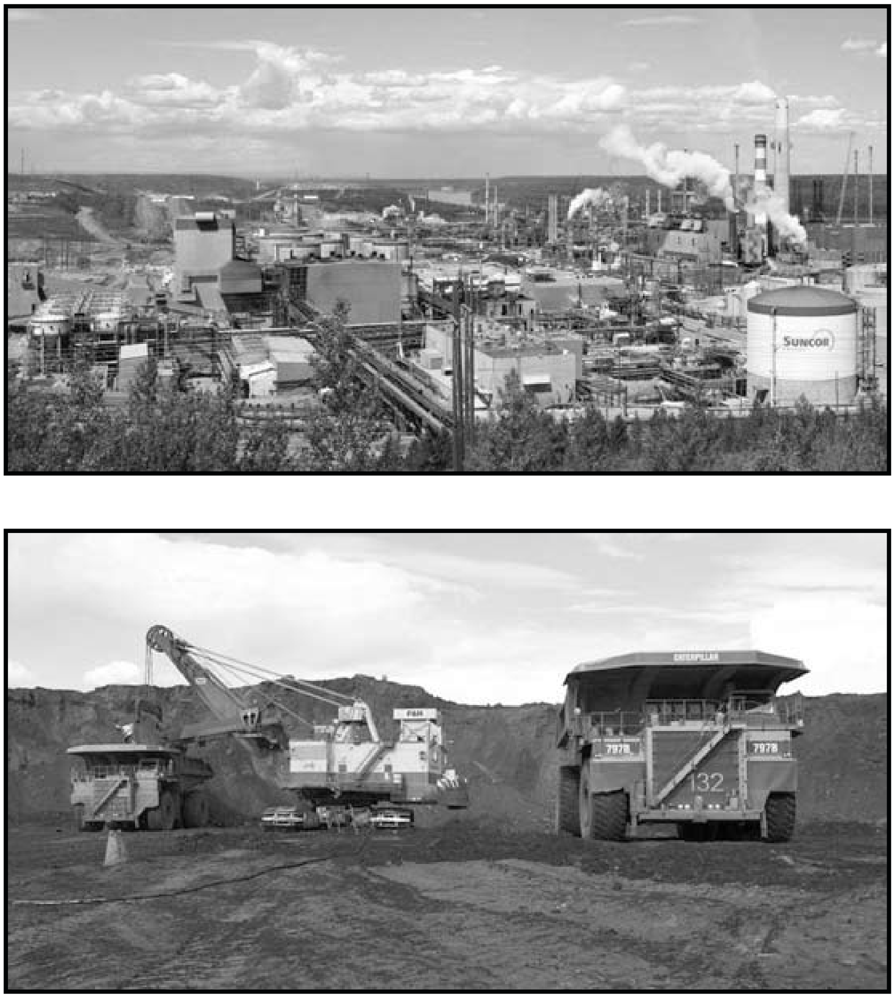
| | 2009 Production (bd)[1] | Percent of Oil Sands Production |
|---|---|---|
| Cold flow and enhanced recovery | 206,941 | 15 percent |
| Mining | 690,154 | 51 percent |
| In-situ—CSS | 213,860 | 16 percent |
| In-situ—SAGD | 242,794 | 18 percent |

Source: ERCB Alberta's Energy Reserves and Supply Outlook, June 2009.
1.Barrels per day.

*Alberta Energy Reserves 2009 and Supply/Demand Outlook 2010-2019, Alberta Energy Resources Conservation Board (ERCB).
**In producing bitumen using the CHOPS method, both sand and oil are recovered using progressive cavity pumps. Significant volumes of sand are produced and sand disposal is required. To produce bitumen using enhanced recovery methods such as water and polymer flooding, water or polymer is injected into the reservoir to displace the bitumen into the production wellbores.
***An oil sands upgrader is akin to a refinery, converting the heavy bitumen to a lighter crude oil product.

**Figure 2**

**Mining Extraction and Upgrading Facility**




Source: Suncor Energy.
01212-4

Although the minable part of the oil sands is just 20 percent of the total resource, it is still large—34 billion barrels of bitumen recoverable. Production from mining operations is expected to keep growing, and thus mining is likely to maintain its position at nearly half of the oil sands production for the next 20 years.

## In-situ Thermal Processes

About 80 percent of the recoverable oil sands deposits are too deep for surface mining and are recovered using drilling techniques combined with thermal transfer. In-situ thermal methods inject steam into the wellbore to lower the viscosity of the bitumen, allowing it to flow and be pumped to the surface. Two thermal processes are in commercial use today: CSS and SAGD.

## CSS

CSS, also called huff and puff, is a three-stage steam injection process that uses vertical, deviated, and horizontal wells. This was the first process used to commercially recover oil sands in situ (see Figure 3). CSS production volumes are projected to decline from 16 percent currently to less than 10 percent of oil sands by 2030, as SAGD production from the larger Athabasca oil sands deposit continues to grow.

## SAGD

SAGD is the technique advanced by AOSTRA in the early 1980s. In this process two parallel horizontal wells—vertically separated by about 5 meters—are drilled in the oil sands formation. The upper well is used for steam injection, which heats the reservoir and bitumen, allowing it to flow into the lower well (see Figure 4). Production from SAGD currently makes up 18 percent of production and is projected to increase to more than 40 percent of total production by 2030.

**Figure 3**

**CSS Well Pad and Central Facility**

Source: Imperial Oil Resources—Cold Lake.
01212-6

**Figure 4**

**SAGD Well Pad and Central Facility**

Source: Cenovus Energy—Foster Creek.
01212-5

# PART II: BENCHMARKING ENVIRONMENTAL CHANGES, PAST TO PRESENT

Historical analysis indicates that deployment of new technologies often follows an S-shaped curve. Initial progress is often slow, but when the technology "crosses the chasm," learning reaches a critical stage and takeoff is rapid. The stage of rapid commercialization results in gains in efficiency and productivity, lower materials use, and lower energy use. This section of the report measures improvements in the overall efficiency of converting the oil sands resource into a barrel of bitumen or SCO over time. We first discuss the history of changes in mining and upgrading and then turn to SAGD, the second most-used method of oil sands extraction. We end this section by reviewing the third major method of oil sands production, CSS.

## MINING AND UPGRADING

Established over 40 years ago, the main method of oil sands production, mining, and upgrading has improved its environmental performance per barrel produced.

### Energy Consumption and GHG Emissions

Over the past two decades mining operators have learned how to produce bitumen more efficiently, reducing GHG emissions per barrel by 37 percent on a well-to-retail pump basis (see Figure 5).* Major drivers of reduced GHG emissions include the following:

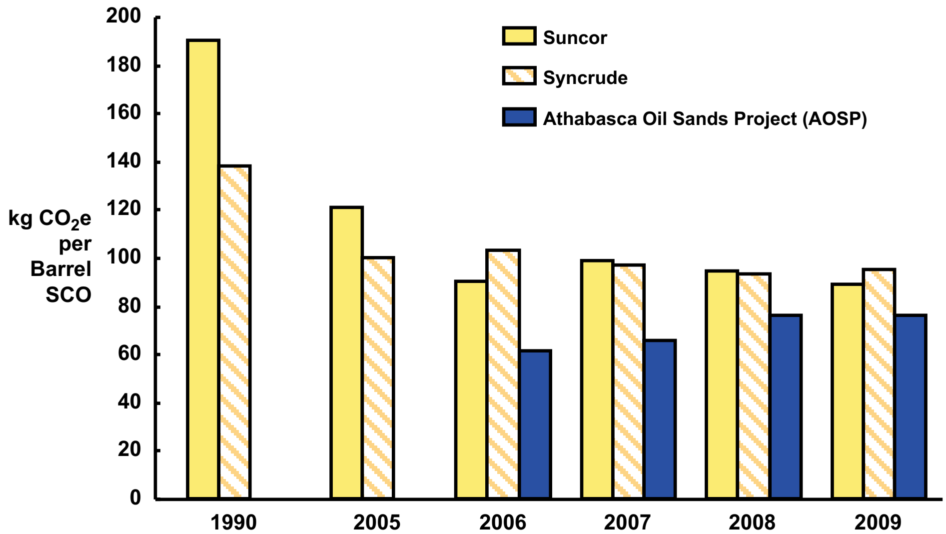
- **Hydrotransport and improvements in bitumen extraction.** More than half of the energy savings in mining operations has resulted from improvements in extracting the bitumen from the sands. The initial Clark hot water process required temperatures of 80 degrees Celsius (°C), and today ranges between 40 and 50°C. The chief enabler of the reduced temperature was the discovery of hydrotransport, a method of fluidizing the bitumen-laden ore and transporting it by pipeline to the extraction vessel, as opposed to moving it by conveyer belt. By using a pipeline the bitumen-sand slurry is mixed while transported, and the bonds between the bitumen and the sand start to break down before entering the extraction process. As a result lower temperatures are needed to extract the bitumen. Other significant extraction energy reductions have come from improved heat integration (recovering more waste heat from the extraction waste stream) and increasing the recoveries of bitumen.

- **Shifting to natural gas cogeneration for electricity and steam.** The first oil sands operations generated electricity primarily from fuels produced on site. For example Suncor's original plant used some petroleum coke for generating both electricity and steam. Syncrude generated energy from upgrader off-gas. Over time both operations have shifted to supplying increasing portions of electricity and steam from lower–carbon emitting natural gas cogeneration.

*The production-weighted average GHG intensity was calculated across all projects at each period (Suncor, Syncrude, and Athabasca Oil Sands Project [AOSP]).

**Figure 5**

**Mining and Upgrading Oil Sands: GHG Emissions per Barrel of SCO**




Sources: Syncrude 09/10 Sustainability report, Suncor Energy Sustainability reports and company data, AOSP—Muskeg River Mine and Scotford Upgrader Shell Sustainability Report 2009. (Note: AOSP is a joint venture project operated by Shell; partners are Shell Canada, Marathon Oil Canada, and Chevron Canada.)
01212-1

- **Upgrading efficiency improvements**. Over time upgraders have been optimized and energy consumption has been reduced. Improvements have stemmed from numerous initiatives, some of the largest gains have resulted from improved heat integration (recovering more heat from process streams).

- **Improvements in new operations.** The most recent oil sands mining projects have the advantage of "starting from scratch" and taking advantage of the latest techniques and equipment (new projects are Horizon plant of Canadian Natural Resources Limited (CNRL) and the AOSP).* These new operations have implemented ideas learned from the original operations plus new energy-saving techniques. Because the new plants are more efficient, the GHG emissions are 15 to 25 percent lower than those from the original operations.** Phase 1 of AOSP, which started operations five years ago, deployed a number of energy-saving ideas. One improvement was in extracting the heaviest component of the bitumen—asphaltenes—before upgrading. By removing the highest-carbon component of the bitumen barrel, the emissions from upgrading are lowered. Most operations send hot water from the extraction process to tailings ponds

*AOSP is a joint venture operated by Shell; partners are Shell Canada (60 percent), Marathon Oil Canada (20 percent), and Chevron Canada (20 percent).
**Source: AOSP Muskeg River Mine and Scotford Upgrader, Shell Sustainability Report 2009; emissions are about 25 percent lower than established operations. CNRL 2010 Horizon report to stakeholders, emissions projected to be 15 percent lower than comparable operations.

to cool, but the AOSP project is more efficient and recycles a small portion of the hot water back immediately, thereby reusing some of the heat.

### Water Consumption

Approximately 12 to 14 barrels of water are used to extract a barrel of bitumen from mined oil sand ore, and about 70 percent of this water can be recycled. The remaining water, about four barrels, is trapped in the mining waste—a mixture of water and fine clay and silt about the consistency of yogurt. As water does not separate naturally from this material, the mining waste is stored in tailing ponds. To account for the water lost to the tailings, additional water is required. Part of this water comes from the Athabasca River, and part is collected from site runoff and mine dewatering. For integrated oil sands mining and upgrading facilities the water supplied from the Athabasca River ranges from 2 to 2.5 barrels of water per barrel of SCO produced; this is about 1 barrel less than ten years ago.

## SAGD PRODUCTION

Established just over a decade ago, the second largest and fastest growing method of oil sands production is SAGD. Today's SAGD production has reduced its environmental intensity compared with the original operations.

### Energy Consumption and GHG Emissions

Just over a decade ago the first in-situ SAGD development—Foster Creek—started operation. Four other first generation projects followed, commencing operations in the early 2000s.*

The steam-oil ratio (SOR) is a critical measure of the efficiency of thermal in-situ production. It measures the average volume of steam—generally produced using natural gas as a fuel—needed to produce one barrel of bitumen. There are two ways to measure SOR:

- **Cumulative steam-oil ratio (CSOR).** This method measures the average volume of steam—over the entire life of the operation—required to produce one barrel of bitumen. A CSOR of 3.2 means that since the start of operations, on average 3.2 barrels of steam were required to produce one barrel of bitumen.

- **Instantaneous steam-oil ratio (ISOR).** This measures the current or instantaneous rate of steam required to produce a barrel of bitumen. For example an average ISOR of 3.0 means that currently the operation needs three barrels of water to be vaporized to steam to produce one barrel of bitumen. The ISOR is lower than the CSOR because the ISOR does not account for the steam injected to warm the reservoir prior to first production.

Comparing the CSOR from the first years of the projects to the current values shows a steady decline in steam (and hence energy) use per barrel of bitumen produced. Today the average CSOR across the first generation projects has dropped 0.6—from 3.4 in the early

*First generation commercial projects include today's Cenovus/Conoco Phillips Foster Creek (1997), JACOS Hangingstone (1999), Cenovus/ConocoPhillips Christina Lake (2002), Suncor Energy MacKay River (2002), and Suncor Energy Firebag (2004).

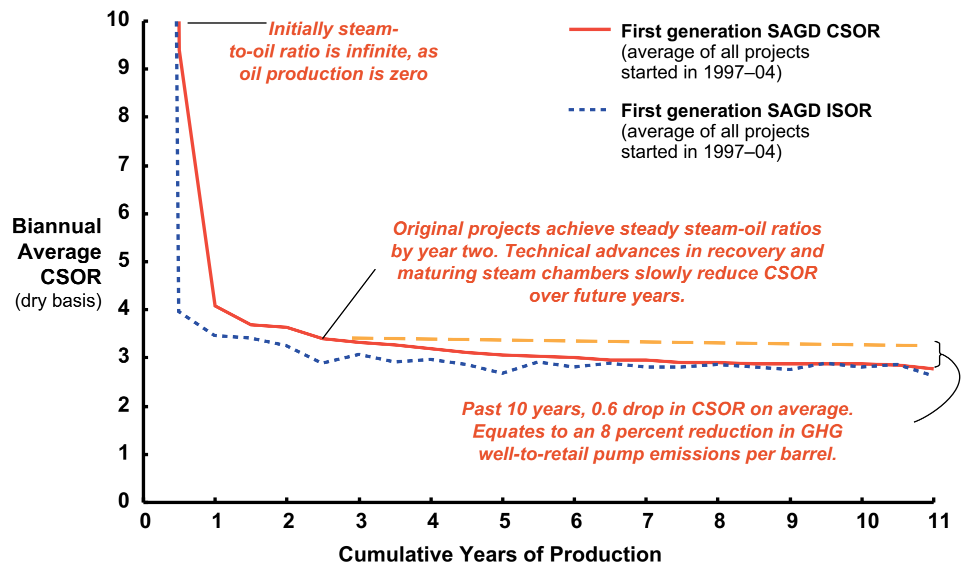
years of each project to 2.8 today. This equates to about an 18 percent reduction in GHG emissions for producing a barrel of bitumen with SAGD over the past decade, or equivalent to an 8 percent reduction on a well-to-retail pump basis (see Figure 6).*

For SAGD production it is still relatively early days, and longer-term SOR trends are somewhat uncertain; so far the historical trend is one of declining steam requirements per barrel of output. For an individual well pair, the SOR is expected to start out high and then decrease sharply over the first 18 months, followed by slighter declines as the steam chamber matures. Late in the life of a field, after most of the recoverable oil has been produced, the SOR increases. Production will stop when the steam rate becomes too high for economic production. A given oil sands operation has numerous well pairs, all at different stages of this life cycle.

Considering this life cycle, the measured 0.6 improvement to date in CSOR is partly from the advancing maturity of the steam chamber (SOR declines slightly as the steam chamber matures) and partly from technical advancements in SAGD production. Since the start-up

**Figure 6**

**First Generation SAGD Projects: Progression of Steam-to-oil Ratios**




Source: IHS CERA.
Notes: First generation projects included in average are Cenovus/ConocoPhillips Foster Creek (1997), Cenovus/ConocoPhillips Christina Lake (2002), Suncor Energy MacKay River (2002), Suncor Energy Firebag (2004), JACOS Hangingstone (1999). The production-weighted average CSOR was calculated across all first generation projects. The average CSOR between year two and three was compared to the average CSOR in the past six months. Data source ERCB, IHS.
01212-2

*The production weighted average CSOR was calculated across all first generation projects. The average CSOR between year two and three for each was compared with the average CSOR in the past six months. The GHG savings do not account for GHG reductions from electricity cogeneration.

of the first generation projects less than a decade ago, three major energy-saving technical innovations have been applied in SAGD operations:

- **Improved reservoir characterization and wellbore placement.** The level of understanding of the behavior of the SAGD reservoir has increased sharply since the first operations. Most likely this has been the largest contributor to reduced energy in SAGD production. Operators are now able to visualize the reservoir using data from observation wells and advanced seismic data. New drilling technologies and techniques allow operators to accurately place the wells in optimal locations.

- **Electric submersible pumps (ESPs).** The original SAGD operations used a gas-lift technique to lift fluids to surface. The operator would have to operate SAGD at high reservoir pressures for gas-lift to perform effectively. This resulted in nonoptimal SOR and costly heat loss to nonbitumen zones. With ESPs capable of handling high temperatures, the operators are able to reduce the SAGD operating pressure, which reduces steam losses, energy usage, and the overall SOR.

- **Wellbore liner improvements.** Oil sands bitumen is found in deposits of unconsolidated sands. Loose sands create difficulties for bitumen production. Sand tends to enter and plug the well liner, leading to operational problems in downstream facilities and nonoptimum use of steam. Operators are learning the most optimal configurations of liners for each well, resulting in both increased operational time and reduced energy losses from uneven steam distribution.

Taking into account these improved practices, how have the second generation SAGD projects—projects that have commenced production after 2006—fared in energy efficiency?*

The average CSOR for the group of second generation SAGD projects is 4—higher than the first generation projects (see Table 2). The higher SORs stem from numerous factors: operational challenges in start-up, more difficult reservoirs, projects that are still ramping up to nameplate capacity, and learning by first-time operators. It is important to note that the majority of second generation projects have not required significantly more energy compared with their first generation counterparts; the average CSOR for the top four projects (representing over 70 percent of second generation production) is 3.1.

A significant factor dictating the absolute SOR level for an operation is reservoir quality. Generally, the first generation SAGD projects had high quality reservoirs: thick continuous pay zones, high porosity, and high oil saturations. These qualities allow for more energy efficient production.

The higher CSOR on some of the second generation sites highlights a risk in maintaining the ongoing track record of efficiency when moving to different oil sands leases or areas of the same lease that are lower quality. However, even operations with elevated SORs, without the lessons from the first generation projects' higher SORs likely would have resulted. The

*Second generation projects include Husky Energy Tucker (2006), ConocoPhillips/Total Surmont (2007), MEG Energy Christina Lake (2009), Connacher Oil & Gas Great Divide (2007), Nexen Long Lake (2007), Devon Canada Jackfish (2007), and Shell Orion (2007).

**Table 2**

**SAGD Project Level CSOR and ISORs (January to June 2010)**

| Project | Project Generation | ISOR | CSOR | Average Daily Production |
|---|---|---|---|---|
| First generation average (production weighted) | First | 2.61 | 2.78 | 211,218 |
| Second generation average (production weighted) | Second | 3.71 | 4.03 | 101,136 |
| All projects average (production weighted) | All projects | 2.97 | 3.19 | 312,354 |

Source: IHS CERA.

majority of second generation projects are also still relatively early in their life cycle, and SORs are projected to decline further as the operations continue to mature.

## Water Consumption

Today groundwater is the primary water source for SAGD oil sands production. The amount of fresh water used for SAGD production has been decreasing over time. A decade ago operations used only fresh water, consuming more than one barrel of water per barrel of bitumen produced.* Currently the use of nonpotable salty water from deep aquifers, known as brackish groundwater, has become common.

To understand current water demands, we surveyed ten SAGD sites representing 97 percent of total production.** On average the group of SAGD operations consumed 0.7 barrels of water per barrel of bitumen produced, with 60 percent of the water consumed from brackish sources. The operations were recycling 75 percent of the water they produce. Not all sites are average; some operations use only brackish water, while others use only fresh water because they have no on-site brackish water source.

The type of technology used for steam generation is an important factor in determining the recycle rate and consequently the volume of water consumed. The various technologies deployed are

- **Once-through steam generators (OTSG).** Currently OTSGs are the most common technology for steam raising. Before entering the steam generator, water is treated with water softening chemicals to prevent solids from fouling the boilers. In the OTSG about 75 to 80 percent of the feed water is vaporized. The remaining wastewater (having high silica, hardness, and solids) is injected into deep disposal wells or salt caverns. This wastewater, often called blowdown, has been the limiting factor in further reducing net water use. Using an OTSG for a typical SAGD project consumes about 0.9 barrels of blowdown water per barrel of bitumen produced.***

*Although in-situ production uses some surface water, most of the fresh water comes from deep wells. The groundwater termed "fresh water" is typically not drinkable because of its high solids content—well above the 500 parts per million limit for drinking water.
**Source 2009 ERCB operator progress reports and IHS.
***Assumes SOR of 3.

- **Evaporators with drum boilers.** An alternative steam generation method—which is becoming more common for new developments—is to combine evaporators with drum boilers. The benefit of evaporators compared to water softening chemicals is they remove solids and hardness before the water enters the boiler. With cleaner feed water, more energy-efficient drum boilers can be deployed (instead of OTSG). An evaporator–drum boiler on a typical SAGD project consumes 0.4 to 0.5 barrels of water per barrel of bitumen produced.*

- **Zero liquid discharge (ZLD).** A small number of sites go even further, completely eliminating the waste stream, crystallizing the waste solids and recycling the resulting water; usually such ZLD sites do not have the option of deep-well disposal on their lease and therefore choose this option. For these sites water consumption can be lower than 0.2 barrels of water per barrel of bitumen produced.**

## CSS PRODUCTION

Established 25 years ago, the third largest method of oil sands production, CSS, has benchmarked reductions in water intensity although GHG emissions per barrel have increased, mostly in the past decade.

### Energy Consumption and GHG Emissions

Analyzing the annual average CSOR for each year of CSS production from the mid-1980s shows a slight increase in the energy required to produce bitumen; today's average ratio is about 3.6 compared with ratios of around 3.2 in earlier years of commercial CSS production. For the first 15-plus years the annual average CSORs stayed relatively constant between 3.2 and 3.3. Over the past six years the CSOR has increased to 3.6. This change equates to a 12 percent increase in producing a barrel of bitumen with CSS, or a 6 percent increase on well-to-retail pump basis (see Figure 7). *** It is important to note that with CSS the steam is not the same quality as for SAGD—it is higher pressure and wet (containing both water and vapor). Therefore care must be taken when comparing absolute CSORs between the SAGD and CSS processes, as they are not necessarily equivalent on an energy input basis.

The CSS projects are more mature plays than SAGD, and over time the amount of energy required to produce a barrel of bitumen is increasing. However, with the deployment of new techniques the trend of increasing energy consumption can be slowed. For instance Imperial Oil Cold Lake has a cumulative steam-oil ratio of about 3.3—notably lower than the average of other CSS operations, which are about 4.5. Furthermore the Imperial CSOR has remained relatively constant over the past eight years. An important driver of the lower energy use per barrel for this operation has been the combination of a relatively good quality reservoir and the application of advanced reservoir modeling techniques coupled with the implementation of followup recovery technologies.

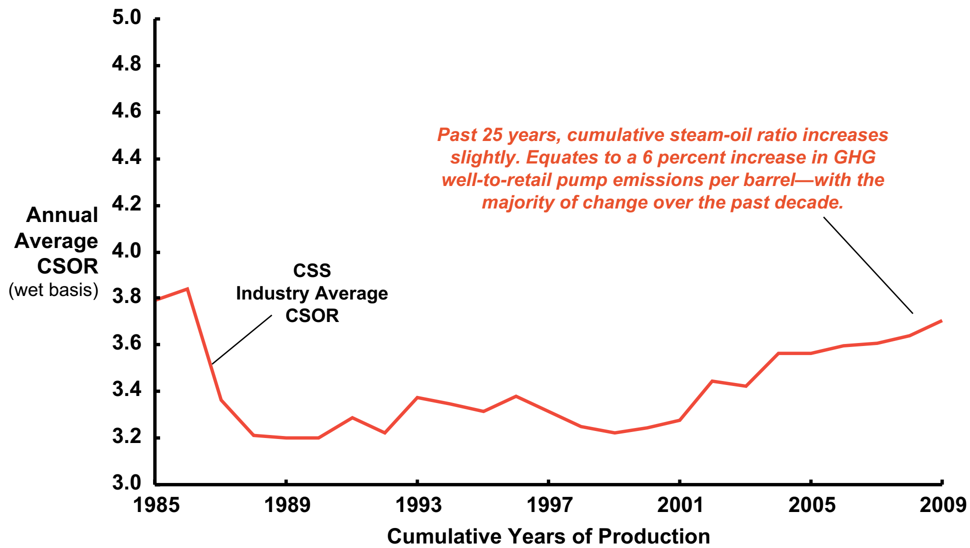
*Assumes SOR of 3.

**Assumes SOR of 3.

***The production-weighted annual average CSOR was calculated across all CSS projects. The average CSOR between years three and six was compared with the average CSOR in the past four years. The GHG emissions do not account for electricity cogeneration.

**Figure 7**

**CSS Projects: Progression of Cumulative Steam-to-oil Ratio**




Source: ERCB, IHS.
Notes: Projects included in average are Imperial Oil Cold Lake (1985), CNRL Primrose/Wolf Lake (1985), and Shell Canada Peace River (1996). The production-weighted annual average CSOR was calculated across all CSS projects. The average CSOR between years three and six was compared with the average CSOR in the past four years.
01212-3

## Water Consumption

Originally CSS operations used as much as three barrels of fresh water per barrel of bitumen produced, all from fresh surface water sources. In the early 1990s new practices for storing produced water and using brackish water were adopted which reduced water demand.

Currently net water use per barrel averages about 0.6 barrels of fresh water per barrel of bitumen. About 10 percent of the water consumed comes from brackish sources. For the past five years over 95 percent of the produced water has been recycled.*

*Data for Imperial Cold Lake operation only, about 70 percent of total CSS production.

# PART III: FUTURE TECHNOLOGY DRIVERS FOR OIL SANDS

*Discovery consists of seeing what everybody has seen and thinking what nobody has thought.*

–Albert von Szent-Gyorgy

The emergence of oil sands as a commercially competitive resource is the result of innovation. Challenges remain, such as reducing the environmental footprint of oil sands production. This section reviews the breadth of innovation being applied within the industry to further improve the efficiency of converting the oil sands resource into a barrel of bitumen or SCO, along with other factors with the potential to push back on future improvements. The challenge is to relieve the environmental intensity while maintaining or improving the economic viability of oil sands production.

## THE DYNAMICS OF OIL SANDS RESERVOIR QUALITY

It is important to recognize that external factors are apt to push back on part of the technical gains described in this section. The first generation oil sands projects selected the very best parts of the oil sands deposit, with characteristics that could provide the most profitable recovery. For mining projects the first operators picked locations with oil sands that were close to surface and rich with bitumen. The next phase of mining projects generally involves lower quality resources (see Figure 8).

For the remaining economically recoverable in-situ oil sands resource the trend is also toward lower quality reservoirs. However, the in-situ reserves are bigger than mining, measuring 135 billion barrels, or enough bitumen to sustain production levels of 4 mbd for close to 100 years.* With a resource this immense, there will surely be a mix of higher and lower qualities reservoirs developed over the coming decades. However, considering the combination of aging first generation projects and the tendency for the best parts of the reservoir to be developed first, a general future trend toward lower-quality reservoirs is expected.

Considering the effect of lower reservoir quality for new mining and in-situ projects, if all other things are equal, the average energy consumption per barrel produced would increase. However, the critical question is, will all things be the same? Technology offers the chance to offset this trend to varying degrees.

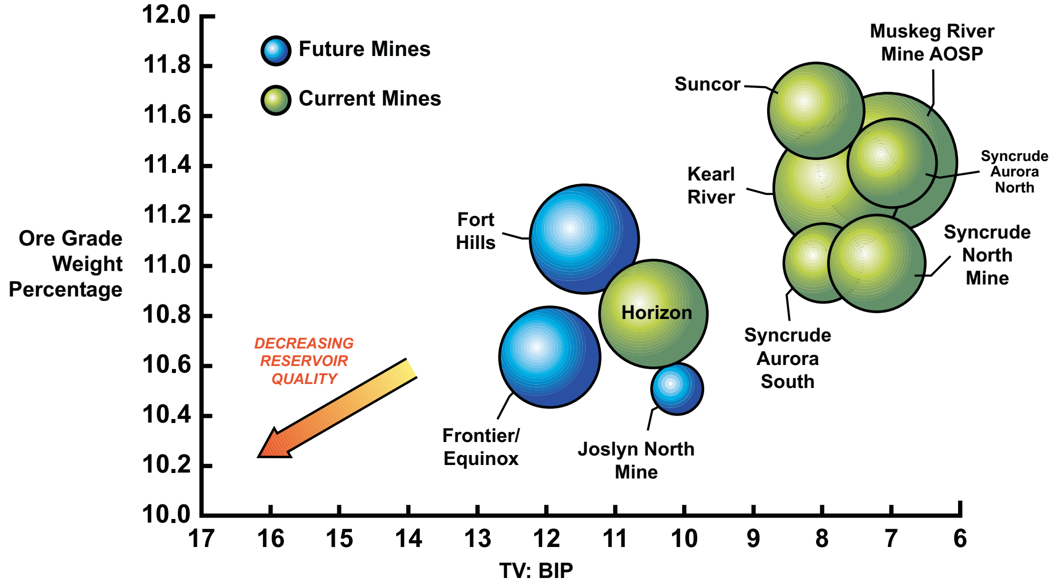
## NEW TECHNOLOGY'S POTENTIAL TO FURTHER IMPROVE ENVIRONMENTAL PERFORMANCE

A wide range of technologies is under development in the oil sands. Not all of the technologies highlighted here will become commercial; many face significant technical and commercial challenges. However, the process of innovation and experimentation is likely to help improve the efficiency of converting the oil sands resource into a barrel of bitumen

*Alberta Energy Reserves 2009 and Supply/Demand Outlook 2010-2019, Alberta ERCB.

**Figure 8**

**Changing Reservoir Quality: Mining Projects**




Source: IHS CERA.
Data sources: Oil Sands Review August 2010, & Macquarie Securities and companies websites, investor materials.
Notes: Frontier and Equinox are based on high estimate of recoverable reserves.
00807-1_0510

or SCO over time—decreasing GHG emissions intensity, natural gas demand, and water intensity. The potential benefits quantified here do not consider the possible effects from lower reservoir quality.

## GHG Emission Intensity

One of the key pressure points in oil sands developments is GHG emissions. Over the next two decades there will likely be two main methods of reducing emissions per barrel produced—one is to increase the energy efficiency of oil sands production, the other is CCS. Longer term, radically new methods of producing oil sands or generating steam more efficiently could take hold.

### *Evolutionary Methods: Improving Efficiency*

Through a process of continuous improvement, down-hole production, mining extraction, and surface facilities will evolve. The incentive to reduce energy use is large; reducing energy consumption notably improves both oil sands economics and reduces GHG emissions—a win-win scenario. Over the next two decades potential well-to-retail pump GHG intensity reductions of around 5 percent for mining and 5 to 20 percent for in-situ production are possible.

See the box "Evolutionary Mining and In-situ Technologies" for more details on the technologies that could further reduce GHG emissions for oil sands production.

## Evolutionary Mining and In-situ Technologies

**Mining and Upgrading Operations—5 Percent GHG Intensity Reduction (well-to-retail pump)**

Although mining is the most established oil sands recovery technology, more environmental improvements are expected. Potential energy-saving improvements include

- **Improved extraction.** The newest phases of mining projects are deploying more efficient variations of the asphaltenes extraction process first used in the AOSP phase 1. For mining and upgrading operations this technology is projected to reduce the emissions per barrel a further 2.5 percent (well-to-retail pump).
- **Heat integration.** Energy savings from increasing the heat recovery are probable. The goal is to recycle and recover more of the energy from the hot water postextraction, instead of sending the valuable heat directly to tailings ponds.
- **Mobile crushing units.** Another innovation is to use mobile crushing units to prepare the ore and bitumen mixture for transportation via pipeline at the mine face, instead of using large trucks; by eliminating the trucks, energy is saved. Commercial-scale trials have been under way for over three years and have led to changes in crusher designs. However, no operation has yet announced a large-scale transition to this technology. By eliminating most of the mining trucks, mining emissions per barrel from upgrading and mining operations could be reduced by 2.5 percent (well-to-retail pump).[1]

**In-situ Production—5 to 20 Percent GHG Intensity (well-to-retail pump)**

Improvements to in-situ recovery have the potential to make a noteworthy dent in GHG emissions per barrel produced.

- **Improved efficiency.** Today's in-situ production methods have the potential to reduce GHG emissions per barrel by 5 to 10 percent (well-to-retail pump). Improvements now emerging that help support these reductions include more robust electrical submersible pumps (able to better withstand the harsh wellbore conditions), in-fill wells, improved reliability, more heat integration in steam facilities, more advanced reservoir modeling and management (for instance, improving steam chamber optimization), and the potential for even lower-pressure operations.
- **Hybrid solvent-steam technologies.** Now undergoing trials in both SAGD and CSS operations, these methods inject solvent and steam into the reservoir. These techniques have the potential to reduce GHG emissions per barrel by more than 10 percent (well-to-retail pump). Solvent-aided SAGD is being used in some SAGD wells at the Cenovus/Conoco Phillips Christina Lake operation. Initial results are impressive. With only a minimal amount of solvent makeup required (0.05 barrels of butane per barrel of bitumen), a 30 percent increase in the production rate has been recorded—reducing both the steam-oil ratio and the GHG emissions per barrel of bitumen produced.[2]

  Solvent addition has also been successful in the CSS process at Cold Lake. Imperial Oil has now entered the commercial phase of solvent addition after two successful pilot cycles. Imperial's Liquid Addition to Steam to Enhance Recovery (LASER) process injects 3 to 8 percent diluent with the steam, and a 25 percent reduction in GHG emissions per barrel produced has been recorded.[3]

**Evolutionary Mining and In-situ Technologies (continued)**

Solvents have potential; however, the key to industrywide adoption will hinge on economics. To work economically, solvent use must be minimized—it is an expensive additive. The recovery must be maximized—most of the solvent injected into the reservoir needs to be recovered and reused—and in some field trials solvent recovery has been a challenge. On Suncor's Firebag pilot, just 8 to 41 percent of the solvent injected was recovered.[4] Finally, operators need to acquire solvent supplies at reasonable prices. If solvent technologies are adopted widely, this could lead to supply shortages, higher solvent prices, and more pressure on solvent economics.

1. The AOSP project (starting up in 2010) and the Imperial Kearl mining project (now under construction) are both deploying lower-energy variations of the AOSP phase 1 paraffinic froth treatment process. This process reinjects a fraction of the asphaltenes in the bitumen. Shell Canada's 2006 Sustainability Report states that the new, lower energy paraffinic froth treatment technique is expected to reduce energy use per barrel extracted by 10 percent, or 2. 5 percent well-to-retail pump, for mining and upgrading operations.
2. Source: Cenovus Presentation, Barclays Capital 2010 CEO Energy-Power Conference, September 16, 2010.
3. Imperial Presentation, Responsible Development of Canada's Oil Sands, Toronto Board of Trade, May 26, 2010 and ERCB report on LASER, April 16, 2010.
4. Source: ERCB, operator progress reports, Athabasca Suncor Firebag, April 30, 2008.

## New Production Methods

Longer term, completely new methods of producing oil sands offer the possibility of greater reductions in GHG emissions per barrel produced. In-situ offers the most potential for revolutionary new production methods, as many methods are under development. Some new production techniques use alternatives to steam for mobilizing the bitumen including warm solvents, electricity, and even creating a fire within the reservoir.

Although the potential environmental benefits from these methods are still somewhat uncertain, considering the spectrum of new methods under development GHG emissions intensity reductions in the range of 20 percent or greater are possible (well-to-retail pump).

See Table 3 in the next section for specific examples of potential new oil sands production techniques and benefits.

## Carbon Capture and Storage

In the oil sands the lowest-cost $CO_2$ capture opportunity is at the upgrader; at either the hydrogen plant or the gasifer. Capturing $CO_2$ at the upgrader hydrogen plant reduces GHG emissions per barrel by between 11 to 14 percent (well-to-retail pump).*

Implementing carbon capture and storage (CCS) increases capital and operating costs substantially. Capture and storage of $CO_2$ at the hydrogen plant is estimated to cost between $500 and $700 million for a 100,000 barrels per day upgrading facility, and equipping a

*IHS CERA assumes that parasitic load from the CCS equipment increases energy use by about 30 percent, thus decreasing the impact of $CO_2$ capture. For the hydrogen plant retrofit we assume that after parasitic losses are considered, 40 percent of the emissions associated with the upgrading portion of the value chain are captured with CCS.

gasification plant for CCS is likely to exceed $1 billion, in addition to the $1.5–$2 billion cost of building the plant. Translating these capital costs into dollars per ton of GHG abatement costs suggests that $CO_2$ prices (or taxes) would need to exceed $50 per metric ton of $CO_2$ for capture at the hydrogen plant and nearly $100 per metric ton of $CO_2$ for CCS on a gasification plant to economically justify the additional expenses. Some studies find even greater carbon capture costs—in excess of $150 per ton.

Longer term, capture of postcombustion $CO_2$ emissions in oil sands provides the possibility of reducing emissions beyond the upgrader. However, at present capture of postcombustion GHG emissions (which are low pressure and dilute) is considerably more expensive (both capital and operating costs are higher). Significant energy and equipment are required to separate and compress the $CO_2$, which makes the process costly and, depending on the power generation source used for capture, reduces the net GHG emissions benefit of the abatement.

Although costs are currently high and in the medium term wide-scale of CCS seems unlikely, globally and across many industries research into CCS is under way. Over a longer time horizon and through these efforts, we expect the cost of CCS to decline. In total the Alberta and Canadian federal governments have placed C$3 billion of investment in demonstration projects aimed at proving up the carbon capture technologies from both technical and economic perspectives. The effort remains a linchpin in the government's efforts to curtail $CO_2$ emissions from the oil sands industry and other industries in Alberta over the longer term. With government support, in the next decade it is probable that at least one CCS project will be operating in the oil sands. See the box "CCS Technologies and Projects" for details.

## Reducing Natural Gas Demand

Natural gas is the primary fuel used for steam generation in oil sands processes. Using less natural gas lowers costs and reduces GHG emissions. Oil sands currently account for just over 20 percent of Canadian natural gas demand. Under a moderate oil sands growth scenario this could increase to 25 percent, and under a "stretch case" scenario this could grow to 40 percent of Canadian gas demand by 2035.*

Periods of high gas prices have led to the pursuit of alternative fuels such as gasifying petroleum coke or bitumen bottoms (by-products of oil sands upgrading) or burning a portion of the produced bitumen to raise steam. But today the industry has moved into a new era of expanding domestic gas supply and low gas prices. The "shale gale" is the result of a technological breakthrough in the commercial exploitation of massive shale gas deposits in North America, and this has changed expectations about the future cost profile of North American natural gas (see the box "Natural Gas Raises the Bar for Competing Fuels"). With expectations of low natural gas prices, the economic bar that alternative fuels must overcome to compete with natural gas is high. Using bitumen (or by-products) for fuel is not only challenged on the economic front, it is also tested on environmental grounds, as options that use bitumen or its by-products generate about double the GHG emissions

*The high growth scenario is a stretch case for oil sands growth, with production of 6.3 mbd by 2035. The moderate growth case assumes oil sands production of 3.1 mbd by 2035.

## CCS Technologies and Projects

**Oil Sands Upgrader CCS—Potential of 11 to 14 Percent Reduction in GHG Intensity (well-to-retail pump)**

There are two CCS projects under consideration for oil sands upgraders, both in the Edmonton area. Edmonton is home to 25 percent of oil sands upgrading capacity—the remainder is more than 400 kilometers (km) away, near Fort McMurray.[1] One CCS project is in the planning phases, while the other is at a conceptual stage. Both projects have sizable financial commitments from the Alberta government.[2]

Beyond the Edmonton upgraders, the challenges of CCS are more formidable. There are no geologically suitable carbon storage locations in the Fort McMurray region—therefore a pipeline to transport $CO_2$ from the oil sands region to more suitable storage locations (200 to 400 km away) is required. Central Alberta provides a plethora of opportunities for using $CO_2$ for enhanced oil recovery (EOR), a method to improve recoveries of conventional oil. Although there are numerous large $CO_2$ sources in central Alberta, which are much closer to the potential EOR opportunities than the Fort McMurray upgraders, the construction of a $CO_2$ pipeline is not outside of the realm of possibly. A pipeline project currently being advanced aims to transport $CO_2$ from the Fort McMurray region; transportation of GHG emissions over this distance has been estimated to add in the range of $10 to $20 per metric ton of $CO_2$ to the cost of CCS.[3]

**CCS from Dilute Postcombustion Exhaust Streams**

Postcombustion exhaust streams are dilute (only 5–15 percent $CO_2$) and low pressure. Even with a hypothetical high cost of carbon, the economics are unfavorable because of the high capital, operations, and energy costs of CCS for dilute streams. Numerous technologies are now under development with potential to lower both the cost and the energy required for capture and compression, but no clear winner exists today. These technologies include

- **Postcombustion recovery using new stripping agents.** Today mine scrubbers can capture the dilute combustion streams technically, but high parasitic losses associated with regeneration of the amine stripping agent make for questionable economics. Current research is under way to develop new stripping agents, such as chilled ammonia or advanced amines, that could be more efficient and potentially more cost effective.

- **Oxy-fuel combustion.** A precombustion process that uses pure oxygen for combustion instead of air results in a combustion stream that is 95 percent or more $CO_2$—obviously much more amenable to separation than a dilute stream. The main detractor for this option is the requirement for a capital- and energy-intensive air separation plant to produce oxygen. In 2012 a test of oxy-fuel combustion is planned for an in-situ oil sands site; this is a joint industry and government initiative that is testing capture only—the project does not include $CO_2$ storage.[4]

- **Integrated gasification combined-cycle.** This is a variation of traditional gasification. Instead of air, this process uses oxygen as a combustion medium that produces a more pure $CO_2$ stream; but this is at the expense of large parasitic energy losses.

- **Chemical looping.** This process involves a reactor that uses an oxygen carrier to create a postcombustion stream of pure $CO_2$. This process is now being demonstrated at pilot scale.

1. Two upgraders near Edmonton are AOSP phase 1 and phase 2. Phase 2 is currently under construction and slated for start-up in early 2011.
2. The AOSP CCS project, called Quest, has C$745 million of funding under the Alberta government's C$2 billion dollar Carbon Capture and Storage Fund. The Northwest upgrader, which has not yet commenced construction, has signed a letter of intent for a CCS project valued at C$495 million.
3. http://www.ico2n.com/what-is-ccs/ccs-economics/transport-economics.
4. This project is part of the $CO_2$ Capture project, a partnership of energy companies, academia, and government.

**Natural Gas Raises the Bar for Competing Fuels**

The North American natural gas industry has undergone a metamorphosis in the past five years. IHS CERA calls this the shale gale.

Around the middle of the past decade natural gas supplies seemed under severe pressure from declining North American conventional gas supplies and high and volatile pricing, aggravated by a series of severe hurricanes in the Gulf of Mexico. Common expectations for future natural gas prices were \$8–10 per million British thermal units (MMBtu)—a level at which alternatives become attractive in the oil sands, especially in-situ projects. Concerns about gas supply at that time led to a build of regasification capacity in the United States for an expected wave of liquefied natural gas imports.

How times have changed. Unconventional gas in the form of shale gas has boosted supplies, driven by major technological advances in directional drilling and fracturing technologies. There is now a longer-term prospect that almost 15 billion cubic feet per day (Bcf) of US base-load regasification facilities will lie idle for a very long time.

Unconventional gas resources have been known for a long time, but only with recent technology advances can they now be exploited economically. Indeed most current shale plays are more economical than conventional gas plays: hence the downward pressure on natural gas prices in recent years as almost 10 Bcf per day, or almost 20 percent of US gas supply, has come into production since 1997. These shale plays are common in North America; they extend all the way from Texas along the Appalachians to New York and continue into eastern Canada. In addition at least two large economic shale plays have been discovered in Alberta and British Columbia—the Montney play and the Horn River play.

The result is that the outlook for natural gas supply and price has changed dramatically in recent years, with long-term gas prices now estimated to remain in the \$5–6 per MMBtu range.

compared with natural gas. High GHG emissions and the shale gale have diminished the likelihood of alternatives' displacing natural gas in the coming decades.

The outlook for low natural gas prices has also raised the economic bar for some new oil sands production methods. For example use of new hybrid solvent-steam technologies for in-situ production results in extra costs for purchasing, handling, and recycling solvents. This is offset by reduced demands for natural gas that result from lower SORs when using solvents. However, if the cost of natural gas is low, the economics for hybrid solvent are more challenged as the economic advantage of reducing natural gas demand is diminished. A similar problem exists for other production methods that do not use natural gas.

Using zero carbon–emitting technologies as an alternative to natural gas still holds appeal. Small nuclear plants have the highest potential to achieve the vision of no carbon emissions for oil sands production. But even with the most optimistic development scenario and assuming the technology is both economic and practical, deployment is more than 20 years away.

## Reducing Water Consumption

For both oil sands mining and in-situ operations, the volume of water required to produce a barrel of bitumen is projected to decline.

### *Mining Water*

There is potential for incremental declines in mining water intensity. For instance, the next phase of mining projects are deploying a more efficient oil extraction and froth treatment process expected to reduce water consumption per barrel by 10 percent.*

Still, the biggest prospect for reducing water consumption in mining operations comes from liberating the water trapped in the tailings. About four barrels of fresh water are consumed for each barrel of bitumen extracted. This water is trapped in the tailings ponds, tightly bonded with fine sands. Two new tailings technologies have been announced in the past year, and both offer the potential to recover some of the water from tailings. Suncor has introduced Tailings Reduction Operations and Shell has also announced a new tailings treatment process. However, even if the tailings water is recovered, it must still be treated and cleaned before it can be reused for mining extraction. Today, water-treatment technologies for cleaning the water exist, but they are expensive. An alternative to reusing the water in the mining operations is to use the tailings water for in-situ production; here the processes can handle less pure water.

In the longer term (20 years and beyond) the future for mining could lie in nonaqueous extraction methods. At present these techniques are in the research and developmental stage.

### *In-situ Water*

The biggest driver for reducing water demand for in-situ production is to lower the SOR—the same driver as with GHG emissions. With improved efficiency in the existing in-situ processes, SOR (and thus water demand) could be reduced by 10 to 20 percent per barrel produced. If hybrid steam solvents are used for in-situ production, a further 25 percent or more reduction in water demand is possible.

Another way to reduce water demand is to further improve the amount of produced water that is recycled. Already some new sites are deploying the combination of evaporators and drum boilers, or ZLD systems—here recycle rates between 90 and 95 percent are achievable. However, for sites already installed with the more established OTSG technology, there is still potential for further improvements. For instance a new technique is being trialed that could theoretically reduce OTSG net water use from 0.9 barrels of water per barrel of bitumen produced to 0.3—equivalent to a 90 percent recycle rate.**

*The AOSP project (starting up in 2010) and the Imperial Kearl mining project (now under construction) are both deploying lower-energy variations of the AOSP phase 1 paraffinic froth treatment process, which is expected to save energy and water for extraction.
**Assumes SOR of 3. The technique involves rerunning the OTSG blowdown or wastewater stream through a second boiler, generating more steam and decreasing the size of the blowdown.

Over the past decade the industry has shifted from consuming mostly surface and fresh groundwater to using increasing volumes of brackish water. Ultimately reducing water consumption and increasing volumes of brackish water is a trade-off between energy use and fresh water consumption. The use of brackish water generally results in higher water treatment costs, greater energy consumption (as much as 10 to 30 percent more energy for the water treatment step), and more waste.* Although using larger volumes of brackish water typically requires more energy, it's important to keep the energy consumption in perspective—more than 90 percent of the energy consumed in producing a barrel of bitumen comes from generating steam to inject into the reservoir, not from water treatment.

In the next 15 to 20 years a number of the revolutionary new production methods, including in-situ combustion and warm solvents, offer the possibly of producing in-situ oil sands with no water use (see Table 3 for details on revolutionary new production technologies).

## REVOLUTIONARY PRODUCTION TECHNOLOGIES

This section highlights a spectrum of completely new in-situ oil sands production techniques that are in various phases of development. The technologies highlighted in Table 3 are not exhaustive. All of the technologies listed must still achieve commercialization—overcoming economic, technical, and environmental hurdles. The potential environmental benefits from these methods are still somewhat uncertain, however. Considering the number of ideas under development, some of these ideas are likely to take hold, helping to decrease the environmental footprint of production while unlocking new parts of the oil sands deposit—bitumen that is currently not recoverable (see the box "Unlocking More of the Massive Oil Sands Resource").

*The exception to this general rule is in shifting steam generation technology from OTSG/lime water treatment to the evaporator/drum boiler combination. With the higher efficiency of drum boilers, the overall energy consumption can be reduced.

**Table 3**

**Examples of Revolutionary In-situ Technologies**

| Technology | Potential to Unlock New Parts of the Oil Sands Deposit | Status |
|---|---|---|
| **In-situ combustion technology** produces bitumen using heat generated within the reservoir from combustion—effectively burning about 10 percent of the bitumen to recover the rest. The heat from combustion reduces the bitumen's viscosity and mobilizes the bitumen. Due to the combustion, the product is partly upgraded.<br><br>After initial start-up, the process does not require an external source of heat to mobilize the bitumen. Potential benefits over today's SAGD include low water demands and lower GHG emissions intensity.<br><br>Examples of firms pursuing variants of this process include Petrobank's THAI™ with a field pilot under way—this project is already producing bitumen—and Petrobank has four other projects planned. Athabasca Oil Sands Corporation (formerly Excelsior Energy) is developing a second variant called combustion overhead gravity drainage—a pilot is planned for 2011. In-situ combustion is also being researched at Calgary Center for Innovative Technology at the University of Calgary. | Reservoirs that are too thin | Field pilot |
| **Pure solvent technology** involves injection of pure solvents (not steam) to mobilize the bitumen. The solvents are injected warm and result in partial deasphalting of the bitumen, creating a lighter product.<br><br>Potential benefits include notably lower GHG emissions and no requirement for water. The process could require significant volumes of solvent.<br><br>An example of a firm pursuing this concept is N-Solv Corporation. The N-Solv process is low energy; it operates at 40°C (much lower than current in-situ methods which are often over 200 °C). | Access reservoirs without cap rock, too thin, with low pressure gas cap, and at intermediate depth | Conceptual |
| **Electric heating processes,** energy is transferred to the bitumen by electricity. Depending on the electrical current applied, the energy can be transferred numerous ways—dielectric heating, resistive heating, or inductive heating. Some methods require water (to transfer the heat). One potential sweet spot for this technology is areas of the oil sands deposit that are too deep for mining but too shallow for thermal in-situ processes. | Access intermediate depth reservoirs, insufficient cap rock, and low pressure gas cap, and carbonates | 2010 field tests planned |

**Table 3**

**Examples of Revolutionarily In-situ Technologies (continued)**

| Technology | Potential to Unlock New Parts of the Oil Sands Deposit | Status |
|---|---|---|
| **Electric heating processes** (continued). It is still uncertain if electric heating technology can provide lower GHG intensity compared with today's SAGD. Although the reservoir temperature is notably lower (potentially less than 100°C), depending on the fuel used to generate electricity, the GHG intensity could still be comparable with today's SAGD. Depending on the technique, water use should be lower than today's SAGD.<br><br>A number of electric heating processes are under development, one method is being developed by ET Energy. In the ET process, electrodes are arranged in a close-knit grid with extraction wells at the center of each grid. A second technique is being developed by Siemens—it uses electric heaters. The Siemens heaters could possibly be combined with SAGD in a hybrid process called EM-SAGD. Shell has also conducted research and pilots using electric heating concepts. Recently, Athabasca Oil Sands Corporation announced an electric technology called thermal assisted gravity drainage—they plan to pilot the use of electric heat for bitumen extraction in the carbonate reservoirs. | | |
| **Hybrid solvent extraction and electric heating** technology combines the electric heating and pure solvent extraction methods. The process is low energy, operating at about 50°C, and does not require water.<br><br>Potential benefits over today's SAGD include lower GHG emissions and no water requirement. The process could need significant volumes of solvent.<br><br>This technology is being developed in partnership between operators and technology providers including Nexen, Laricina Energy, Suncor Energy, and Harris Corporation. This technique is called enhanced solvent extraction incorporating electromagnetic heating. | Access reservoirs without cap rock, too thin, with low pressure gas cap, and intermediate depth | Field pilot planned (2+ years) |
| **Underground tunnels** technique targets reducing the surface disturbance from development while increasing operating and thermal efficiency. The tunnel includes a main shaft for surface access, combined with branching tunnels which are drilled beneath the target formation. Conventional SAGD wells are drilled from the tunnel up into the formation. With this approach, the oil is drained downward from the formation and therefore operations can be conducted at very low pressures—leading to numerous process efficiencies. Further the gathering system is not exposed to the atmosphere, which reduces thermal losses. This method was used for AOSTRA's first SAGD pilot. | Access carbonate reservoirs, intermediate and shallow depth, and areas with surface restrictions | Conceptual |

**Table 3**

**Examples of Revolutionarily In-situ Technologies (continued)**

| Technology | Potential to Unlock New Parts of the Oil Sands Deposit | Status |
|---|---|---|
| **Underground tunnels** (continued). Advantages are expected to include lower SORs and correspondingly lower water and energy requirements. Land disturbance should be significantly less.<br><br>This technology is currently being developed by OSUM Oil Sands Corporation. OSUM is proposing this method for recovering bitumen from the carbonate reservoirs. | | |
| **Gas cap combustion** is a new method being tested to produce bitumen that is in communication with a low pressure gas zone. Air is injected into the gas reservoir, and a combustion zone is initiated; the resulting heat is transferred to the bitumen below, mobilizing it.<br><br>Cenovus plans to pilot test this concept in 2012.* | Communication with low pressure gas cap | Field pilot planned (2012) |

Source: IHS CERA.
*Cenovus Presentation, Barclay Capital 2010 CEO Energy-Power Conference, September 16, 2010.

**Unlocking More of the Massive Oil Sands Resource**

Using today's surface mining, SAGD, and CSS methods, only 10 percent of the bitumen-in-place is expected to be recovered. A study by the Petroleum Technology Alliance Canada (PTAC) estimated that more than half of the bitumen-in-place (1 trillion barrels) is not accessible at all with current production methods.* The following list highlights the reservoir types that currently cannot be produced. The revolutionary new oil sands production technologies under development—shown in Table 3—have the potential to extract bitumen from these more challenging reservoir types.

- **Thin reservoir.** About 410 billion barrels of bitumen-in-place is found in sand deposits that are too thin for economic SAGD production (less than 10 meters [m] in thickness); the thin reservoirs result in costly heat loss into other formations. Moreover it is technically difficult to "fit" the stacked SAGD well pairs into these thin pay zones.
- **Carbonate rock.** About 477 billion barrels of bitumen-in-place is found in carbonate rocks or limestone, not sand. The carbonate rocks have discontinuities and fractures; these can make the containment of steam a challenge, but these fractures can also provide benefits, increasing the porosity and permeability of the reservoir. A number of pilots ran in the 1980s with varied success, but now this resource is being revisited, with a number of new pilots planned.
- **Insufficient cap rock.** Around 36 billion barrels of bitumen-in-place is in sand deposits that lack an overlying cap rock that seals the top of the deposit. Without a cap rock the steam escapes and transfers energy to non–bitumen-bearing formations.
- **Intermediate depth.** About 28 billion barrels of bitumen-in-place are contained in pay zones that are too deep for mining and too shallow for thermal recovery (defined as oil sands at depths between 40 m to 75 m).
- **Communication with low pressure gas cap.** Around 14 billion barrels of bitumen-in-place are overlain and in communication with shallow gas reservoirs. This bitumen is difficult to produce with SAGD methods as the steam can escape to the low pressure gas zone above.

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*Source: *Expanding Heavy Oil and Oil Sands Resources While Mitigating GHG Emissions and Increasing Sustainability,* PTAC, May 2006.

# PART IV: WHERE IS THE INDUSTRY HEADED?

New ideas in oil sands extraction are not in short supply, and ongoing improvements from deploying new technologies are likely. But what do these individual improvements mean for the industry as a whole? How can the successful deployment of new technologies (or tweaks to existing processes) change the cumulative impacts from the oil sands industry over the next two decades and beyond? Where will future innovations come from and who will fund this research?

## NEW TECHNOLOGY: SLOW RAMP-UP TO INDUSTRYWIDE BENEFITS

Economic evolutionary technologies that can be applied to existing oil sands facilities are often rapidly adopted. The pace at which revolutionary technologies are adopted, however, is slower.

Even when revolutionary technologies can navigate the difficult and lengthy hurdles to commercialize the first facility (starting with initial success in the laboratory, then gaining access to an oil sands lease for a field pilot, then successfully raising hundreds of millions of dollars to fund the multiyear process of regulatory approval construction and operation of the pilot), there is a further time lag before the industry adopts these technologies and industrywide benefits become evident.

The most recent revolutionary development in oil sands extraction, SAGD, presents an example. After successful pilots in the mid-1980s, it took 15 more years before the first commercial project started and a further 5 years before the production from SAGD reached 5 percent of total oil sands production (see Figure 9). Thus it took more than 20 years to go from field pilot to having a substantive affect on the industry as a whole. Undoubtedly part of this was the result of a decade of relatively weak oil prices following the discovery of SAGD combined with the need for advancements in horizontal drilling—a technique that was only first introduced in its present form in the mid- to late 1980s.

The lag between the invention of a commercial technology and the realization of substantive environmental benefits is highlighted by one of the IHS CERA oil sands future scenarios—New Social Order.* In this scenario strong government policies limit GHG emissions, and oil sands growth is moderate, leveling off at around 3.1 mbd by 2020.**

In this scenario, a true stretch case for oils sands innovation, technology enables a paradigm shift for oil sands. Highlights of major innovations are

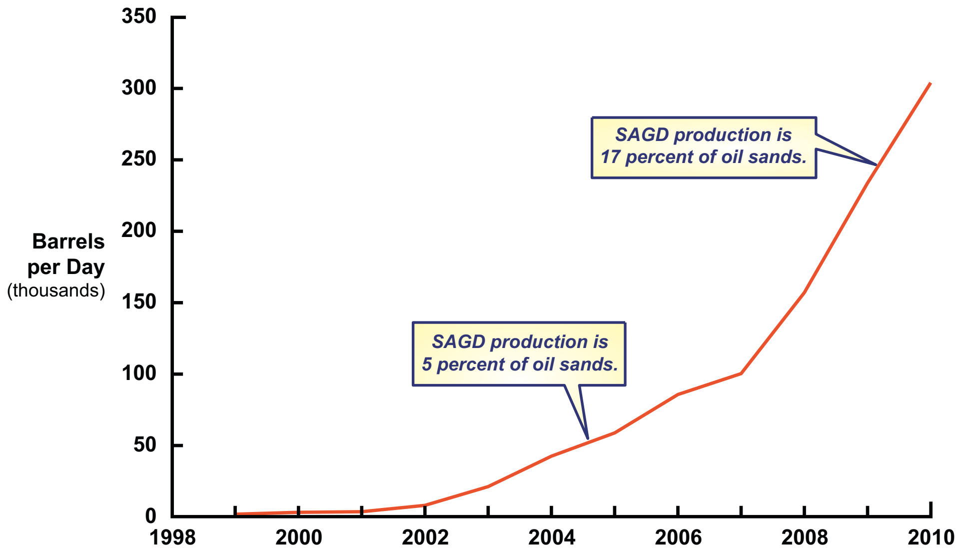
- **In 2020 the industry and government collaborate to fund the construction of a network of gathering pipelines to aggregate $CO_2$** and transport it via pipeline to Central Alberta for use in EOR projects.

*For more information on IHS CERA's future scenarios see the IHS CERA Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance.*

**A high price for emitting carbon is one factor driving innovation, but it is not the only one. By 2020 carbon costs reach $100 per metric ton (constant 2008 dollars).

**Figure 9**

**SAGD Production Growth**




Source: IHS CERA.
Note: 2010 average production January to May 2010, Athabasca deposit production only.
01006-6

- **By 2035 more than half of all upgraders capture $CO_2$ (at the hydrogen plant or gasifier).** Economic postcombustion technologies on upstream facilities are not developed in this time frame.

- **New, low-emission, revolutionary, in-situ extraction technologies just start to be deployed commercially post-2030.**

- **Small nuclear plants are used on the first SAGD site as an alternative to natural gas for steam and electricity generation in 2030.**

- **By 2035 the aggregate SOR for SAGD is reduced to 1.8 though a combination of ongoing efficiency improvements and successful industrywide implementation of hybrid steam-solvent technologies.** Technology effectively dampens the effects of lower reservoir quality and provides major gains in SAGD efficiency.

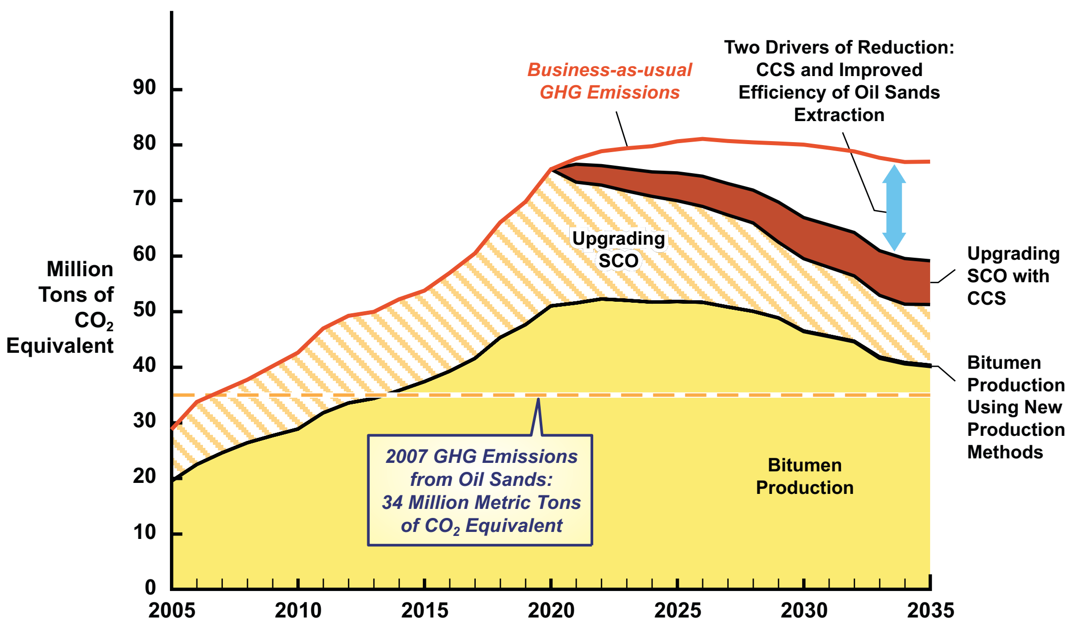
- **By 2020 new methods allow mining operations to reduce GHG emissions by 10 percent compared with 2010 levels.** These gains are maintained despite lower-quality mining reservoirs.

How does this aggressive technology scenario affect the GHG emissions from oil sands upgrading and extraction? Emissions grow in sync with production, both nearly doubling from the current level by 2020 when oil sands growth plateaus. Post-2020 major innovations start to chip away at the aggregate emissions. Over the next 15 years industrywide emissions from producing and upgrading oil sands are down 23 percent from peak, and GHG intensity per barrel produced is down even more—over 30 percent (see Figure 10). Nearly all of the GHG reductions stem from two areas: increased energy efficiency in oil sands extraction (two thirds of the improvement) and using CCS on oil sands upgraders (one third). By 2035 other, more revolutionary innovations are just starting to be deployed more widely—but they do not yet have a material impact on the industry in aggregate. Nuclear is deployed for 3 percent of the production in 2035, and low energy (nonsteam) in-situ extraction technologies also account for 3 percent. Now these newly commercial, revolutionary technologies are becoming established and setting the stage for major improvements over the following decades. In this, a stretch case for oil sands innovation, although the emissions per barrel decline significantly, oil sands production more than doubles, and aggregate emissions from oil sands still grow. Compared with today, emissions from oil sands grow from about 5 percent of Canada's emissions (40 million metric tons [mt] of $CO_2$-equivalent for 1.35 mbd of oil sands production) to about 10 percent by 2035 (60 mt of $CO_2$-equivalent for 3.1 mbd of oil sands production).

Although emissions grow, clearly extraction of any oil takes energy. Substituting oil sands supply for another source still results in emissions. For instance, producing 3.1 mbd of the average crude consumed in the United States results in GHG emissions of 44 mt of $CO_2$-equivalent.*

**Figure 10**

**New Social Order Future Scenerio—Oil Sands GHG Emissions**




Source: *Growth in the Canadian Oil Sands: Finding the New Balance*, New Social Order scenerio.
01006-8

*Emissions for production of the average crude consumed in the US (2005 baseline). See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right.*

## THE FUTURE OF RESEARCH AND DEVELOPMENT

Ongoing investment in research is critical to the future health of the oil sands industry—and the future could be lengthy. Just considering established reserves and assuming an oil sands production rate of 5 mbd, it would take more than 100 years to exhaust the currently recoverable resource. Consequently R&D should be a combination of both new breakthrough, revolutionary ideas that affect 20 years and beyond and the evolutionary improvements that shape both the short and the long term.

### Who Should Invest in R&D?

This is not an either/or question. Both publicly funded and privately funded research is critical to the future health of the oil sands industry. Research funding is a multitiered process ranging from fundamental academic research to demonstration trials through to applied research and pilot plants. Most fundamental research occurs in universities and some government laboratories. Applied research is conducted mostly by private companies (both oil companies and the service sector) but also to some extent by government agencies.

Many potential breakthroughs will require relatively high-risk, low-probability fundamental research that is by definition very long term. Basic research is essential for creating the building blocks for new solutions—concepts with potential for applications across a spectrum of industries. Individual companies do not have the resources or incentives to conduct this type of broadly applicable research; government investment is required. Advancement of these fundamental building blocks could position the oil sands industry (as well as other industries) for radically new approaches in the long term; research in areas such as nanotechnology, photonics, and biological systems all have potential application for oil sands (see the box "Looking in the Crystal Ball").

### Examples of Collaborative Public and Private Research

Investment is moving more into the realm of collaborative research. This strategy is preferable to operating in research silos. This not only avoids duplication of research and field pilot endeavors, it also leads to cross-fertilization and sharing of ideas. There are many encouraging signs of R&D collaboration within the oil sands industry—partnerships covering the spectrum of industry, academia, and government (both federal and provincial). The following list is not exhaustive but highlights some of the numerous initiatives under way:

- **Oil Sands Leadership Initiative** (OSLI). This is a collaborative research network between Conoco Phillips, Nexen, Statoil, Suncor Energy, and Total. The focus is to improve sustainability of oil sands development. Examples of current projects include research in synthetic biology and investment in sustainable communities.

- **Natural Sciences and Engineering Research Council of Canada (NSERC).** Research is a partnership between the Canadian government, industry, and academia. NSERC has a broad mandate to invest in research; specific oil sands research includes study of water quality for oil sands extraction and engineering fundamentals of extraction.

**Looking in the Crystal Ball**

The oil sands future is likely to be long. How could innovations in more broadly applicable fundamental research play a role over the very long term?

**Nanotechnology.** The manipulation of materials at the molecular level to create stronger, cheaper, and higher-performance materials, nanotechnology is already emerging from the laboratory to affect a range of commercial products. Ultimately nanotechnology could have an impact on many facets of oil sands extraction and processing, from the reservoir, water treatment, and reduction in oil viscosity to boiler designs, upgrading technologies, and improved recoveries of pollutants.

NanoAlberta is a provincially funded center for nanotechnology R&D and commercialization.

**Biological engineering.** Major advances in biotechnology and genomics in recent years are leading to renewed interest in biological solutions in resource industries and environmental remediation. These innovations could transform how oil sands are extracted and upgraded and could even destroy oil sands waste streams.

Application examples include bacteria that could eat the oil in the deposit, producing lighter hydrocarbons or even methane from the bitumen. Microbes could also upgrade the bitumen or destroy wastes. Microorganisms could consume wastes, eating $CO_2$ and turning it into valuable product such as food or fuel—a game changer compared to the prospect of long-term carbon storage.

**Photonics.** Using light in the application, examples include fiber optic telecommunications and medical lasers. Advancements in photonics could lead to improvements in oil sands observation and detection, allowing operators to more accurately visualize reservoir operations, optimize energy use, and maximize production.

- **Canadian Oil Sands Network for Research and Development (CONRAD).** The CONRAD research partnership involves about 30 organizations, including companies, government, and academia. The research focus is to advance oil sands technology.

- **Petroleum Technology Alliance Canada (PTAC).** This not-for-profit association facilities collaborative research in the energy sector. The current membership includes 26 oil and gas producers. PTAC conducts research oil sands as well as in the oil and gas sector overall.

- **CCEMC.** Under a government initiative, CCEME capital is raised by a levy on Alberta companies that emit more than a specified amount of GHG emissions.* In the first two years over C$120 million has been paid into the fund and will be invested collaboratively with industry and government on research into cleaner technologies.

- **Alberta Innovates—Energy and Environment Solutions (previously AERI).** Created recently as a central clearinghouse for publicly funded research within the province, historically its budget has been about C$16 million per year. Part of that is allocated to joint investments with industry on oil sands research.

*One compliance option is to pay the CCEMC fund C$15 for each ton of $CO_2$ emitted over baseline.

- **Carbon Capture and Storage Fund.** In 2010 the Alberta Department of Energy has approved four major CCS projects in Alberta for total funding of C$2 billion over four years.

- **The Innovative Energy Technology Program (IETP).** This program is administered by the Alberta Department of Energy. If fully subscribed, total spending by industry and government through IETP over more than eight years could exceed C$800 million, only part of which is focused on oil sands.

There is now a much broader acceptance within the industry and government that collaboration is beneficial—not only at the individual corporate level but also at the industry level. In an era of instant dissemination of information, a mishap at one operation can lead to a detrimental impact on the whole industry. The significance of this is not lost on the industry, as illustrated by an announcement by Shell about an environmental tailings reclamation technology. In its announcement, Shell reiterated that this technology would be made available at no cost to other industry producers—no fees, no royalties. Further to this announcement, other oil sands producers have publicized efforts to "join forces" and collaborate on advancing tailings technology development—pledging to remove both intellectual property and monetary barriers to sharing technology.*

## CONCLUSIONS: ONGOING IMPROVEMENT CREATING BENEFITS

The industry has established a track record of ongoing, continuous improvement, leading to better economics and lower environmental intensity. The historical pattern of successful oil sands innovation has always been a two-pronged approach: ongoing improvements to the existing processes combined with the periodic breakthroughs. The breakthroughs have not been accidental but do tend to be unpredictable and have been the result of large, up-front capital investments over the long term. Most often the large investments required for these breakthroughs have been a combination of public and private funding. Current investment in the oil sands is continuing this trend.

In a global context oil sands is a high-cost but competitive oil resource. Its growing role in world oil markets owes much to this process of continuous innovation. Mining methods have incorporated more conventional truck and shovel mining techniques, hydrotransport, and lower-temperature extraction processes. All have boosted productivity while reducing unit costs. New in-situ techniques have been developed, including SAGD. Currently hybrid steam-solvent processes are poised to have an impact on both the productivity and costs of SAGD and CSS extraction processes.

There is a growing appreciation that collaboration among industry players is beneficial—both in increasing the speed of innovation and in sharing the effects of new technology on reducing industrywide environmental impacts. This should help to increase technology development and the possible pace of implementation across the industry. There is increasing recognition that stakeholders view oil sands in the aggregate rather than as individual projects.

*Companies are Syncrude, CNRL, Imperial Oil, Shell, Suncor Energy, Teck Resources, and Total.

Ongoing environmental and economic improvements in oil sands extraction and upgrading are likely, but not inevitable. Any benefits must resolve the countervailing challenges of decreasing reservoir quality and the requirement for new methods to meet both economic and environmental goals. Ongoing, consistent funding of research and development is required. Yet if history repeats itself, the industry will continue to make strides—potentially significant ones—toward increasing resource frugality. The seeds have already been planted in a plethora of new extraction processes being deployed at the pilot scale level. The potential for the future is a lower environmental footprint per barrel extracted.

## REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Calgary (August 10, 2010) that provided an opportunity for oil sands stakeholders to discuss perspectives on the key issues related to oil sands technology. 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 Oil Sands Trust

Cenovus Energy Inc.

ConocoPhillips Company

Deborah Yedlin, Calgary Herald

Devon Energy Corporation

Energy and Environmental Solutions, Alberta Innovates

Energy Resources Conservation Board (Alberta)—ERCB

General Electric Company—GE

Imperial Oil Ltd.

In Situ Oil Sands Alliance—IOSA

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Pembina Institute

Petroleum Technology Alliance of Canada (PTAC)

Shell Canada

SilverBirch Energy Corporation

Statoil Canada Ltd.

Strategy West

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

University of Alberta

US Department of Energy

## IHS CERA TEAM

**David Hobbs,** Chief Energy Strategist

David Hobbs, IHS CERA Chief Energy Strategist, is an expert in energy industry structure and strategies. He previously managed IHS CERA's energy research activities. Mr. Hobbs is a principal author of the major IHS CERA studies *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda,* a comprehensive examination of the impact of the changed natural gas supply outlook on energy markets, power generation technology choices, and the challenges in achieving a low-carbon future; *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures* and *Modernizing Oil and Gas Disclosures,* comprehensive analyses of the problem of assessing oil and gas reserves and resulting proposed solutions; *"Recession Shock": The Impact of the Economic and Financial Crisis on the Oil Market,* a major IHS CERA assessment of the world economic crisis; and the IHS CERA Multiclient Study *Harnessing the Storm—Investment Challenges and the Future of the Oil Value Chain.* He was a project advisor to the IHS CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.*

Mr. Hobbs is IHS CERA's representative on the management board of the Global Energy Executive MBA program run jointly by the Haskayne School of Business and IHS CERA. He is also a member of the Scientific Advisory Board of the Fondazione Eni Enrico Mattei. Prior to joining IHS CERA Mr. Hobbs had two decades of experience in the international exploration and production business. He has directed projects in Asia, South America, North America, and the North Sea and has led major international investment and asset commercialization operations. Based in Cambridge, Massachusetts, Mr. Hobbs holds a degree from Imperial College.

**James Burkhard,** Managing Director

James Burkhard, Managing Director of IHS CERA's Global Oil Group, leads the team of IHS CERA experts that analyze and assess upstream and downstream market conditions and changes in the oil and gas industry's competitive environment. A foundation of this work is detailed short- and long-term outlooks for global crude oil and refined products markets that are integrated with outlooks for other energy sources, economic growth, geopolitics, and security. Mr. Burkhard's expertise covers geopolitics, industry dynamics, and global oil demand and supply trends.

Mr. Burkhard also leads the IHS CERA Global Energy Scenarios effort, which combines energy, economic, and security expertise across the IHS Insight businesses into a comprehensive, scenario-based framework for assessing and projecting global and regional energy market and industry dynamics. Previously he led the IHS CERA study *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030,* which encompassed the oil, gas, and electricity sectors. He was also the director of the IHS CERA Multiclient Study *Potential versus Reality: West African Oil and Gas to 2020.* He is the coauthor of IHS CERA's respected *World Oil Watch,* which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Before joining IHS CERA Mr. Burkhard was a member of the United States Peace Corps in Niger, West Africa. He directed infrastructure projects to improve water availability and credit facilities. He was also a field operator for Rod Electric. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

**Jackie Forrest,** Director

Jackie Forrest, IHS CERA Director, Global Oil, leads the research effort for the IHS CERA *Oil Sands Energy Dialogue*. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products. She actively monitors emerging strategic trends related to oil sands, including capital projects, economics, policy, environment, and markets. She is the author of several IHS CERA Private Reports, including an investigation of US heavy crude supply and 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. 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. 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. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**Roger J. Goodman,** Senior Consultant

Roger J. Goodman, IHS CERA Senior Consultant, is an authority on natural gas, coal, and electricity market trends. He specializes in strategy, scenario planning, technology, marketing, and business development. For nearly 15 years Dr. Goodman was employed in a variety of senior management positions with Shell Canada Limited in strategic and scenario planning, business development, and marketing, especially in natural gas, electricity, sulfur, and liquids. Prior to his career at Shell he was employed at Crows Nest Resources Limited as Manager, International Coal Marketing, responsible for markets in North America, Europe, and Africa. He has also held senior management positions in the Canadian government in the areas of trade promotion, metals, minerals, and energy specialist and headed Canadian delegations as a technical expert at international meetings of United Nations Conference on Trade and Development, United Nations Industrial Development Organization, and the OECD. He is a founder and President of Kernow Enterprises Inc., a consultancy practice specializing in business trends and strategic and scenario analysis. Dr. Goodman is the author of several IHS CERA reports, including analyses of coal commoditization; power generation; fuel cells; hydrogen; Canada's Kyoto compliance strategies; and Canada's electric power and fuels sectors including nuclear, hydro, natural gas, and coalbed methane. Dr. Goodman holds a BA from Carleton University, a BSc (Honors) from the University of Wales in Cardiff, and a DPhil from Oxford.

**Judson Jacobs,** Director

Judson Jacobs, IHS CERA Director, is a Research Director in IHS CERA's Upstream Technology practice. In this role he studies the strategic implications of digital and oilfield technologies in the exploration and production (E&P) sector. He was the primary contributor to IHS CERA's *Digital Oil Field of the Future* (DOFF) Multiclient Study and continues to examine technology issues related to production activities in leading IHS CERA's DOFF Forum service. Other recent research includes information technology externalization in E&P, the expanding role of seismic, and industry knowledge management trends. Prior to joining IHS CERA Mr. Jacobs worked at the Mitchell Madison Group, a strategy consulting firm, where he served the energy and financial services sectors. His background in the upstream oil and gas industry includes engineering positions with Schlumberger Wireline Services and work as an exploration geologist in Anadarko Petroleum Corporation's international division. Mr. Jacobs hold a BSE from Princeton University and an MS in Geology from Stanford University.

# Pipelines, Prices, and Promises

The story of western Canadian market access

April 2017

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Canadian Oil Sands Dialogue | **Strategic Report**

# Contents

# Pipelines, Prices, and Promises

## The story of western Canadian market access

### About this report

**Purpose.** Since 2009, IHS Markit has made public research on issues surrounding the development of the Canadian oil sands. As western Canadian production has increased, it has at times overtaken available pipeline takeaway capacity, reducing the price that producers have been able to obtain for their crude oil. Pipeline projects have been proposed to move increasing volumes to market, but they have also met opposition and ultimately delay. This report explores the status of western Canadian pipeline capacity, demand, and supply and the promise of advancing pipelines.

**Context.** This report is part of a series of reports from the IHS Markit Canadian Oil Sands 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.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

**Structure.** This report has three sections.

Part 1: Western Canada has become accustomed to price volatility

Part 2: A history of pipeline delay

Part 3: New pipeline capacity on the horizon, but growth of crude by rail also expected

# Pipelines, Prices, and Promises

## The story of western Canadian market access

**Kevin Birn,** Senior Director
**Karen Kuang,** Senior Analyst
**Patrick Smith,** Research Analyst

### Key implications

The history of pipeline proposals, particularly those from western Canada, has been tumultuous. Various pipeline projects have been proposed, approved, overturned, denied, and—more recently—revived. At times, pipeline capacity from western Canada has been constrained, and the price of oil in western Canada has fallen well below that of global peers. This report explores the relationship between pipelines and prices, the current state of pipeline proposals, and the outlook for this relationship. It focuses on what has become a top concern—the building of the infrastructure necessary to connect growing supply to markets.

- **Transportation cost is a key reason why oil prices differ among regions.** Although variations in quality, such as light versus heavy oil, result in price differences among various crude oils, transportation costs contribute to price differences among regions for crude of similar quality.
- **Transportation constraints have, in the past, contributed to price volatility and a loss of economic value for western Canadian producers.** Pipeline constraints have contributed to price volatility for western Canadian producers and a rise of crude by rail. At times, price discounts were severe, which incentivized investments in new pipeline takeaway capacity from western Canada.
- **The average pipeline review process, from application to early 2017, has spanned more than five years, with no major additions constructed in recent years.** The processes have spanned more than eight years for the Keystone XL pipeline; more than six years for Northern Gateway; more than four years for the Alberta Clipper Expansion; more than three years for the Trans Mountain Expansion; and two years for Energy East, which is still in the early days. This does not include the time prior to application for business development and for front-end engineering and design.
- **Western Canada has the potential to move from a pipeline capacity shortfall to surplus.** If all pipelines advance as announced, nearly 2.9 MMb/d of new takeaway capacity could be added—sufficient to meet growing Canadian supply for some time.
- **Although there is a new sense of pipeline optimism, none of the proposed projects are done deals.** Pipeline projects remain controversial and will likely face ongoing challenges from opposition and litigation.

## Western Canada has become accustomed to price volatility

Western Canadian oil producers are landlocked, with nearly all exports sold to the United States via long-distance overland pipelines. With output destined to rise over the next few years, building pipelines—the infrastructure required to connect supplies with buyers—is of the utmost importance for western Canada.

Prices in western Canada track global markets but at a price that reflects the cost of transport to the greatest source of demand. This has historically been via pipeline to the US Midwest. When transportation has been functioning efficiently and without constraints, western Canadian heavy oil has tracked within roughly $8/bbl of globally traded crudes of similar quality, such as Mexican Maya.[1] For more information on the factors that contribute to price differences among regions, please see the box "Primer: Oil price differences among regions."

However, the price of crude oil in western Canada has, for some periods, been discounted much more dramatically than globally traded crudes. In the past, transportation system bottlenecks have occurred, causing crude oil to become trapped until it could clear the market through higher-cost forms of transport.

For example, during a five-month period from November 2012 through March 2013, WCS obtained approximately $30/bbl less than Mexican Maya (see Figure 1). During this period, western Canadian heavy oil production averaged nearly 1.7 MMb/d, which would equate to about $6 billion in lost revenue over just this period.[2] As Figure 1 shows, in recent years there have been multiple periods of reduced prices.

### Primer: Oil price differences among regions

The price of crude oil—a globally traded commodity—tracks from region to region. However, price differences among regions do exist. This has been an area of particular interest in western Canada, where oil prices are lower than those of globally traded peers. There are two often cited reasons why oil prices may differ between regions: transportation and crude quality. However, only transportation results in price differences for similar quality crudes between regions.

**Transportation.** Transportation connects oil-producing regions to consumers. The cost of transport, which can vary by distance and/or mode, can result in price differences for crude oil of similar quality between regions. For example, prior to the rise of inland US crude oil production, Canadian light crude competed for market share in the Chicago area with light crude oil from the US Gulf Coast region. From 2006 to 2010, before US tight oil changed inland relationships, the cost of western Canadian light crude oil in the Chicago area priced within $2–3 of similar crude from the US Gulf Coast despite the 2,300 miles between these two producing regions.*

**Quality.** Another reason for oil price differences is crude quality. Although in principle substitutable, crude oil is not homogenous. Crude quality is often distinguished by density, viscosity, and impurities. In a general sense, less dense, or "lighter," crude oils are more easily converted into refined products such as gasoline and diesel. "Heavier," or higher-density, crudes are more costly to convert into refined products. Impurities, such as sulfur, must be removed during the refining process to meet product specifications. The greater the sulfur level (and/or other impurities), the higher the cost to process the crude oil. Low-sulfur crudes (less than 1%) are called "sweet," while high-sulfur crudes are "sour." Sulfur is the most commonly cited impurity, but others, such as heavy metals or acids, also exist. Generally, the heavier and more sour the crude, the more energy that is required for refining and the lower the value refiners will place on the crude. For example, Mixed Sweet Blend (MSW) and Western Canadian Select (WCS) are two crude oils from Alberta, but they differ in quality. WCS is categorized as a "heavy, sour" crude whereas MSW is a "light, sweet" crude. In 2016, WCS averaged roughly $30/bbl while MSW averaged $41/bbl.

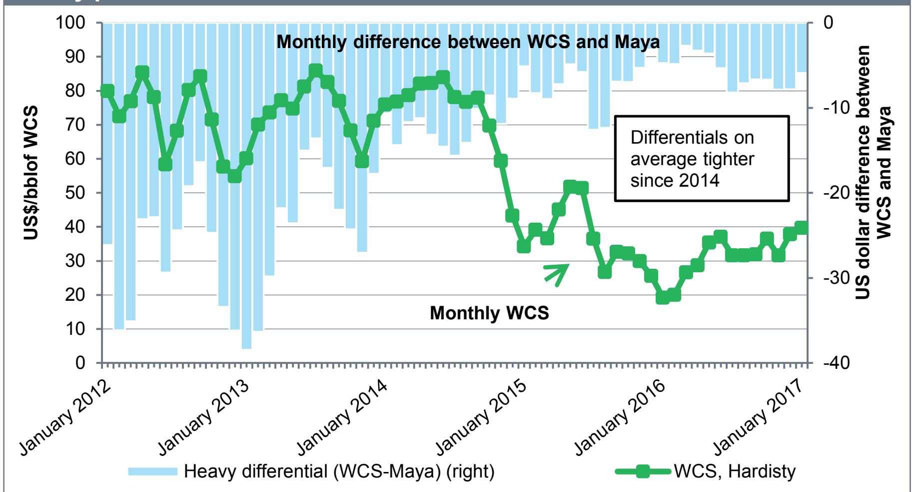
*The cost of Louisiana Light Sweet (LLS), a light crude oil benchmark price indicator on the US Gulf Coast, averaged about $78/bbl from 2006 to 2010, with the average pipeline transportation cost into the Chicago area at about $1/bbl. By comparison, MSW, a light crude oil benchmark priced in Alberta of similar but not identical quality to LLS, averaged about $74/bbl over the same period, with the cost of transport to the Chicago region averaging nearly $3/bbl.

1. The estimate is based on the average range adjusted for periods with extreme outliers during 2006–16 between Western Canadian Select (WCS), a heavy crude oil benchmark in western Canada, and Mexican Maya, a globally traded heavy crude oil benchmark for the US Gulf Coast.

2. This production includes conventional and heavy bitumen blend from 1 November 2012 to 31 March 2013, adjusted for transportation cost to the US Gulf Coast region.

Figure 1

Western Canada heavy crude benchmark price and differential to global heavy prices




Source: Argus, IHS Markit

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As production growth accelerated in western Canada, a number of pipelines were proposed to resolve anticipated transportation constraints. Some of these projects have been under various stages of review since 2008. In the absence of new pipeline infrastructure, western Canada experienced increased price volatility and around 2012 producers began to turn to railroads for their product to reach market.

## Rail has proven capable of moving significant volumes

At its peak in late 2014, the North American crude-by-rail business topped 1.2 MMb/d of movements. Nearly four-fifths of these movements—or 1 MMb/d—originated in the United States, with the largest source coming from US tight oil in North Dakota. Western Canadian movements also reached a historical high in the same period, at more than 230,000 b/d. The cost of transporting crude oil by rail has historically been higher than pipe, reducing the price of crude oil in western Canada relative to other crudes of similar quality.

## In recent years, western Canadian price differentials have narrowed

Since the price collapse of 2014–15, crude-by-rail movements have subsided, and the price difference between western Canadian heavy crude oil and globally traded crudes has diminished. There are several reasons why this has occurred:

**Conventional production declines.** From the end of 2014 to the end of 2016, conventional oil production in western Canada declined nearly 300,000 b/d. Lower oil prices reduced upstream investment, leading to a drop in conventional oil supply. This helped ease pressure on the pipeline system for rising heavy oil sands supply, which increased more than 360,000 b/d over the same period.[3]

**Pipeline throughput increased.** Although no new long-distance pipeline has been completed in recent years, pipeline operators have been able to increase throughput by making better use of their existing permits as well as using drag-reducing agents that can increase the flow of crude oil. For example, Enbridge was able to achieve higher export capacity on its Canadian mainline system by making use of an underutilized segment with an existing cross-border permit.[4]

Western Canadian volumes continue to build, and the pipeline system is expected to become increasingly constrained. Toward the end of 2016, US crude oil imports from Canada exceeded 3.5 MMb/d—the highest on record to date.[5] Moreover, the decline of western Canadian conventional production—which has helped offset rising heavy supply—is anticipated to slow in 2017. Western Canada supply (inclusive of imported diluents used in oil sands bitumen blends)

3. Conventional oil includes both light and heavy western Canadian production. Oil sands includes synthetic crude oil and bitumen blends. Estimate is based on the last three months of 2014 compared with the last two months of available data for 2016 (October to November) at the time of this report completion.

4. Alberta Clipper was brought online in 2010 with a permit to export 450,000 b/d, but design capacity since then has expanded and is capable of greater throughput. Enbridge Line 3 went into service in 1968. Since 2010, Line 3 had been operating at reduced pressure, which decreased throughput to 390,000 b/d, down from the initial export permit capacity of 760,000 b/d. In 2014, interconnections between Line 67 and Line 3 allowed Enbridge to make use of Line 3's cross-border permit capacity while maintaining lower pressure on Line 3. Enbridge has since undertaken the replacement of Line 3, which will allow it to return Line 3 to historical capacity of 760,000 b/d. However, once the Line 3 replacement is complete, Line 67 will require an amendment to its existing presidential permit to take full advantage of the expanded capacity.

5. Source: US Energy Information Administration.

could reach 4.8 MMb/d by 2020, an increase of nearly 1 million b/d from 2016 levels. In the absence of new pipeline takeaway capacity, the system will become increasingly constrained and a resurgence of crude by rail seems likely.

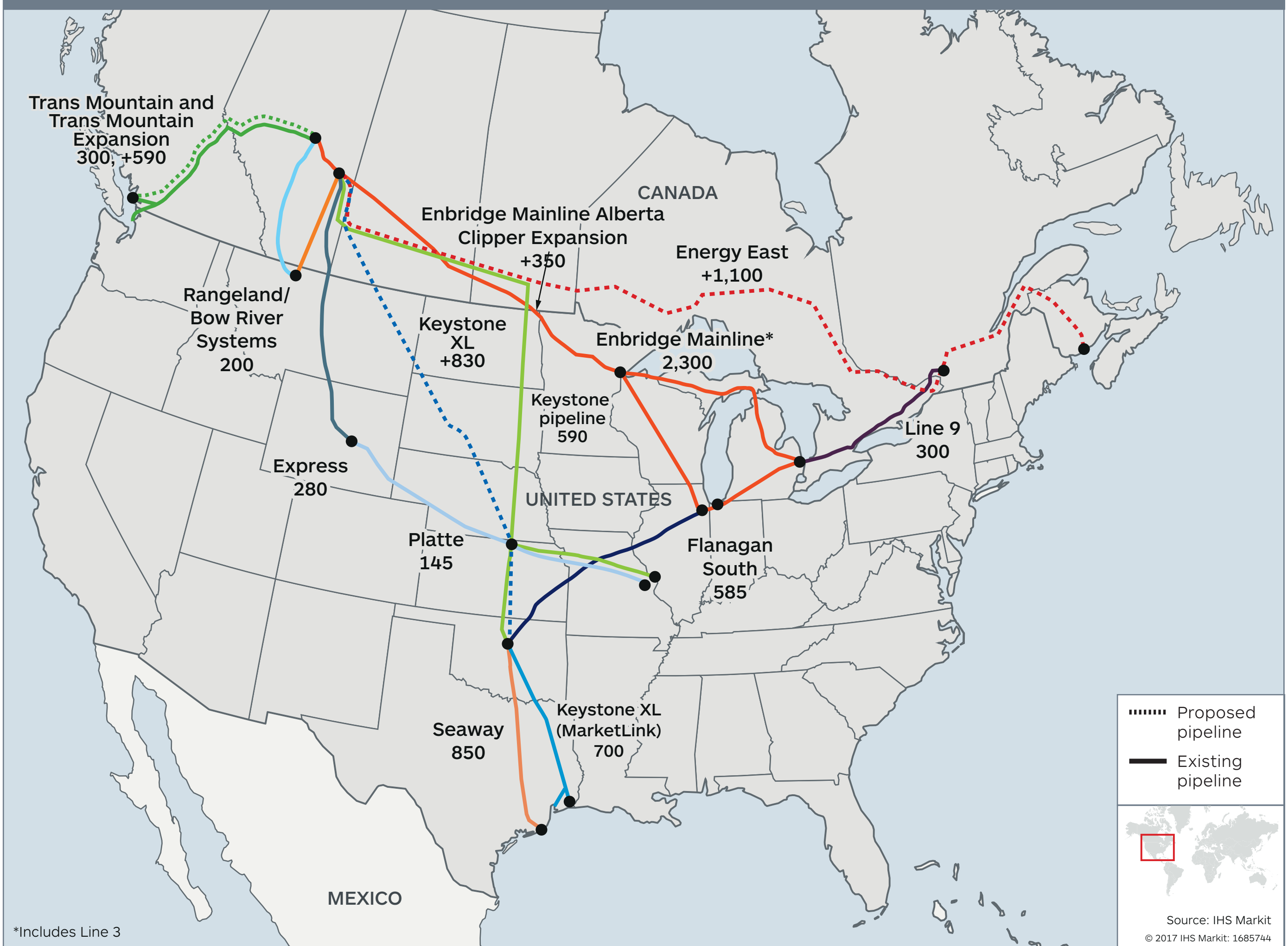
## A history of pipeline delay

Several pipelines have been proposed to help resolve western Canada's pipeline constraints (see Figure 2 and Table 1). In total, nearly 2.9 MMb/d of new capacity has been proposed. Keystone XL and the Enbridge Mainline expansion would head south to the United States. The Trans Mountain Expansion would head west to Canada's coast for export into the Pacific Basin. Energy East would take western Canadian production to eastern markets and offshore. Northern Gateway was also proposed to move crude oil west, but the Canadian government denied it the necessary permit in late 2016.

Differences of opinion about the need for new pipeline infrastructure and the potential environmental and climate impacts have turned proposed pipeline projects that were once largely unknown to the public into household names and made them politically sensitive. Although it is generally agreed these factors have affected the timing of major pipeline projects, the degree and types of delay vary across projects and are not well understood.

Figure 2

**Existing and proposed pipelines departing western Canada (thousand b/d)**



## Measuring pipeline delay

Major infrastructure projects seldom proceed as planned. This has proven true for Canadian pipeline projects that span thousands of miles and take multiple years to complete. For pipelines proposed to depart western Canada, the time between applications and decisions has, for some, been extensive. Since 2010, when the Alberta Clipper and the first Keystone pipeline were commissioned, no new long-distance pipeline project departing western Canada has been successfully completed.

Table 1

**Pipeline descriptions**

| Destination | Pipeline project (proponent) | Route | Incremental capacity (b/d) | Status |
|---|---|---|---|---|
| US markets | Line 67 "Alberta Clipper" Expansion (Enbridge) | Hardisty, Alberta, to Superior, Wisconsin | 350,000 | Pending presidential permit |
| | Keystone XL (TransCanada) | Hardisty, Alberta, to US Gulf Coast region | 830,000 | Presidential permit issued, route under review by Nebraska |
| Eastern Canada and East Coast offshore | Energy East (TransCanada) | Hardisty, Alberta, to tidewater in Saint John, New Brunswick | 1,100,000 | Under regulatory review |
| West Coast offshore | Northern Gateway (Enbridge) | Bruderheim, Alberta, to Kitimat, British Columbia | 525,000 | Denied |
| | Trans Mountain Expansion (Kinder Morgan) | Edmonton, Alberta, to tidewater in Burnaby, British Columbia | 590,000 | Permitted |

Source: Various sources, company releases, IHS Markit © 2017 IHS Markit

Pipeline projects are subject to an extensive review process (in Canada and the United States). These reviews explore the technical, economic, and environmental merits of the projects and seek ways to maximize economic value while mitigating potentially adverse environmental impacts. They aim to engage various stakeholders, including the Indigenous peoples, local communities, and others, to identify interests or concerns associated with a project. Because each pipeline project is unique, the review periods have varied, but they have always spanned multiple years. Upon completion of the review process, regulators are required to make a recommendation to the government. This can include subjecting the project to any number of conditions. Examples of conditions that can be included are when and where construction may occur, what material may be used in construction, what additional safety measures or offsets for disturbed land may be required, and how the pipeline may be operated.

Once the reviewing agencies have made their recommendation, the decision falls to the government. In the case of the United States, the State Department is both the adjudicator (lead reviewer) and the decision maker in issuing a presidential permit.[6] However, should differences of opinion arise during the State Department review, the president can become involved. The State Department involvement in pipelines pertains to permitting international border crossings. Multiple federal agencies are involved in reviewing and regulating interstate pipelines in the United States. Individual states also play a major role in permitting oil pipelines through their territories. In Canada, although provinces may become involved, the federal government has jurisdiction over projects transcending provincial and national boundaries. In Canada, the National Energy Board (NEB) acts as both project adjudicator and regulator, with the federal cabinet being the final decision maker on major projects.

The political decision-making process can be opaque. The high degree of public interest in pipeline projects also makes the final decision particularly sensitive for governments. Keystone XL, for example, was denied twice during President Barack Obama's administration after it received approval from Canada's NEB, only to have President Donald J. Trump invite TransCanada Corporation to reapply and then ultimately approve a cross-border permit.[7]

6. The authority to authorize cross-border permits is derived from the US Constitution, which provides the president with the responsibility for protecting the territorial sovereignty of the United States. In 1968, the president issued an executive order delegating the authority to issue border permits to the secretary of state. For more information, see the "Interpretative Guidance on Executive Order 11423," US Department of State, retrieved 1 April 2017.

7. In 2012, the State Department recommended that there was inadequate basis to make a decision given the time allotted by the US Congress. Later in 2015, the State Department did not approve the permit on the grounds that it was inconsistent with wider climate change objectives. On 24 January 2017, President Trump invited TransCanada to reapply. See the 18 January 2012 "Statement by the President on the Keystone XL Pipeline," Obama White House Archives, retrieved 22 March 2017; the 6 November 2015 "Statement by the President on the Keystone XL Pipeline," Obama White House Archives, retrieved 22 March 2017; and the "Presidential Memorandum Regarding Construction of the Keystone XL Pipeline," The White House, retrieved 30 March 2017.

Given that pipelines have failed to materialize along announced timelines, concern has been expressed that the review process has become increasingly uncertain, contentious, lengthy, and, as a result, costly. When IHS Markit examined the history of past pipeline review processes—from application to permit (and beyond)—we found that older pipeline projects (or pipelines that started earlier in the regulatory process) have indeed faced longer processes. We found insufficient evidence to conclude that there has been a material difference in time between processes involving a US presidential permit or those solely within Canada. The single-greatest source of uncertainty or lengthiest part of the process in recent years has come after regulators have made their recommendations and when elected officials needed to decide. Yet, the story on these pipelines is not over, since none have been completed and the potential for additional delay exists.

Figure 3 depicts the results of our review of timelines for the major western Canadian export-bound pipeline proposals. It is important to note that a number of factors can affect the review process. This figure captures only the key events and the timelines associated with major proposed pipeline projects departing western Canada. This summary includes Canadian federal regulatory review processes as administered by the NEB and the Government of Canada as well as the US presidential review process for pipelines transiting south to the United States. Not shown in this figure are additional regulatory processes that may be required, such as those conducted by the Federal Energy Regulatory Commission for major US pipelines and the state-level processes.

### The process does not end with a permit

A permit does not mean the end of the process. Between permitting, construction, and ultimately operation, many additional factors can affect project completion. These can include adhering to any number of conditions imposed by government, addressing public interests and interests of particular groups, and responding to requests for judicial review.

Permits are not a blank check. They are subject to oversight and typically come with a number of conditions. These conditions are put in place by regulators and the government to try to address, as best as possible, environmental, social, and economic concerns that may arise during the review process. The number of conditions can climb into the hundreds and affect the pipeline over its entire life, from construction to abandonment. For example, the Trans Mountain Expansion project approval was subject to 157 conditions.[8]

The courts also have a say in pipeline projects. In Canada, in addition to typical challenges to government decisions, such as pointing out shortcomings or mistakes in a process, First Nations have an additional right or special relationship with the government in which they are owed a duty to be consulted on decisions that may affect them. In the past, failure by the government to adequately consult has led to project delays, route changes, and even the loss of permits. This was the outcome of a challenge to the Northern Gateway project.

More recently, acts of civil disobedience have influenced the timing of pipelines. In North Dakota, demonstrators successfully slowed the construction of the Dakota Access Pipeline (DAPL) (the last 1,000 feet of the pipeline across the Missouri River/Lake Oahe, specifically) by raising the profile of their concerns sufficiently to get the government to delay the project.9 Although the example of DAPL was recently overturned by President Trump, the demonstrations nevertheless impeded the completion of the project for a period.

Even if a project successfully moves into operation, regulators and proponents have ongoing commitments that will span the life of the project. Regulators have an obligation to monitor the project to ensure compliance with conditions and required operating procedures. Operators have obligations to consult and work with communities along project routes over the project's life.

## New pipeline capacity on the horizon, but growth of crude by rail also expected

A cautious sense of optimism may be taking hold in western Canada as oil prices gradually recover and as the prospects of new pipelines seem to be tipping in producers' favor. The Trans Mountain Expansion received permits from the

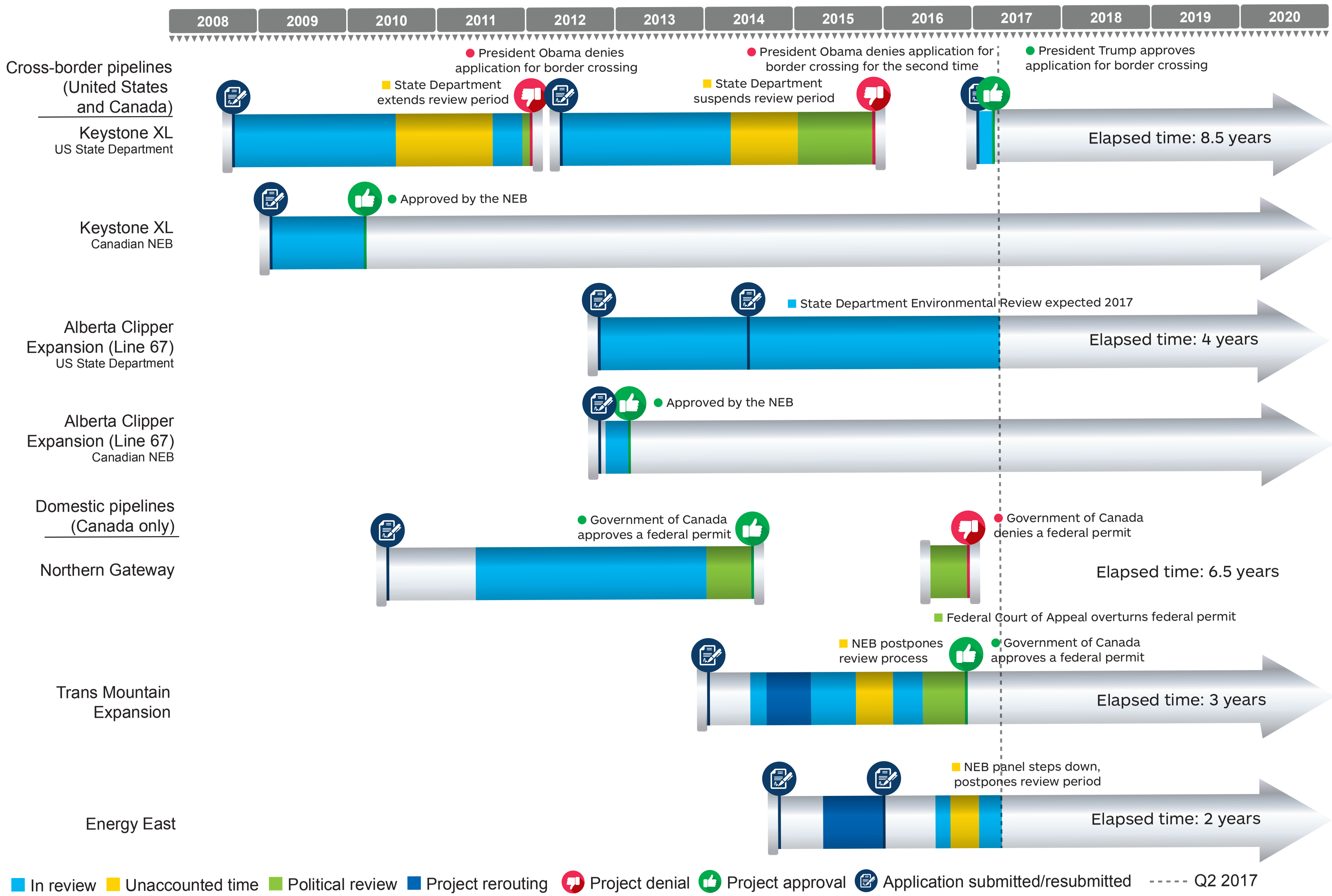
8. See the "National Energy Board Report—Trans Mountain Expansion Project," Appendix 3, retrieved 5 April 2017.

9. The DAPL is a $3.8 billion, 1,172-mile pipeline that would connect North Dakota tight oil production from the Bakken region to inland US refining markets.

Figure 3

## Historical review of the timing of major western Canadian export pipelines proposals




Note: This figure illustrates the timelines of major Canadian export pipelines. Image is not to scale. Numerous sources were used in the making of this figure. There are three pipeline projects that fit wholly within the federal government of Canada review processes and two that would cross international boundaries into the United States and require review by the US State Department and a presidential permit to construct a new border crossing. Additional federal, provincial, and state processes may also be triggered by these projects but were not included for brevity. Time can occur between applications to the Canadian federal review process until the issuance of a hearing order, which marks the commencement of a formal review process. Estimate of total elapsed time is based on time of first application to the beginning of 2017.

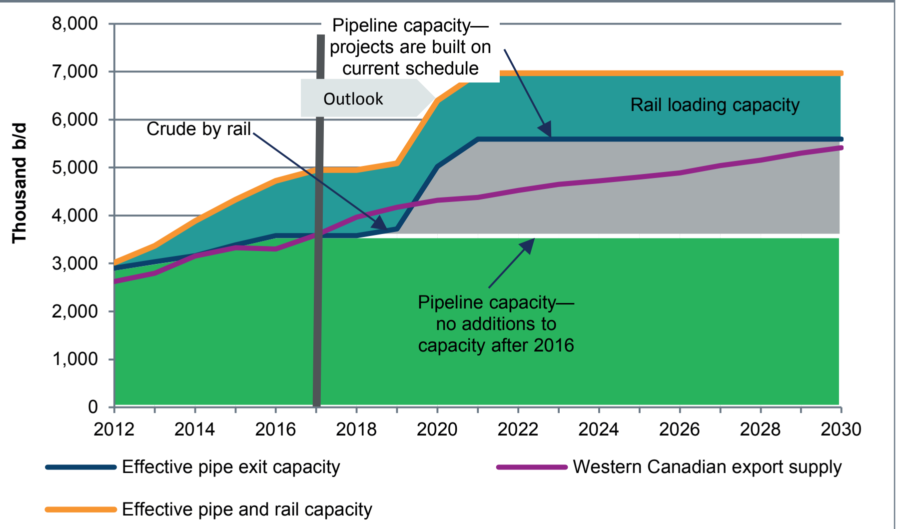
Sources: NEB, US Department of State, US Congress, Obama White House Archives, The White House, Nebraska Supreme Court, Prime Minister of Canada, Canadian Federal Court of Appeal

Government of Canada on 29 November 2016, with the Province of British Columbia agreeing not to oppose the pipeline early in 2017.[10] Keystone XL, which was denied a cross-border permit in 2015, received a presidential permit on 24 March 2017 after President Trump invited TransCanada to resubmit an application in early January.[11] The US State Department recently completed a draft of the Supplementary Environmental Impact Statement for the Alberta Clipper (also known as Line 67) Expansion, which will likely advance toward the US president in late 2017 for permission to expand the existing cross-border permit. The Energy East project is the earliest in the process, having reentered the formal hearing process at the NEB in January 2017.

If all four pipeline projects advance as currently proposed, western Canadian pipeline takeaway capacity could move from one of shortage to surplus (see Figure 4). In total, these projects could add nearly 2.9 MMb/d of new pipeline capacity in 2019–22.[12] Pipelines do not operate at 100% of capacity, and not all of this capacity would be exclusive to western Canadian oil producers. Some US production would likely also make use of the south- and eastbound systems. Pipelines also can have different commercial arrangements—some are backed with firm commitments by producers to take or pay for a fixed contracted volume over a specified period, while other pipelines may have spot agreements. However, if completed, these additions could be sufficient to meet growing Canadian supply for some time—removing a cloud of uncertainty that has faced western Canadian producers.

Figure 4

Western Canadian supply for export versus effective pipeline capacity




Source: IHS Markit



Each pipeline offers producers different benefits. Southbound pipelines would strengthen Canadian-US energy integration and US energy security. Others heading to the coasts (east or west) would provide Canadian production an opportunity to access global markets and diversify away from dependence on a single market (the United States). Although the United States (the Gulf Coast in particular) remains the most likely market for growing Canadian heavy supply owing to the region's preexisting refinery capacity capable of processing heavier crudes, lessons from the timing of Keystone XL and concerns about a possible resurgence of US protectionism have highlighted the importance of market diversification. In 2016, 99% of Canadian crude oil exports went south to the US market.

For the time being, however, none of these proposed pipelines change the likelihood that a resurgence of crude by rail out of western Canada is expected through the end of the decade. With the earliest of any proposed pipelines potentially online in 2019, western Canadian supply growth seems destined to overtake available capacity, and increasing movements of crude by rail are expected—and with that prices should decline. Although IHS Markit anticipates greater price discounts, they should be more modest than in the past, as years of investments in crude-by-rail infrastructure, such as loading terminals and railcars, are expected to pay off. The timing and scale of the future movements will depend

10. See the Government of Canada's news release "Government of Canada announces pipeline plan that will protect the environment and grow the economy," retrieved 22 March 2017, and the Province of British Columbia's news release "Five conditions secure coastal protection and economic benefits for all British Columbians," retrieved 22 March 2017.

11. On 24 January 2017, President Trump invited TransCanada to reapply, promising an expedited, 60-day review. The application was submitted by TransCanada on 26 January 2017. The US State Department issued its decision on 24 March 2017, with the president indicating that the pipeline would receive a permit. Source: "Presidential Memorandum Regarding Construction of Keystone XL Pipeline," The White House, retrieved 5 April 2017, and "President Trump Delivers on Jobs for American People," The White House, retrieved 5 April 2017.

12. This figure includes Keystone XL, the Trans Mountain Expansion, the Alberta Clipper Expansion, and Energy East.

on the rate of supply additions over the next year, including when conventional supply begins to expand again and the ability of pipeline companies to continue to optimize their systems. It should be noted that even in the event that pipeline capacity expands, some volumes of crude-by-rail are expected to persist as rail can provide additional optionality for producers.

Despite the optimism, there is no guarantee that these projects and other expansions will advance as proposed. These projects remain controversial and may face additional challenges. Within weeks of the federal permit being issued, it was reported that at least eight requests for judicial review had already been filed against the Trans Mountain Expansion—a plan to twin an existing line.[13] Although Keystone XL is now permitted, it will likely face legal challenges and still require state-level approvals, which may yet complicate its completion. President Trump also has previously suggested that new pipelines could be subject to additional conditions; these conditions could affect both the Keystone XL and Alberta Clipper Expansion, which is still seeking its presidential permit. Only time will tell whether the pipelines continue to meet delay or if the necessity of new infrastructure for western Canadian oil producers is realized.

13. See "Environmentalists file court challenge of Ottawa's Trans Mountain pipeline approval," CBC News, retrieved 5 April 2017.

## IHS Markit team

**Kevin Birn,** Senior Director, IHS Markit, is part of the North American Crude Oil Markets team and leads the Oil Sands Dialogue. His expertise includes energy and climate policy, project economics, transportation logistics, and oil market fundamentals. His recent research includes analysis of the greenhouse gas intensity of oil sands, economic benefits of oil sands development, upgrading economics, oil sands competitiveness, and implications of advancing climate policy. To date, Mr. Birn has authored or coauthored 30 reports associated with development of the Canadian oil sands. Prior to joining IHS Markit, Mr. Birn worked for the Government of Canada as the senior oil sands economist at Natural Resources Canada. He has contributed to numerous government and international collaborative research efforts, including the 2011 National Petroleum Council report “Prudent Development of Natural Gas & Oil Resources” for the US secretary of energy. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta.

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# The Role of the Canadian Oil Sands in the US Market

## Energy Security, Changing Supply Trends, and the Keystone XL Pipeline

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# THE ROLE OF THE CANADIAN OIL SANDS IN THE US MARKET: ENERGY SECURITY, CHANGING SUPPLY TRENDS, AND THE KEYSTONE XL PIPELINE

## EXECUTIVE SUMMARY

A key uncertainty about the future role of the Canadian oil sands is whether the US government will allow production from Canada to expand its reach into the United States. The US Department of State (DOS) is reviewing the application by TransCanada to build a pipeline from Alberta, Canada, to the US Gulf Coast. For the Keystone XL pipeline review, the DOS commissioned studies to evaluate US market dynamics and life-cycle greenhouse gas (GHG) emissions as part of the Supplemental Draft Environmental Impact Statement (SDEIS) released for comment in April 2011. This IHS CERA Special Report identifies and explains differences between the SDEIS and IHS CERA analyses on three critical questions:

- **When is the new pipeline infrastructure required, and could this pipeline affect gasoline prices?** By 2015 oil sands exports will likely exceed refining capacity in the US Midwest—currently the main market for oil sands output. Keystone XL will increase supply to the broader US market—namely the US Gulf Coast. For a given level of demand, higher supply would lower prices for crude oil, which is the most important factor shaping gasoline prices.

- **What are the likely substitutes for oil sands crudes if Keystone XL is not approved?** The US Gulf Coast is the world's most sophisticated refining region. In the absence of oil sands supply, Gulf Coast refiners are expected to demand similar volumes of heavy crude oils, but from more distant sources of supply.

- **What are the incremental GHG emissions associated with consuming oil sands?** The increase in GHG emissions from oil sands, and consequently from the proposed pipeline, is not as high as is often perceived. On a life-cycle basis, GHG intensity of the average oil sands import is about 6 percent higher than that of the average crude oil consumed in the United States.

—June 2011

**About IHS CERA**



IHS CERA

# THE ROLE OF THE CANADIAN OIL SANDS IN THE US MARKET: ENERGY SECURITY, CHANGING SUPPLY TRENDS, AND THE KEYSTONE XL PIPELINE

## INTRODUCTION

High oil prices during a time of potentially momentous change in North Africa and the Middle East and rising demand from emerging markets are raising concerns about availability of oil and about future price trends. In the realm of US energy security, one of the biggest achievements of the past decade has been the growing use of Canadian oil sands production to supply the US market. Oil sands production has made Canada the number one supplier by far of foreign oil to the United States.

In 2010 the United States imported about 2 million barrels per day (mbd) of oil from Canada, or 22 percent of total imports. About 1.1 mbd of Canada's crude oil exports were from the oil sands of Alberta—a mega-resource right next door to the United States and connected by land-based pipelines. Oil sands matched the total US imports from Mexico, the number two foreign supplier, and in 2011 are poised to become the single largest source.

Canadian oil sands could play a steadily growing, long-term role in supplying the US market for many years to come. However, US pipeline infrastructure needs to catch up with changing supply trends and expanding supply—namely, rising output from Canada, as well as the rapidly growing output from the Bakken Formation in North Dakota and Montana. Currently Canadian and Bakken oil production is bottled up in the US Midwest, a regional market that is nearing saturation. Inadequate pipeline infrastructure could limit US access to rising Canadian and Bakken supply.[1]

The proposed 700,000 barrel per day (bd) Keystone XL pipeline would provide the first large-scale pipeline connection between Canada and the US Gulf Coast. Such an expansion would foster higher production and greater use of North American oil in the US market. Economic logic dictates that more supply results in lower prices for a given level of demand. A more dynamic and flexible pipeline system that boosts continental oil supply would be a big positive for American consumers and US energy security.

The US pipeline system was constructed in previous decades to deliver crude to the US Midwest from the US Gulf Coast, not the other way around. The current lack of significant pipeline capacity to expand the market "reach" of Canadian and Bakken crude oil deprives the broader US market of oil that is nearby and available.

The oil sands are part of a larger, dense network of US trade and investment relations with Canada, the largest market for American goods. In 2010 US-Canada trade totaled $525 billion. Eight million American jobs depend on trade with Canada.[2] More than 20,000 American

1. In this report the US Midwest is defined as Petroleum Administration for Defense District 2 (PADD 2). The region comprises Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Oklahoma, Ohio, South Dakota, Tennessee, and Wisconsin. The US Gulf Coast is defined as PADD 3 and comprises Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.
2. Testimony by James Burkhard, Managing Director of IHS CERA, before the US House of Representatives Subcommittee on Energy and Power, in Washington, DC, on May 23, 2011.

**About This Report**

This Special Report, including the appendix, is a detailed supplement to testimony presented by James Burkhard, Managing Director, IHS CERA, on May 23, 2011, before the US House of Representatives Committee on Energy and Commerce Subcommittee on Energy and Power, in Washington, DC, and provides details on the analysis supporting the testimony.

jobs already depend on oil sands development, and this number could grow significantly if oil sands investment expands through initiatives such as the proposed $7 billion Keystone XL pipeline project, which is among the largest "shovel-ready" projects in the United States.[1] Failure to expand access to the US market for additional Canadian supply would risk damaging the overall US-Canada relationship and leave the United States more reliant on distant oil supplies.

## THE KEYSTONE XL PIPELINE DECISION

A key uncertainty about the future role of the Canadian oil sands is whether the US government will allow production from Canada to expand its reach into the United States. The US Department of State (DOS) is reviewing the application by TransCanada to build a pipeline from Alberta, Canada, to the US Gulf Coast. Since this pipeline, known as Keystone XL, would cross an international border, the US DOS will determine whether a "Presidential Permit" will be issued to allow the pipeline to be built across the border and will also lead the project's environmental review (see the box "Proposed Keystone XL Pipeline"). Keystone XL would enable shipment of more oil sands production to the United States and could also transport additional US-produced oil to US Gulf Coast refiners.

For the Keystone XL pipeline review, the DOS commissioned studies to evaluate US market dynamics and life-cycle greenhouse gas (GHG) emissions as part of the Supplemental Draft Environmental Impact Statement (SDEIS) released for comment in April 2011. This IHS CERA Special Report identifies and explains differences between the SDEIS and IHS CERA analyses on three critical questions:

- **Question One:** When is the new pipeline infrastructure required, and could this pipeline affect gasoline prices?
- **Question Two:** What are the likely substitutes for oil sands crudes if Keystone XL is not approved?
- **Question Three:** What are the incremental GHG emissions associated with consuming oil sands?

The appendix provides details on the methodology, calculations, and assumptions supporting the analysis.

1. Ibid.

**Proposed Keystone XL Pipeline**

The proposed Keystone XL crude oil pipeline would be 1,711 miles long (2,754 kilometers [km]), and 36 inches in diameter. It would begin at Hardisty, Alberta, and extend southeast through Saskatchewan, Montana, South Dakota, Nebraska, Kansas, and Oklahoma to the Texas coast (see Figure 1). The US portion of the pipeline would be 1,384 miles (2,227 km) long. It would incorporate a portion of the existing Keystone Pipeline through Nebraska and Kansas to serve markets at Cushing, Oklahoma, before continuing through Oklahoma to a delivery point near existing terminals in Nederland, Texas. The pipeline would initially transport 700,000 bd of crude oil (primarily oil sands crude), with the option to expand to 830,000 bd. Keystone XL would enable greater flows of oil sands to the United States and create the first significant pipeline link from the US Midwest to the US Gulf Coast, which is the largest refinery region in the world. In addition to shipping oil sands, the project could transport US domestic crude oil production. As much as 150,000 bd could be transported from Cushing to the Gulf Coast via the proposed Cushing Marketlink project, and the proposed Bakken Marketlink could move 100,000 bd of oil supply.

## QUESTION ONE: WHEN IS NEW PIPELINE INFRASTRUCTURE REQUIRED, AND COULD THIS PIPELINE AFFECT GASOLINE PRICES?

Today the United States is practically the only market for Canadian crude oil.[1] Although Canadian oil is exported to many US regions, the majority of exports, including oil sands, go to the US Midwest. With the two recent pipeline expansions from western Canada to the US Midwest commissioned in 2010 (Enbridge's Alberta Clipper at 450,000 bd and TransCanada's Keystone at 590,000 bd), new oil sands supply will be consumed in this region.

The increasing oil sands exports to the Midwest mean that refineries there will eventually (around 2015, in IHS CERA's outlook) no longer be able to process any additional oil sands crudes. This is because the capacity to refine oil sands in the US Midwest—a market facing flat to declining petroleum demand—will not keep pace with oil sands production growth. IHS CERA's view differs from the SDEIS (using a report by a third party). The SDEIS concludes that in the absence of the Keystone XL pipeline, oil sands production would not be affected until 2020. The conclusion is based on projections of when oil sands production will fill the current pipeline capacity. In contrast IHS CERA finds that refinery capacity—not pipeline size—is the crucial constraint.

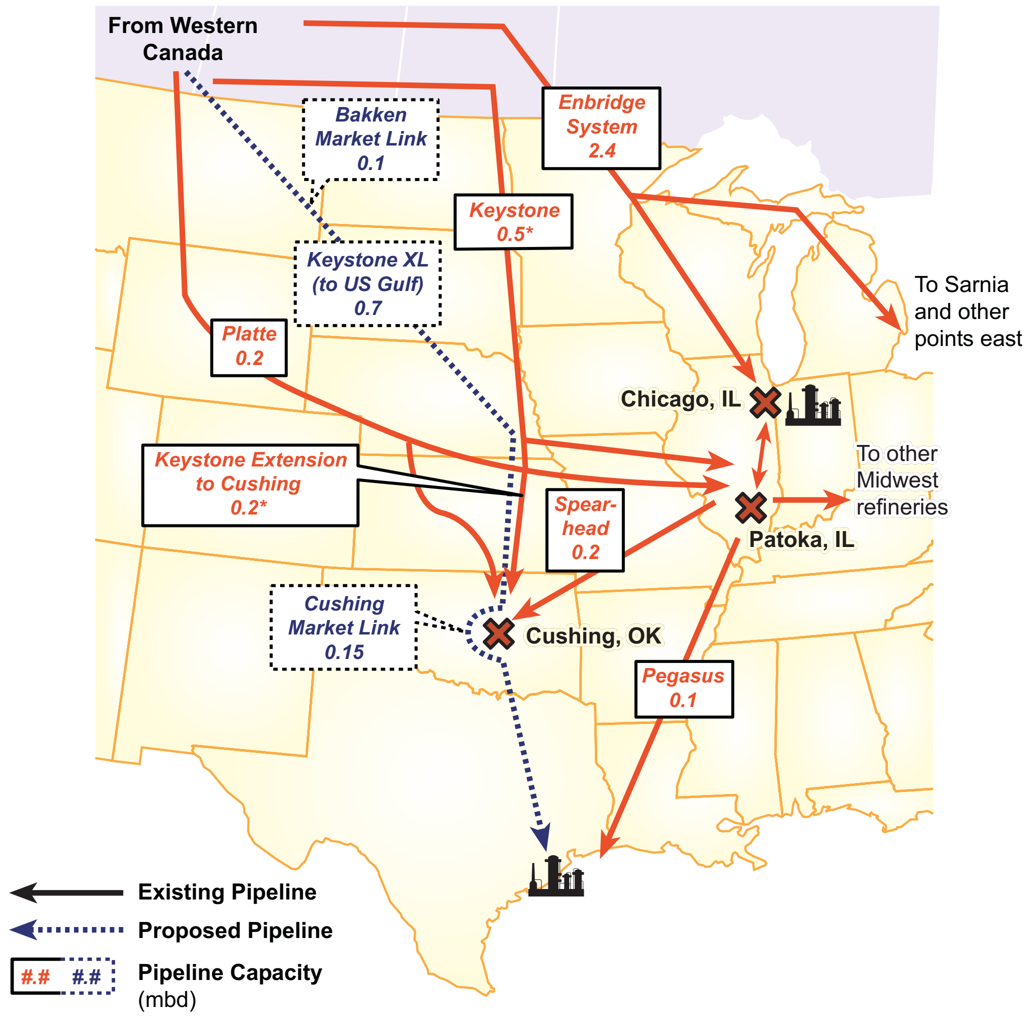
### Crude Oil Supply in the US Midwest: Nearing Saturation

IHS CERA projects that the bulk of oil sands export growth to the US Midwest will be a product called dilbit, a heavy crude oil (see the box "Oil Sands and Conventional Crude Oil Definitions"). To prepare for increasing heavy crude supplies, a number of Midwest refiners are adding sophisticated upgrading units, called cokers, to their refineries, enabling them to accept growing dilbit volumes.[2] The combination of new pipeline capacity and additional refining capacity geared to accept dilbit means that in the near term the Midwest market

1. In 2010 only 2 percent of Canadian crude oil exports were to other countries (source: Canada NEB).
2. Four refiners (Conoco Phillips/Cenovus Wood River, Holly Tulsa, BP Whiting, and Marathon Detroit) have recently expanded or are planning to expand their capacities to accept heavy crude. In total they are adding about 170,000 bd of new coker upgrading units.

**Figure 1**

**Current and Proposed Crude Flow from Western Canada to US Midwest and Gulf Coast**




Source: IHS CERA, company information.
Note: Distances not drawn to scale. Pipeline capacities are rounded.
*Keystone Cushing extension will be taken over by the Keystone XL when XL is operational.
The Keystone pipeline will run at 0.3 mbd (down from the current 0.5 mbd) when this occurs.
10410-3

can absorb additional oil sands production. However, considering the potential for oil sands production to double in the next decade, by 2015 oil sands dilbit exports will likely exceed the Midwest refiners' ability to process the heavy crude. It's possible that some Midwest refiners could further upgrade their refineries, increasing the market for dilbit. But growing Canadian supplies to the US Midwest have coincided with a renaissance in light crude oil production in the region, led by the Bakken tight oil play, mainly in North Dakota but also extending into Montana. Total production from the formation has grown from less than 10,000 bd in 2003 to an estimated 400,000 bd in 2011, making North Dakota the fourth-

**Oil Sands and Conventional Crude Oil Definitions**

**Conventional oil products.** The terms light, medium, and heavy are often used to describe the density of crude oil. Typically, light crude oil has a density greater than 32 degrees API, and naturally yields greater volumes of valuable transportation products (such as gasoline and diesel). Heavy crudes have a density typically defined as 22 degrees API or lower. Heavy crudes naturally yield higher volumes of heavy products (such as road asphalt). To use these heavy products for transportation fuels, they must be converted or upgraded into more valuable light components. Refineries with sophisticated upgrading units, called cokers, are required to convert these heavy products into gasoline and diesel. Crudes in between light and heavy are termed medium. The United States produces heavy oil in California and imports heavy oil from a number of countries, including Canada, Mexico, and Venezuela.

**Canadian oil sands products.** Raw bitumen is denser than heavy oil; it's solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with light oil liquid or converted into a synthetic light crude oil. The two most common products derived from oil sands are

- **Upgraded bitumen or synthetic crude oil (SCO).** This is produced from bitumen in refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions. SCO is typically a light sweet crude oil with no heavy fractions and an API gravity typically greater than 33 degrees.
- **Dilbit (bitumen blend, or diluted bitumen).** This is bitumen mixed with a diluent, typically a natural gas liquid such as condensate, to make the viscosity low enough for the dilbit to be shipped in a pipeline. Once mixed, dilbit is a heterogeneous crude oil mixture of about 22 degrees API, similar to the density and properties of other heavy crude supplies from California, Mexico, and Venezuela.

largest oil-producing state in the United States. IHS CERA estimates that production from the play could reach at least 800,000 bd by 2016–18. Production elsewhere in the Midwest is also rising: output in Oklahoma and Kansas has increased by about 10 percent since 2007. Consequently, with ample and growing light domestic crude supplies in the region, it is unclear whether refiners would make costly upgrades to process more heavy crude supply from Canada.

A sign of the need to expand pipeline capacity out of the Midwest, and of the oversupply of light crude in the region, is a lower price for West Texas Intermediate (WTI) crude oil relative to other major crude oils, including those traded on the US Gulf Coast and elsewhere in the world. WTI, priced at Cushing, Oklahoma, is the oil price that appears in the daily news. Historically WTI has been priced at a premium to other crude oils. The US Midwest was short of crude oil, and a higher price was needed to attract supply to refineries in the region and to reflect the high quality of WTI. Consequently, pipeline infrastructure was built to transport oil *to* the Midwest, but not *from* the Midwest. Cushing pipeline connections do not flow south to the US Gulf.

In a break from historical trends, there were times from 2006 to 2010 when WTI was priced several dollars below Light Louisiana Sweet (a crude oil produced in the US Gulf Coast) and Brent crude oil (a global price benchmark produced in the United Kingdom sector of the North Sea). But in recent months the WTI discount has ballooned to as much $18 per barrel as landlocked supply growth overwhelmed the Midwest crude oil market. WTI will remain vulnerable to significant discounts to other crude oils until more export capacity is developed to transport crude out of the Midwest to the US Gulf Coast.

The Keystone XL project could provide some relief for the oversupply of light crudes in the US Midwest. First, some Canadian light Synthetic Crude Oil (SCO) could bypass oversupplied light crude markets in the Midwest and go directly to the US Gulf Coast. Second, the project could transport some US domestic production from both Cushing and the Bakken to the US Gulf Coast.

What if increased oil sands access to the US market is derailed? Apart from the loss to consumers of a more dynamic pipeline network, Canadian oil sands producers would likely turn to Asia as a new export market, and US Gulf Coast refiners would continue to draw on current suppliers. However, some current suppliers such as Mexico and Venezuela are struggling to maintain production, and other suppliers are needed.

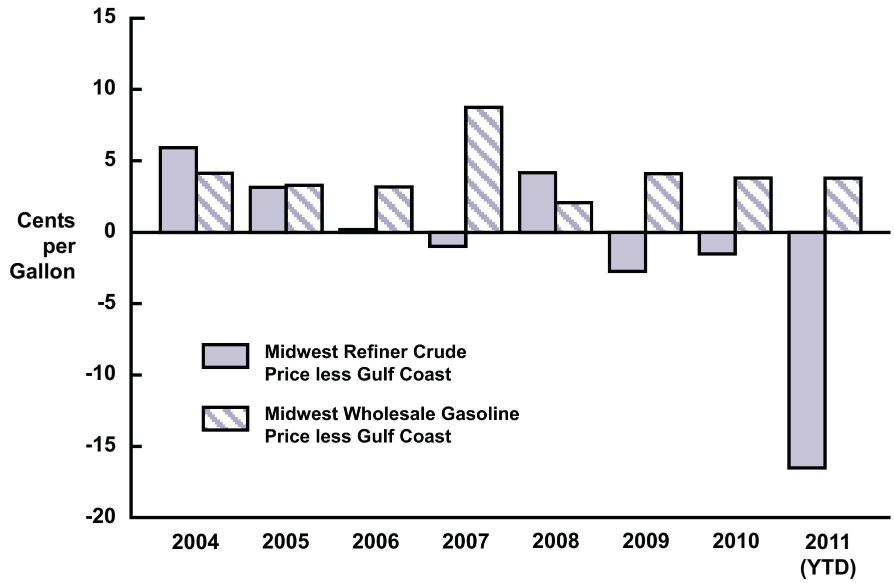
### Does a Lower WTI Price Relative to Other Crude Prices Result in Lower Gasoline Prices for Consumers in the Midwest?

The answer is no. The price a consumer pays for a gallon of gasoline in the Midwest is comparable to the US average. There is no WTI discount for gasoline. Indeed, the first quarter average wholesale price for gasoline in the Midwest was $2.52 per gallon, about $0.04 above the US Gulf Coast average. Midwest prices are slightly higher because the Midwest must import gasoline from outside the region. In 2010 the net volume of Midwest gasoline imports from elsewhere in the United States amounted to about 500,000 bd. To attract this supply, Midwest buyers must buy gasoline at global market prices; otherwise, sellers would supply other markets. The Midwest gasoline market is and will remain dependent on supplies from outside the region to meet demand, which means that Midwest gasoline prices will continue to be shaped by global forces.

For gasoline sold in the US Midwest, the global market is the price of gasoline in the US Gulf Coast, which is one of three global refining centers that shape the global market price for gasoline (Rotterdam in the Netherlands and Singapore are the other two major "benchmark" markets for refined products). The single most important influence of the global market price of gasoline—which determines the price of gasoline the US Midwest—is the global market price of crude oil. For many years the price of WTI was a good indicator of the level of global crude and Midwest gasoline prices. But the disconnection of WTI from the global crude oil market—which has intensified in 2011—means that WTI does not reflect price levels for either the global crude oil or gasoline markets. Figure 2 compares Midwest crude and gasoline prices with the Gulf Coast. In 2004, 2005, and 2008 Midwest refiners paid a premium for crude oil (compared with Gulf Coast prices), yet the relative gasoline price between the two regions was not affected. In 2011 Midwest refiners have obtained crude at price levels well below the Gulf Coast, but relative gasoline prices—which are set by global forces—have not been affected.

**Figure 2**

**Midwest Crude and Gasoline Prices Compared with the US Gulf Coast**




Source: IHS CERA.
10410-5

## Economic Logic: More Supply Lowers Price

Economic logic dictates that more supply lowers price at a given level of demand. The Keystone XL pipeline would increase oil supply available to the global oil market—and specifically to the US refining industry. It would not result in higher gasoline prices in the US Midwest.

The global market price for crude oil is the most important factor shaping the global market price for gasoline. Keystone XL would enable more supply to reach the global crude oil market—in this case, the US Gulf Coast. All else being equal, more supply of crude oil at a given level of demand would lower the global market price of gasoline—and thus lower the price of gasoline in the US Midwest. To be sure, many variables influence the price of oil: world oil demand growth, the pace of economic growth, the level of stability in major exporters, and the value of the dollar, to name just a few. But economic logic still holds: more supply lowers price at a given level of demand.

## QUESTION TWO: WHAT ARE THE LIKELY SUBSTITUTES FOR OIL SANDS CRUDES IF KEYSTONE XL IS NOT APPROVED?

Keystone XL would deliver Canadian crude oil to the US Gulf Coast. The US Gulf Coast refining region consumes large volumes of heavy crude oils—crudes that are similar in quality to much of the future oil sands supply, namely dilbit. The volume of heavy crude imports to the region has been growing steadily from 1.3 mbd in 2000 to 1.9 mbd in 2010 (see Table 1).

Gulf Coast refineries are well suited to turn heavy crude oil into valuable transportation fuels. The Gulf Coast is already home to 30 percent of the world's coking capacity, and that number is still growing. This is a good indication that heavy oil imports will continue to increase (see Figure 3 and the box "Problems a Complex Refinery Faces When Processing Lighter Crudes").

Although total heavy oil imports have been growing, imports to US Gulf Coast refiners from Mexico declined from 1.1 mbd to 0.8 mbd between 2005 and 2010. The decline was offset by growing imports, mainly from Brazil, Colombia, Canada, and Venezuela. (Even though Gulf Coast Venezuelan heavy oil imports have risen, overall crude oil imports are down 30 percent over the same period.) Without new oil sands crude supply, the Gulf Coast refiners will continue to process heavy crude oils, given their large investments in coking capacity. For example, a new medium-size coking unit—a piece of equipment geared to process heavy crude oil—can cost $2 billion. Processing lighter crudes would idle large, expensive equipment. Therefore, when considering the incremental emissions resulting from substituting Canadian oil sands supply for other crudes, heavy crude oils should be assumed to be the primary substitute.

To be sure, not all oil supply transported by Keystone XL is expected to be heavy, because some of the growing supplies of lighter Bakken and SCO could also be shipped on the pipeline. Currently about 37 percent of US Gulf Coast imports are light crudes, and SCO and Bakken could be an alternative for some of this supply. However, considering the relatively low growth outlook for oil sands SCO supplies and limited capacity for on-ramping Bakken oil, these volumes are expected to be about 20 percent of the products shipped in the pipeline.

The IHS CERA conclusion differs from that of the SDEIS, which assumes that, in the absence of oilsands, the supply would be replaced with lighter Middle Eastern crude supplies. Considering the economic incentives for US Gulf Coast refiners to process higher-profit heavy crude supplies, combined with a longer-term outlook for growing heavy crude supplies, this assumption seems unlikely. In the absence of oil sands, Gulf Coast refiners are expected to demand similar volumes of heavy crude oils.

**Table 1**

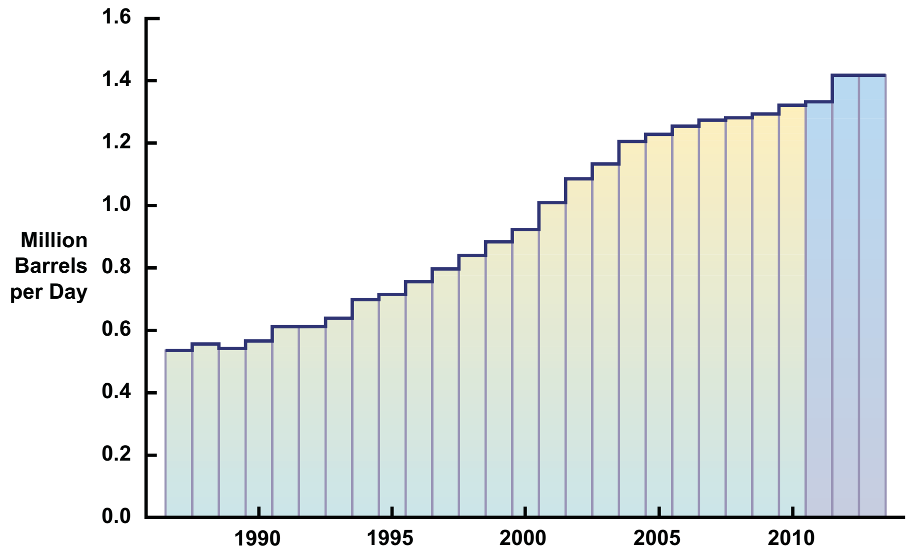
**Heavy Crude Oil Imports to US Gulf Coast Refining Region**

| | 2000 | 2005 | 2010 |
|---|---|---|---|
| Heavy oil imports (22 API heavier) (mbd) | 1.3 | 1.8 | 1.9 |
| Total oil imports (mbd) | 5.1 | 5.6 | 4.8 |
| Percent of imports from heavy oil | 25% | 32% | 39% |

Source: US EIA, IHS CERA.

**Figure 3**

**Current and Projected Total Coking Capacity in the US Gulf Coast**




Source: IHS CERA, EIA.
10410-4

**Problems a Complex Refinery Faces When Processing Lighter Crudes**

A coking refinery configured for heavy crudes faces two problems when processing lighter crudes:

- Light crudes yield more light products, which overfill the units that upgrade transportation fuel quality (motor octane, sulfur removal, etc.).
- Light crudes yield less heavy products, so the refinery reactors used for upgrading are underused.

The result is a reduction in the volumes of gasoline and diesel produced. If a refiner configured to process heavy crude is forced to process 100 percent lighter crudes, the volume of gasoline and diesel produced can decrease by 15–20 percent, with a corresponding decrease in profits. This gives the refiner an incentive to purchase heavy crude oils.

## QUESTION THREE: WHAT ARE THE INCREMENTAL GHG EMISSIONS ASSOCIATED WITH CONSUMING OIL SANDS?

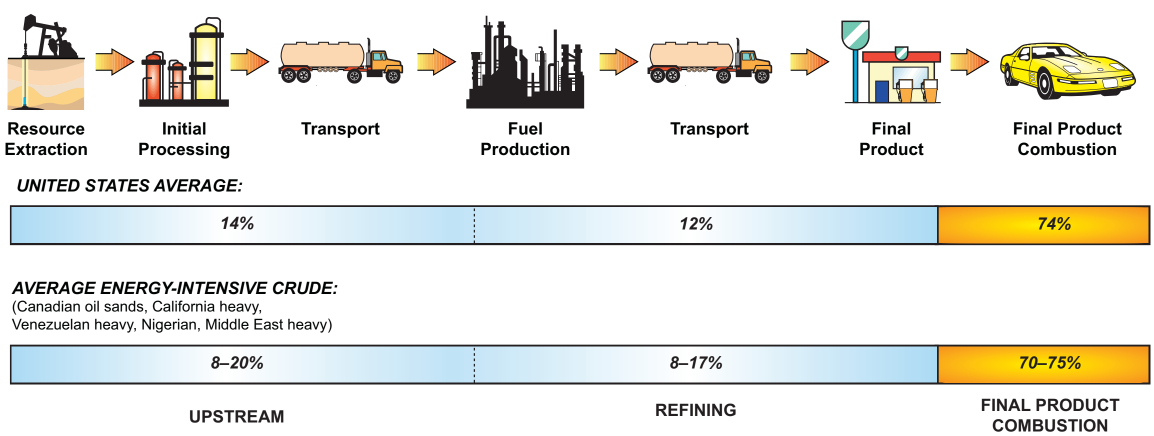
### Comparing Oil Sands Emissions to Other Crude Oils

The life-cycle (also known as "well-to-wheels") emissions for a petroleum fuel cover all GHG emissions—from the production, processing, and transportation through to the final consumption of the fuel (see Figure 4).

In a previous report, IHS CERA found that oil sands (and the SCO derived from oil sands) are 5 to 15 percent more carbon intensive than the average crude oil consumed in the United States, other carbon-intensive crude oils (some domestic production from California and some imports from the Middle East, Nigeria, and Venezuela) are also produced, imported, or refined in the United States.[1] Moreover, the average life-cycle GHG emissions for the average Canadian oil sands product *actually imported into the United States* is about 6 percent higher than those of the average crude oil consumed in the United States. This 6 percent figure is based on the actual composition of oil sands exports to the United States instead of an overall range for oil sands produced in Canada.[2] There are two reasons for the 6 percent figure. First, much of the SCO imported is from mining operations, which tend to have GHG life-cycle emissions at the low end of the 5 to 15 percent range. Second,

**Figure 4**

**Life-cycle GHG Emissions for Petroleum Fuels**




Source: IHS CERA.
Note: Blue = well-to-retail tank. US average based on 2005 (US DOE NETL).
10207-2_2305

1. See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right;* visit http://www.ihs.com/products/cera/multi-client-studies/oil-sands-dialogue.aspx to download.
2. In 2009 oil sands products processed in the United States were 45 percent SCO and 55 percent bitumen blends. The majority of SCO imports come from mining operations with life-cycle GHG emissions that are 6 percent higher than those of the average crude consumed in the United States. The most common bitumen blend is dilbit. Dilbit has lower life-cycle emissions than bitumen because only 70 percent of the dilbit barrel is derived from the oil sands (the remainder consisting of less carbon-intensive liquids such as natural gas condensates).

another large segment of US oil sands imports is dilbit, a blend of bitumen and condensates. About 30 percent of dilbit consists of condensates, which are light liquids and less carbon intensive to produce.

Looking forward, the GHG intensity of US oil sands imports is expected to stay relatively constant at around 6 percent higher than the average US crude consumed, with the potential to decline slightly.[1]

### Oil Sands GHG Intensity: Differences Between SDEIS and IHS CERA

The SDEIS, using data from a 2009 US Department of Energy National Energy Technology Laboratory (DOE NETL) study, reports that on a life-cycle basis gasoline consumed in the United States from oil sands results in 17 percent more GHG emissions than the average barrel consumed in the United States—higher than the IHS CERA value.[2]

There are two primary reasons for the difference. First and most important, DOE NETL assumes that the GHG intensity of oil sands extraction and upgrading is 1.5 times higher than IHS CERA's figure and outside the range of other studies. The NETL oil sands values do not represent the current GHG intensity of oil sands and therefore could be viewed as a mischaracterization. Also, the IHS CERA results (which compare oils sands to other crudes) are similar to the relative results of two other independent studies used within the SDEIS (Jacobs 2009 and TIAX 2009).[3] Second, the basis of comparison is different: IHS CERA considers the full barrel of products produced from each barrel of oil, whereas the DOE NETL study considers the emissions for only one product—gasoline. (See the appendix for a more detailed explanation of the differences between the IHS CERA results and other studies.)

The increase in GHG emissions from oil sands, and consequently from the proposed Keystone XL pipeline, is not as high as in the SDEIS or as perceived by some other observers. Indeed, life-cycle GHG emissions from the oil sands are comparable to those of many other crude oils consumed in the United States. The GHG intensity of likely crude oil substitutes is closer to that of oil sands than some believe.

1. The majority of oil sands growth is projected to be dilbit blend, whose emissions are on average about 6 percent higher than those of the average crude consumed in the United States on a life-cycle basis (the same as the current import average), and the majority of SCO will remain from mining operations whose emissions are also about 6 percent higher than average US crude on well-to-wheels basis. Going forward, ongoing improvements in energy efficiency combined with growing production of bitumen-only from mining operations will potentially lower industry-average emissions.
2. DOE NETL, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions,* March 27, 2009.
3. Jacobs and TIAX studies: *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy, July 2009; and *Comparison of North American and Imported Crude Oil Life-cycle GHG Emissions,* TIAX LCC, July 2009. See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right*. These studies were used as inputs to the IHS CERA meta-analysis of GHG emissions from oil sands and other crude oils.

## Drawing a Boundary Around the United States: Incremental GHG Emissions Associated with Consuming Oil Sands Crudes

If the Keystone XL pipeline were not constructed, heavy crude oils from other foreign producers would substitute for the majority of the lost Canadian oil sands supply. A smaller fraction of the oil sands supply, probably about 20 percent, is likely to be substituted by relatively lighter crude oils.

Assuming that 80 percent of the substitute crude is heavy, with a GHG intensity between Mexican Maya and Venezuelan heavy crudes, and 20 percent of the substitute crude oil is light, with a GHG intensity of a relatively lighter Middle East crude oil, IHS CERA estimates that on a life-cycle basis the construction of Keystone XL would result in between 7.5 and 11 million metric tons of carbon dioxide equivalent ($mtCO_2e$) per year more emissions associated with US oil supply than would be the case if no pipeline were constructed (see Table 2 and the appendix for more information on calculation).[1] Or put another way, the emissions are equivalent to between 1.5 and 2.1 million more vehicles on the road, or about 1.8 to 2.5 average-size coal-fired power plants.[2]

The IHS CERA result is well below the incremental GHG emissions assumed in the SDEIS base case, which ranged between 10 and 23 $mtCO_2e$ per year. There are two reasons for the discrepancy: first, SDEIS assumed that all oil sands supply is substituted for relatively light Middle East crude, which is unlikely. Second, the high side of the SDEIS GHG emissions range (23 $mtCO_2e$ per year) reflects the results of the DOE NETL study, which does not represent current operations and overestimates the GHG emissions for oil sands crudes.

## Does Drawing a Boundary Around the United States Make Sense?

If new market access for oil sands crudes does not materialize in the United States, economic forces would eventually drive oil sands supplies to new markets. From a global perspective, if oil sands production is not materially affected (and the oil is simply consumed in another

**Table 2**

**Life-cycle Incremental GHG Emissions of Displacing Keystone XL Oil Sands Crudes with Substitutes[1]**

($mtCO_2e$ per year)

| | 700,000 bd Pipeline | 830,000 bd Pipeline |
|---|---|---|
| Jacobs 2009 | (7.9) | (9.4) |
| TIAX 2009 | (9.4) | (11.1) |
| IHS CERA | (7.4) | (8.8) |

Source: IHS CERA.
1. Assumes that substitute crude is 80 percent heavy oil and 20 percent light oil.

1. Lighter Middle East crude oil is defined as 31 degrees API—just at the cutoff between light and medium crude oil.
2. GHG equivalencies based on EPA calculator—http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results.

country), then global GHG emissions are not affected. In fact, considering a scenario of oil sands crudes being transported to distant locations while other global crudes are transported from distant locations to the US Gulf Coast, it's likely that GHG emissions could be somewhat higher (because more energy would be consumed in transportation).

Even if the United States decides to restrict market access to oil sands crudes, it may not affect overall oil sands GHG emissions in the long term. But it would damage the US-Canada relationship and leave the United States more reliant on distant oil supplies.

## CONCLUSION

The oil sands provide an example of the need to find the right balance among economic, security, and environmental concerns. An informed dialogue will help both Canadians and Americans to reach a consensus that will enhance mutual prosperity and security. Key fundamental facts are

- The oil sands are a "mega" resource next door to the United States.
- Greater oil sands production has made Canada the number one supplier by far of foreign crude oil to the United States.
- Growth in oil sands production is reorienting imports and enhancing energy security through a land-based pipeline system with a neighboring country, not waterborne imports.
- Expanding pipeline capacity from Canada to the US Gulf Coast via the proposed Keystone XL project would provide more flexibility to the US supply system, allow infrastructure to begin to catch up with oil supply trends (namely the growing flow of Canadian oil), and enable increased US domestic production in the upper Midwest.
- A larger, more dynamic pipeline system benefits consumers, compared with a more constricted system that is less able to handle shifts in demand and supply.
- The Keystone XL project would increase oil supply available to the global market—and specifically to US Gulf Coast refineries. Economic logic dictates that more supply lowers prices for a given level of demand.
- The oil sands are part of a larger, dense network of trade and investment relations between the United States and Canada. Eight million American jobs depend on trade with Canada. Failure to enable oil sands to gain broader access to the US market could damage a bilateral relationship that has proved to be mutually beneficial for many years.
- Life-cycle GHG emissions of oil sands are 5 to 15 percent higher than those of the average crude oil consumed in the United States. The composition of oil sands products actually imported into the United States means that life-cycle GHG emissions of US oil sands imports are only 6 percent higher than for the average crude.

The United States and Canada have a deep and mutually beneficial relationship rooted in strong economic, political, and cultural connections. Energy, and oil in particular, is a key element of the overall relationship. Canada's oil sands have become an integral part of the fabric of US energy security—with the potential to play an increasingly important role for many years to come.

## APPENDIX

This appendix includes details on the methodology, calculations, and assumptions supporting our analysis in three parts:

- requirement for new pipeline capacity
- oil sands GHG intensity comparison with other studies
- calculating incremental GHG emissions from oil sands in Keystone XL compared with substitutes

## REQUIREMENT FOR NEW PIPELINE CAPACITY

As a result of the completion of two new pipelines that deliver Canadian oil to the US Midwest, Alberta Clipper and Keystone (totaling 1 mbd of pipeline capacity), we assume that growth in oil sands production over the next several years will flow to the Midwest. Using the Canadian Association of Petroleum Producers (CAPP) 2010 oil supply forecast from western Canada and assuming that Canadian demand for western Canadian crude supply remains flat, it would be between 2018 and 2020 before oil sands supply fills the existing surplus pipeline capacity (see Table A1).

However, pipeline capacity is not projected to be the bottleneck that curtails oil sands supply growth. Because of the increasing volumes of dilbit, which requires sophisticated refineries to upgrade the heavy crude, limited coking capacity will curtail growth first. Based on the current expansions (either under way or planned), we estimate that 600,000 to 750,000 bd of dilbit growth can be absorbed by the Midwest market, and this limit could be hit by 2015 (see Table A1). With ample light crude supply growth in the domestic market, Midwest refiners will have less incentive to spend billions of dollars in upgrades to take heavy crudes. The bottleneck will reduce the price of oil sands products and constrain growth. Also, oil demand in the US Midwest is generally flat to declining in the long term—as is overall US oil demand—so there is not likely to be a need for significant growth in refining capacity to serve the US Midwest market.

Another important consideration is that the Keystone XL project will redirect some of the existing Keystone pipeline capacity to the US Gulf Coast. This will reduce available pipeline capacity to the Midwest by about 200,000 bd. In this case, by 2015 excess capacity to the Midwest would be minimal. (Between the new Alberta Clipper and the Keystone pipelines to the Midwest, capacity would be reduced to about 840,000 bd, and this would be filled by 2016 with the current growth forecast; see Table A1).

## OIL SANDS GHG INTENSITY COMPARISON WITH OTHER STUDIES

### Differences in Oil Sands GHG Intensity: SDEIS and IHS CERA

The SDEIS (using data from the DOE NETL-2009) reports that on a life-cycle basis consumption of gasoline from oil sands results in 17 percent more GHG emissions than that from the average barrel of crude oil consumed in the United States. In our study, and

## Table A1

### Growth in Western Canadian Supply Compared with Pipeline Capacity

(thousands of barrels per day)

| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Western Canada supply growth (mbd) (source: CAPP 2010)** | | | | | | | | | | | |
| Oil sands: SCO | 745 | 836 | 883 | 882 | 878 | 896 | 900 | 947 | 994 | 996 | 1,014 |
| Oil sands: dibit | 986 | 1,118 | 1,251 | 1,444 | 1,564 | 1,669 | 1,820 | 1,848 | 1,941 | 2,112 | 2,202 |
| Conventional | 834 | 802 | 777 | 756 | 735 | 710 | 685 | 664 | 640 | 617 | 595 |
| Total western Canada supply | 2,565 | 2,755 | 2,911 | 3,082 | 3,177 | 3,275 | 3,405 | 3,459 | 3,575 | 3,725 | 3,811 |
| Less consumption in western Canada[1] | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 | 450 |
| Supply for pipelines leaving western Canada | 2,115 | 2,305 | 2,461 | 2,632 | 2,727 | 2,825 | 2,955 | 3,009 | 3,125 | 3,275 | 3,361 |
| Existing major pipelines leaving western Canada | | | | | | | | | | | |
| Export lines in operation prior to 2010[2] | 2,448 | 2,448 | 2,448 | 2,448 | 2,448 | 2,448 | 2,448 | 2,448 | 2,448 | 2,448 | 2,448 |
| New pipelines to US Midwest in 2010 (Alberta Clipper and Keystone) | 1,040 | 1,040 | 1,040 | 1,040 | 1,040 | 1,040 | 1,040 | 1,040 | 1,040 | 1,040 | 1,040 |
| Total pipeline capacity leaving western Canada | 3,488 | 3,488 | 3,488 | 3,488 | 3,488 | 3,488 | 3,488 | 3,488 | 3,488 | 3,488 | 3,488 |
| Implied spare capacity in pipelines leaving western Canada | 1,373 | 1,183 | 1,027 | 856 | 761 | 663 | 533 | 479 | 363 | 213 | **127**[3] |
| Potential new oil supply flowing on Alberta Clipper and Keystone (2010 baseline) | | 190 | 345 | 517 | 611 | 710 | **839**[4] | 894 | **1,009**[5] | 1,160 | 1,245 |
| Growth in dilbit to Midwest market (2010 baseline) | | 132 | 266 | 459 | 579 | **683**[6] | 835 | 863 | 956 | 1,127 | 1,216 |

Source: CAPP 2010, IHS CERA.

1. Assumes refineries run below total refining capacity and demand is static. In 2010 average crude runs for western Canada were 400,000 bpd (Source: NEB crude run reports).
2. Includes Enbridge System (1,868 mbd), Express (280 mbd), Trans Mountain (300 mbd).
3. If Keystone XL is not constructed; potential for all pipelines leaving western Canada to hit capacity.
4. If Keystone XL is constructed; potential for Alberta Clipper and Keystone lines to Midwest to hit capacity.
5. If Keystone XL is not constructed; potential for new Keystone and Alberta Clipper lines to hit capacity.
6. Potential for Midwest refiners to be oversupplied with dilbit.

comparing a more relevant full barrel of refined products, the average oil sands product exported to the United States results in life-cycle emissions that are 6 percent higher than for the average US barrel consumed.

There are two primary reasons for the difference. First and most important, DOE NETL assumes that the GHG intensity of oil sands extraction and upgrading are 1.5 times higher than IHS CERA and other study results. This is a mischaracterization of the GHG intensity of oil sands production. Second, the basis of comparison is different: IHS CERA considers the full barrel of products produced from each barrel of oil, whereas the DOE NETL study considers the emissions for only one product—gasoline.

**First, DOE NETL GHG emissions are about 1.5 times higher than the IHS CERA and others results.**

- **Oil sands mining and upgrading emissions.** Slightly more than half of today's oil sands production is from mining and upgrading. DOE NETL 2009 assumes a 2005 mining and upgrading emission value of 134 kilograms of $CO_2$ ($kgCO_2$) per barrel of SCO. The source for this value is not clear. The DOE NETL values are higher than those of any studies used in the IHS CERA analysis (which looked at the range of results across ten studies for mining and upgrading) as well as other operator reports (see Table A2). Using a 2005 GHG emissions value can result in mischaracterization of current operations; emissions in oil sands are not static, and on average the oil sands industry continues to improve its overall efficiency. For instance in 2005 the Syncrude project had emissions of 100 $kgCO_2$ per barrel. In 2009 emissions were reduced to 95 $kgCO_2$ per barrel of SCO.

- **Thermal extraction emissions.** Thermal methods inject steam into the wellbore to heat up the bitumen and allow it to flow to the surface. Two thermal processes are in wide use in the oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). On average SAGD has lower GHG emissions per barrel produced

**Table A2**

**Comparing Estimates for GHG Emissions for Mining and Upgrading SCO**

($kgCO_2e$ per barrel SCO)

| | DOE NETL 2009 | IHS CERA (average value)[1] | Syncrude (2009 Sustainability report)[2] | Suncor (2009, company data)[2] | Athabasca Oil Sands Project (Shell 2009 Oil Sands Report)[2] |
|---|---|---|---|---|---|
| Oil sands: mining and upgrading SCO | 134 | 80 (results range from 34 to 122) | 95 | 89 | 76 |

Source: DOE NETL 2009, IHS CERA.

1. Average value across 10 studies for SCO from mining, TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008,Jacobs-AERI 2009, Syncrude 2009/10, Shell 2006, NEB (2008), CAPP 2008.

2. Sources, Syncrude Sustainability reports, Suncor Energy Sustainability reports + company information, Shell Oil Sands Performance report, Muskeg River Mine and Scotford upgrader Sustainability report 2009.

than CSS. In 2009 over half of oil sands production was from the SAGD method, and SAGD volumes are growing.

For producing dilbit with thermal extraction, the DOE NETL study assumes that emissions are 1.5 times higher than the IHS CERA results (see Table A3). The DOE NETL study draws on a 2005 value for producing bitumen using the relatively high-emission CSS method (a process that represents less than half of current production). In the case of thermal production, there is no source for the estimate used in the DOE NETL 2009 paper; however, in a previous paper published in 2008 DOE NETL does provide a source for this value.[1] In addition, the estimate assumes the production of a barrel of bitumen-only, a product that cannot be transported via pipeline. IHS CERA assumes that dilbit, not bitumen, will be shipped down the pipeline and ultimately converted into refined products on the US Gulf Coast.

**Second, the basis of comparison is different.**

- **Gasoline basis compared with barrel of refined products.** Why did IHS CERA report the emissions per barrel of refined products rather than emissions per barrel of a specific product? In short, because each barrel of crude oil is converted into many products. When comparing the GHG emissions from different sources of crude, it is relevant to analyze the emissions resulting from all of the products produced, not just one. Additionally, allocating emissions across various refined products is a key challenge in life-cycle analysis. Including emissions from all products removes this potential source of error and confusion.

**Table A3**

**Comparing Estimates for Producing Dilbit and Bitumen-only**

(kg$CO_2$e per barrel)

| | DOE NETL 2009 | IHS CERA (average value) CSS[1] | IHS CERA (average value) SAGD[2] | IHS CERA Dilbit Average (50 percent SAGD, 50 percent CSS) |
|---|---|---|---|---|
| Oil sands: bitumen-only | 81 | 83 | 69 (results range from 56 to 80) | — |
| Oil sands: dilbit[3] | — | 60 | 50 | 55 |

Source: DOE NETL 2009, IHS CERA.
1. From TIAX-AERI (July 2009) (assumes SOR of 3.35).
2. Average value from six studies, equivalent to a SOR of 3.0. TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008,Jacobs-AERI 2009 (equivalent to SOR of 3).
3. Assumes that 70 percent of the barrel is from bitumen and 30 percent is natural gas condensate that emits 8 kg$CO_2$e per barrel produced.

1. DOE NETL "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008. For bitumen production, a 2006 estimate for CCS Imperial was used.

## CALCULATING INCREMENTAL GHG EMISSIONS FROM OIL SANDS IN KEYSTONE XL COMPARED WITH SUBSTITUTES

### Comparing Keystone XL IHS CERA Results with Two Other Studies: Jacobs 2009 and TIAX 2009

For the IHS CERA calculation of the average GHG emissions associated with the Keystone XL pipeline presented in this report, we did not include the results of the DOE NETL study, as it overestimates oil sands emissions. We included the results of Jacobs 2009 and TIAX 2009, as well as the results of our own meta-analysis, which compares the GHG emissions of oil sands to those of other crude oils.

Because all three studies use different assumptions in modeling GHG emissions (for instance, different system boundaries, refinery complexity assumptions, and allocation of emissions among refinery coproducts), it is not valid to compare the absolute GHG emission estimates across the studies—it is like "comparing apples to oranges." The IHS CERA meta-analysis overcame this limitation by creating a common framework to compare the life-cycle emissions of oil sands across 12 studies.[1] The results of each study were converted into common units and common system boundaries. The assumptions across studies were made consistent to create a uniform set of assumptions for crude transport, refining, and distribution. Using this methodology, crudes from multiple studies can be compared on an "apples to apples" basis. To download full meta-analysis, including the GHG emission of full suite of crudes, the US average baseline, and oil sands crudes, please visit www2.cera.com\oilsandsdialogue.

Since the methodologies of the three studies (IHS CERA, Jacobs, TIAX) are inconsistent, the only way to compare the results as presented in the original studies is to consider the relative results between the same crude oils within each study. Table A4 presents the incremental emissions between lighter Middle East Crude East (Saudi Medium), Mexican Maya, and Venezuelan crudes and the average oil sands crude. When compared on a relative basis, the results of IHS CERA are within the range of the other studies of the relative GHG emissions of oil sands compared with the other crudes. In all cases, the studies had other crudes modeled; however, for the purpose of this calculation of incremental emissions, these three potential substitute crudes were considered.

### Calculating Incremental GHG Emissions for Keystone XL

The difference between the average GHG emissions of oil sands crude and of the other three crudes on a per-barrel basis (last column of Table A4) was an input to the calculation of total GHG emissions from the Keystone XL pipeline. We assumed that 80 percent of the barrel is heavy crude (midway GHG emissions between Venezuelan crude and Mexican Maya) and the remaining 20 percent is lighter Saudi Medium crude. Taking the average incremental emissions on a per-barrel basis (between oil sands and this blend of crudes), we calculated the annual emissions for shipping 700,000 and 830,000 bd of oil sands in the Keystone XL pipeline for 365 days a year. The results of this calculation are the annual emission estimates for the Keystone XL, as shown in Table 2 of the main report.

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

## Table A4

### Comparison of Life-cycle Incremental GHG Emissions Between "Average Canadian Oil Sands" and Other Crudes

| | Original Study Data: Gasoline ($gCO_2e$ per MJ [LHV])[1] | Original Study Data: Diesel ($gCO_2e$ per MJ [LHV]) | IHS CERA Calculated[2] | Percent difference from "Average Canadian Oil Sands" (percent) | Incremental Emissions from "Average Canadian Oil Sands" ($kgCO_2e$ per barrel) |
|---|---|---|---|---|---|
| **Jacobs 2009** | | | | | |
| Average oil sands (SDEIS-ICF)[3] | 108 | 105 | 600 | | |
| Saudi Medium | 98.5 | 98 | 553 | (8) | (47) |
| Mexico Maya | 102 | 103 | 576 | (4) | (24) |
| Venezuela Bachaquero | 102 | 100 | 569 | (5) | (30) |
| **TIAX 2009** | | | | | |
| Average oil sands (SDEIS-ICF)[3] | 104 | 95 | 548 | | |
| Saudi Medium | 91 | 83 | 473 | (14) | (75) |
| Mexico Maya | 93 | 86 | 487 | (11) | (61) |
| Venezuela Bachaquero | 102 | 91 | 532 | (3) | (16) |
| **IHS CERA 2009** | | | | | |
| Average oil sands imported to United States (2006)[3] | | | 518 | | |
| Saudi Medium | | | 464 | (10) | (53) |
| Mexico Maya | | | 484 | (7) | (34) |
| Venezuela Bachaquero | | | 506 | (2) | (12) |

Source: IHS CERA, Jacobs 2009, TIAX 2009.
1. $gCO_2$ = grams of carbon dioxide.
2. To calculate the GHG emissions per barrel of crude for TIAX and Jacobs (which were originally on a product basis, such as gasoline and diesel), the average emissions were calculated assuming the following yields: Jacobs (59 percent gasoline, 35 percent diesel, and 6 percent others), TIAX (52 percent gasoline, 30 percent diesel, and 18 percent others). The emissions for a full barrel of crude oil were used when converted to full barrel of crude basis assuming 5.8 MMBtu per barrel of crude; this factor includes emissions from the full barrel including heavy products such as coke or asphalt, therefore 58 $kgCO_2e$ per barrel of crude was subtracted to estimate a per barrel of refined product basis. The IHS CERA results were already on a refined product barrel basis.
3. Jacobs 2009, TIAX 2009 the average Canadian oil sands export was assumed to be 50 percent dilbit, 44 percent SCO from mining, and 6 percent SCO from SAGD production using the same assumptions as the SDEIS-ICF study. For IHS CERA it was assumed to be 55 percent dilbit and 45 percent SCO from mining.

# Scenarios of Future Growth

January 2018

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Canadian Oil Sands Dialogue | **Strategic Report**

# Contents

# Scenarios of Future Growth

## About this report

**Purpose.** Since 2009, IHS Markit has made public research on issues surrounding the development of the Canadian oil sands. Since the turn of the last century, the oil sands have been a pillar of global oil supply growth. Yet, since 2014 a lower oil price has reduced investment and expectations of future growth. The ultimate arbiter of the oil sands' role in future supply is the long-term trajectory of the price of oil, which has also come into question. This report explores the outlook for oil sands growth under three IHS Markit energy scenarios.

**Context.** This report is part of a series from the IHS Markit Canadian Oil Sands 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.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted our own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by multistakeholder input from a focus group meeting held in Ottawa, Ontario, on 7 June 2016, as well as participant feedback on a draft version of the report. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for a list of participants and the IHS Markit team).

**Structure.** This report has five parts.

- Part 1: Introduction—An uncertain future for the oil sands
- Part 2: Lower prices have reduced investment in the oil sands
- Part 3: Oil prices, costs, and investor confidence
- Part 4: Price will conquer all—Scenarios of oil sands growth
- Part 5: Conclusion

Unless otherwise stated, values are in US dollars. All investment projections are normalized to 2016 constant/real dollars.

# Scenarios of Future Growth

### Key implications

Since the turn of the last century, the oil sands have been a pillar of global oil supply growth. Yet, since 2014 a lower oil price has reduced investment and expectations of future growth. The ultimate arbiter of the oil sands' role in future supply is the long-term trajectory of the price of oil, which has also come into question. This report explores the future of the Canadian oil sands under IHS Markit scenarios.

- **Lower prices have reduced investment in the oil sands.** Since the onset of the price collapse, upstream investment in new oil sands production capacity has fallen by two-thirds—from over $30 billion in 2014 to just over $10 billion estimated for 2017. Estimates for 2018 indicate that the level of investment may yet fall further.

- **Despite ongoing cost reductions, a number of uncertainties weigh on investments in new oil sands projects.** In 2017, the lowest-cost oil sands projects—cost to construct and bring online—require a WTI price under $50/bbl to break even. Yet, a constrained pipeline takeaway system, the prospect of increasingly stringent carbon policy, and shifting global marine fuel quality specifications—all of which have the potential to add cost or reduce the value of oil sands crude—complicate investment decisions in new oil sands projects.

- **The oil price holds more sway over the future of the Canadian oil sands than any other variable.** A notable and sustained improvement in the price of oil has the potential to offset uncertainties in the industry and lead to increased levels in investment. However, should prices linger in the mid-$50s/bbl WTI, the outlook for oil sands growth based on existing technology may remain more muted.

- **The long-flat production profile of oil sands assets makes a future without growth in the coming decade difficult to see—and a future with less output than today even more remote.** Oil sands facilities, once operational, are largely unresponsive to the oil price—with production neither ramping up nor ramping down materially. Oil sands production is more akin to base-load power generation, but for the oil market. Since the oil sands do not have to overcome production declines, growth can be more readily achieved.

- **The level and pace of future investment and growth is lower in all scenarios.** Regardless of the scenario, the rate of investment and growth in the oil sands will likely be lower and slower compared with the decade preceding the oil price collapse (the takeoff phase of Canadian oil sands development amid rising and historically high oil prices).

## Part 1: Introduction—An uncertain future for the oil sands

In 2014, upstream investment in new Canadian oil sands projects topped $30 billion. About 1 MMb/d of new production capacity was under construction.[1] Oil sands producers were focused on reining in capital cost inflation, which, if left unchecked, risked suffocating future growth.[2] However, in second half 2014, as US tight oil production continued to rise swiftly, a global supply glut began to emerge. By the end of the year, global oil benchmark prices had been halved from well over $100/bbl WTI to less than $50/bbl. The worst of it was in early 2016, when at times, WTI slipped below $30/bbl.

The impact of the 2014–15 price crash on cash flow from oil sands projects was immediate and dramatic. At the worst of it in early 2016, many operators found themselves producing at a loss. However, with few exceptions, oil sands projects continued to produce, and projects that were already under construction continued to completion. This ongoing activity served as a shock absorber for the Canadian economy and enabled Canada's oil industry to continue to grow production volumes.

1. Unless otherwise stated, all values are in 2016 US dollars. Source: Canadian Association of Petroleum Producers (CAPP), Statistical Handbook for Canada's Upstream Petroleum Industry, Oil Sands Expenditures, http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook, historical investment derived by Statistics Canada as provided to CAPP, retrieved 11 September 2017.

2. For more information on historical cost pressure in Canadian oil sands, see the IHS Markit Strategic Report *Oil Sands Cost and Competitiveness*.

Indeed, since the oil price collapse began, Canada's crude oil production has grown by almost 500,000 b/d, and it may rise by an additional 700,000 b/d by 2020.[3] Although most production growth has come from the completion of new oil sands projects sanctioned before mid-2014, production has also been buttressed by efficiency gains that have allowed more oil to come from existing facilities.

Despite the outlook for rising oil sands production through the end of this decade, the longer-term trajectory for the oil sands is arguably more uncertain than it has been in many years. Each year since 2014, investment and activity in the oil sands has declined. In 2017, investment in new and sustaining oil sands projects is estimated to be roughly one-third of 2014 levels—just over $10 billion in nearly 380,000 b/d of capacity under construction.

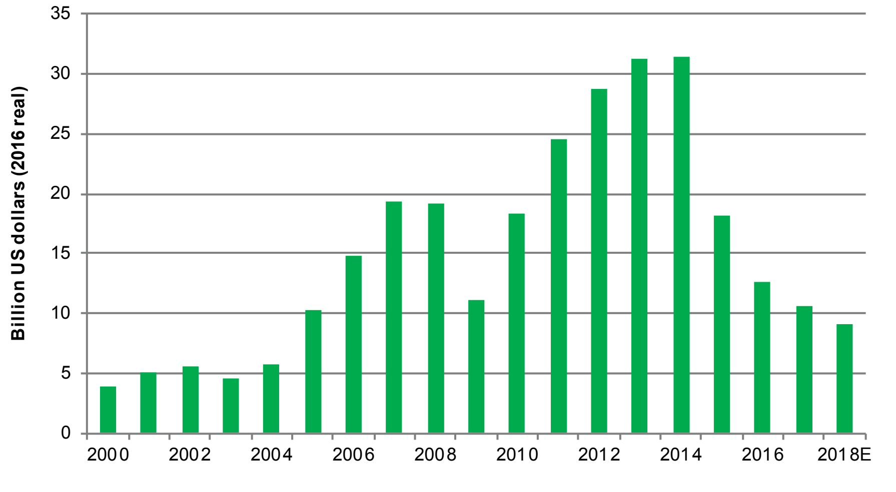
The long-term outlook for the oil sands depends in large part on the pace and scale of the oil price recovery. Compelling cases can be made for a world in which prices gradually recover in the coming years and remain modestly higher than in recent years; in which prices stay low for a protracted period; and in which prices are more volatile, reaching highs well above recent price levels and lows well below them as well. These cases are roughly the oil price trajectories of the three IHS Markit global energy scenarios: Rivalry (our base case), Autonomy, and Vertigo. Although IHS Markit scenarios cover the entire global energy landscape, this report explores the outlook for oil sands investment and production growth in each.

## Part 2: Lower prices have reduced investment in the oil sands

In 2014, the Canadian oil sands were firing on all cylinders—more than $30 billion was invested in the construction of over 1 MMb/d of production capacity. If operating costs and royalties are considered, the investment figure for 2014 nearly doubles, approaching $60 billion.[4] However, when the oil price began to collapse in second half 2014, the cash flow of the oil sands industry began to dry up, and during the price nadir in first quarter 2016 many operators produced oil at a loss. Yet, very few operations shuttered. Most facilities counterintuitively found ways to increase output to reduce per-unit production costs. Moreover, most new projects sanctioned before the price crash continued toward completion.

Figure 1

**Oil sands capital investment**




Note: E = estimated.
Source: CAPP, IHS Markit

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Each year since 2014, investment in the oil sands has fallen as projects have been completed and brought online and few new projects have been sanctioned (see Figure 1). Indeed, this is part of a trend that has led to a 45% reduction in spending on new oil projects globally from 2014 to 2017.[5] In the oil sands, the last of the projects sanctioned prior to the price collapse—two large mines—will be completed in 2017. Three in situ steam-assisted gravity drainage (SAGD) projects—ones that were sanctioned prior to the oil price collapse and delayed owing to it—moved back into construction in 2017. However, the scale of the projects wrapping up in 2017—with combined capacity of nearly 290,000 b/d—is greater than the scale of the projects expected in construction in 2018—110,000 b/d. This suggests that oil sands investment activity is set to fall further.

3. Based on annual averages of synthetic crude oil (SCO) and bitumen from 2014 to 2017 and 2017 to 2020, respectively.

4. CAPP, Statistical Handbook for Canada's Upstream Petroleum Industry, Oil Sands Expenditures, http://www.capp.ca/publications-and-statistics/statistics/statistical-handbook, historical investment derived by Statistics Canada as provided to CAPP, retrieved 11 September 2017.

5. IHS Markit Upstream Costs & Expenditures, https://www.ihs.com/products/upstream-costs-expenditures.html.

## Part 3: Oil prices, costs, and investor confidence

Despite the resilience shown by oil sands projects in operation or under construction, the outlook for future development activity and associated economic benefits remain a source of uncertainty for Canada.[6] With 165 billion bbl of established reserves, great potential remains in Canada's oil sands.[7]

The projected oil price and estimated cost of a project are the two most important variables a company weighs in deciding whether to invest in a new development. This section discusses the factors that will influence future oil sands project economics, and the next section explores different oil price futures and the possible implications for future oil sands investment and production.

### Oil sands costs have fallen—and may fall further

The cost to build and produce oil from an oil sands project can be a source of confusion. There are two distinct types of oil sands production—in situ and mining. Besides both producing oil from the oil sands, they otherwise have little in common. The difference in the cost to maintain production from existing facilities and the cost to construct a new project can be another source of confusion. These differences can result in very different cost estimates.

The cost to operate and sustain an existing oil sands facility is far less than the full-cycle cost or the cost to build, operate, and sustain a new one. This distinction is arguably more important for the oil sands than for many other sources of global supply. This is because, while production from most global oil projects will decline over time, output from an oil sands facility, if properly maintained, does not in the medium to long term. In 2017, IHS Markit estimates that most oil sands (both mining and in situ) operations required a WTI oil price of $30–40/bbl to cover the cost of operating and sustaining operations and marketing the bitumen produced.[8] Most operations in 2017 would have been on the lower end of this range.[9]

If the cost to build an oil sands facility is taken into account (and assuming a 10% return on capital), in addition to the operating, sustaining, and marketing costs, the full-cycle cost of a new project is higher. A new mining operation would be more expensive, requiring greater than $70/bbl in 2017 to break even. New in situ operations, specifically SAGD projects, require just over $50/bbl WTI. However, because existing in situ facilities can leverage established infrastructure, in situ expansions can have the lowest breakevens. IHS Markit estimates that in situ expansions, specifically of a SAGD operation, could break even around $48/bbl WTI in 2017.

As projects are redesigned, standardized, and descaled to be more efficient, reductions in labor, steel, and construction time could further reduce up-front capital outlay and/or increase productivity and accelerate payback—improving project economics. New technologies that displace steam used for in situ extraction with noncondensable gases and solvents are moving from pilot to deployment and could increase production from both existing and new operations alike, lowering capital intensity and improving project economics.

### Expectations—and confidence—are key to future investment decisions

Decisions to advance projects in the oil sands—and elsewhere—in theory are based on confidence that the oil price will be high enough over the life of the asset to generate a positive return for investors. For oil sands projects, the expectation of the future trajectory of oil prices two to three years in the future may be more relevant given the lead time to construct and bring online new production capacity. However, the reality is that the current oil market sentiment exercises much influence over expectations of future oil prices. Despite ongoing cost reductions, producers likely need a price and future price expectation well in excess of current breakevens. Should WTI linger in the mid-$50s or below, companies may still struggle to justify sanctioning a new oil sands project, based on existing

6. For more information on the historical scale of associated economic benefits, see the IHS Markit Strategic Report *Oil Sands Economic Benefits: Today and in the future*.

7. For more information, see Alberta Energy Regulator, ST98, Table 1: Resources, reserves, and production summary, 2016, http://aer.ca/data-and-publications/statistical-reports/executive-summary, retrieved 4 July 2017.

8. Marketing of bitumen requires either the purchase of diluents to dilute bitumen to meet pipeline specification or the upgrading of bitumen to lighter SCO. Both processes add cost. The resulting crude oil product in either scenario also then must be transported to market and adjusted for quality to obtain a WTI equivalent.

9. However, some operations do require higher prices, above $40/bbl WTI, but these are fewer in number and typically smaller in output.

technologies.[10] A brightening of the oil sands investment outlook will likely require further declines in project costs and greater confidence that oil prices will be higher, on average, in the future than they are today. Unfortunately, in addition to a volatile oil price, a number of other uncertainties—some transitory and some particular to western Canada—currently complicate the oil sands investment case.

## Uncertainties facing the oil sands

In addition to the oil price, the oil sands face several other challenges that create uncertainty for investors. A brief description of these challenges follows, but fundamentally they all have the potential to add cost to oil sands operations and/or reduce the price that producers obtain for their crude oil.

Some of the challenges are unique to the industry and are, in part, the result of poor public perception of the industry and an organized environmental opposition to further development; others are more global in nature and are not unique to the oil sands. Three key challenges are

- **A constrained pipeline takeaway system.** The timing of new pipeline capacity and corresponding impact on western Canadian heavy oil benchmarks add uncertainty to future returns for oil sands producers. As western Canadian heavy oil production has grown, the pipeline system has struggled to keep pace. Late in 2017, transportation bottlenecks reemerged, causing price discounts for western Canadian heavy oil, compared with what could be obtained had crude oil been able to clear the market more efficiently.[11]

  A number of pipelines have been proposed to resolve this situation and have been met with opposition. Opposition has contributed to delays in the construction and streaming of these pipelines—creating uncertainty for the future price of western Canadian heavy crude oil. With new western Canadian pipeline capacity unlikely to come online before late 2019 at the earliest, and heavy oil sands production set to rise further between now and then, more crude oil from the oil sands is expected to move by rail. The movement of crude by rail is anticipated to come at a greater cost, reducing the value of western Canadian heavy oil. The longer the pipeline system remains constrained, the greater the volume of oil that will move by rail—and the more it may cost to ship western Canadian crude oil to market as railroads seek to cover the incremental cost of building new rail capacity to support greater movements.[12]

- **Increasingly stringent carbon policies.** In recent years, governments in Canada have moved to increase both the coverage and stringency of greenhouse gas (GHG) reduction policies. Putting a price on carbon is not new to the oil sands industry. In 2007, Alberta became the first jurisdiction in North America to establish a carbon price. More recently, the province moved to strengthen its carbon pricing policy and placed an absolute cap on oil sands GHG emissions. At the federal level, a minimum national carbon price will ensure the price in Alberta will escalate from C$30 per metric ton to C$50 per metric ton by 2022. IHS Markit believes that carbon levies to 2022 have not materially altered the economics for most oil sands production.[13] However, current policies are designed so the cost of compliance increases for more carbon-intensive operations. The impact in a lower price scenario could be material if those facilities are unable to reduce emissions intensity. IHS Markit believes that current policies will encourage greater investment in GHG reduction measures while reducing the incentive to invest in more challenging reservoirs (which could result in more GHG-intensive production). At the same time, the oil sands are one of the few sources of global oil supply that currently face an increasing cost of carbon. For potential investors in the oil sands, this adds an additional layer of complexity and risk that is not yet present in most other oil-producing jurisdictions. (For more details of carbon policies relevant to the oil sands, please see the text box "Carbon policies and the Canadian oil sands.")

- **Shifting global marine fuel specifications.** In 2016, the International Maritime Organization (IMO) agreed to reduce sulfur dioxide ($SO_2$) emissions from the global shipping fleet starting in 2020.[14] If enforced, these rules could negatively

10. Oil sands operations typically receive a price below WTI subject to transportation and quality adjustments, which can change over time.

11. From January to December 2017, Western Canadian Select, a heavy crude oil price benchmark in Canada, averaged about $11/bbl beneath WTI, an inland US light, sweet crude oil benchmark. However, beginning in late November the difference in price began to grow, reaching as much as $26/bbl at times in December and averaging over $23/bbl that month.

12. For more information on western Canadian crude-by-rail dynamics, please see the IHS Markit Strategic Report *Pipelines, Prices, and Promises—The story of western Canadian market access*.

13. On 6 December 2017, Alberta finalized the rules for how carbon pricing will be levied on the oil sands. For more information, see "Carbon Competitiveness Incentives protect jobs," Alberta government, 6 December 2017, www.alberta.ca/release.cfm?xID=51121C0A77352-9809-750B-7CC8BD5ED81774AD, retrieved 6 December 2017.

14. For details of the IMO fuel specifications, see *Sulphur oxides ($SO_x$) and Particulate Matter (PM) – Regulation 14*, IMO, retrieved 27 November 2017.

## Carbon policies and the Canadian oil sands

Alberta and Canada have put a price on carbon for the oil sands. Alberta has had a price on carbon in place since 2007 for all large emitters. More recently, it has taken measures that would expand coverage to fossil fuel combustion and increase the carbon price to $30 per metric ton for large emitters and $30 per metric ton in 2018 for the rest of the economy.[1] The federal government is backstopping provincial measures with a national price, which will apply in regions that have not advanced their own equivalent policy and ensure that the price in Canadian regions will rise to $50 per metric ton by 2022.[2]

Oil sands production is considered an emission-intensive, trade-exposed sector. Emission intensive means that the level of emissions per unit of output is relatively high. Trade exposed means that the oil sands export most of their output, which competes with producers from around the world. For these industries, which are not limited to oil sands, carbon pricing can create a cost disadvantage that their global peers may not face. In this circumstance, firms that compete globally may physically relocate or lose out to their competitors. Along with this, the investment, employment, and emissions could end up being redistributed to jurisdictions with less stringent policies. If countermeasures are not taken, the local economy with more advanced climate policies may be negatively impacted with little impact on global GHG emissions.

To protect against this outcome, Alberta and Canada have opted to provide emission credits to these sectors. The value of the credits are set by the sector-level emission intensity benchmark (emissions per unit of output) and are allocated to facilities based on output. These are known as output-based allocations. The higher the production level, the more credits are allotted, but at a set emission intensity value. Under this credit system, higher emission-intensive facilities will have insufficient credits to cover their total emissions and will have to pay on the remainder, while more efficient operations may be able to bank or vend surplus credits. In this way, the price acts to encourage GHG reductions while minimizing the incremental cost that could result in a shift of investment, economic benefits, and emissions to other jurisdictions. For the oil sands, the credit value will be based on top the quartile of performers for each major oil sands segment, in situ extraction, mining extraction, and upgrading. Alberta has dubbed the policy the Carbon Competitiveness Incentives and will be phasing it in over 2018 and 2019. It will be coming into full force in 2020.[3]

Assuming compliance is met solely through payment of the carbon price, based on the performance of in situ operations (both SAGD and cyclic steam stimulation [CSS]) in 2017, the estimated average cost of compliance for in situ projects could remain below C$0.80/bbl in 2022 when the national price of carbon is expected to reach C$50 per metric ton.[4] However, more carbon-intensive operations will face a greater cost of compliance. If these facilities are unable to reduce their emissions intensity, they could face a potential cost of carbon between C$3 and C$4/bbl in 2022 (based on the upper range of in situ projects in 2017).[5]

The oil sands also face an absolute cap on emissions as part of provincial policies. In each of the three IHS Markit scenarios discussed later, the cap is not expected to restrict oil sands production to 2030. This being said, our assessment is sensitive to assumptions about the degree of future investment, and thus production, and future carbon intensity of extraction. To be sure, a number of details of the oil sands emission cap policy have yet to be finalized.

When investors are deciding today whether to invest in an oil sands project that may operate over 30 years, and the potential exists—however remote—that that operation could face restrictions at a later date that may affect its ability to produce, the investors will factor in at least some of that risk today. Although technology may exist to drive significant reductions, until it is commercially deployed on a large scale, investors may view oil sands GHG policy as an additional investment risk that other regions do not face.

1. For more information, see “Climate change,” Alberta government, https://www.alberta.ca/climate-change.aspx, retrieved 6 December 2017.

2. The Pan-Canadian Framework allows for quantity-based benchmarks for regions that adopt cap-and-trade systems, and, as a result, the price in these regions can vary from the national level.

3. For more information, see “Climate change,” Alberta government, https://www.alberta.ca/climate-change.aspx, retrieved 6 December 2017.

4. The IHS Markit estimate of the cost of compliance in 2022 is based on the weighted industry average emission intensity over the first nine months of 2017. The top quartile of in situ operations was used as the benchmark in 2022 as provided by established benchmarks in Schedule 2 of the Carbon Competitiveness Incentive Legislation. See http://www.qp.alberta.ca/1266.cfm?page=2017_255.cfm&leg_type=Regs&isbncln=9780779800193, retrieved 11 January 2018.

5. Based on the first nine months of data in 2017, the production weighted average efficiency of in situ operations (including SAGD and CSS) as measured by the steam-to-oil ratio (SOR) was 3.06. For this estimate, operations with SOR between 5 and 6 were used to represent more carbon-intensive operations. Based on the first nine months of operations in 2017, and after adjusting for facilities in ramp-up that had temporarily high SOR, there was one operation near 5 and three operations between 5 and 6. Historical in situ SOR data was derived from Alberta Energy Regulator, “Alberta In Situ Oil Sands Production Summary,” ST-53 https://www.aer.ca/data-and-publications/statistical-reports, retrieved December 2017. IHS Markit analysis is preliminary as some details on the application of Alberta’s new policy are still forthcoming.

impact the value of higher-sulfur crude oil, such as from the oil sands, for a period beginning in 2020. $SO_2$ emissions result from the combustion of high-sulfur fuels. Although multiple compliance options are available to shipowners, such as installation of shipboard scrubbers, which can remove $SO_2$ from the exhaust gases, the primary means of compliance in the immediate term will likely come from the consumption of lower-sulfur marine fuels. Heavier crude oils, including from the oil sands, typically contain higher levels of sulfur. Increased investment will be required to remove additional sulfur or address $SO_2$ emissions from exhaust gases. In either case, the value of high-sulfur crude oil would be expected to temporarily weaken relative to lower-sulfur crudes. This, in turn, creates incentives to invest in the infrastructure necessary to address sulfur content and allow the price to gradually recover. Key to the degree of the IMO impact on light-heavy differentials will be the level of compliance. Should compliance be gradual, the impact on heavy oil prices could be less pronounced. If compliance is strong at the onset, the price impact could be greater but would likely span a shorter period. Regardless, the pending IMO rule creates uncertainty about the future price of heavy, sour crude oil at the onset of the next decade.[15]

## Part 4: Price above all—Scenarios of oil sands growth

The oil sands are a business of big investments, long lead times, and enduring asset life. Depending on scale, oil sands projects can cost between $1 billion and well over $10 billion and require between two and five years to be brought online.[16] Expansions of existing thermal projects are at the lower end of both these ranges, and new mining operations are at the upper end. In short, oil sands investors need to wait at least a few years before their large capital outlays begin to generate returns. In return for a large up-front investment and lag in cash generation, investors get a very long life asset. If properly maintained, oil sands facilities can produce a relatively stable volume of oil for 30 years or more. This long production life is a unique aspect of oil sands operations, and it allows production growth to be more readily achieved than in most other global oil plays where output declines more rapidly.[17] Oil sands production is arguably similar to base-load power generation, but for the oil market. The absence of meaningful declines makes a future without oil sands growth difficult to see.

As a result of long project lead times, oil sands production growth to the close of this decade is essentially locked in with investment decisions having to have been made by now. Indeed, although investment decisions in the oil sands (and elsewhere) can have an almost immediate impact on jobs and the economy, the impact of such decisions on output is delayed—in the case of the oil sands by two years or more.[18]

The production profile in the coming decade (after 2020), by contrast, is much less clear. Currently, the investment case for the oil sands is challenged as outlined above. The prospect of further project cost reductions could provide a counterbalance but remains unproven.

Ultimately, though, the pace of oil sands investment and production growth depends more than anything else on oil prices. An increase in the price of oil will make oil sands investments unambiguously more attractive, all else being equal. To be sure, there is much nuance in projecting oil investment and production in different price environments. For example, a protracted period of lower prices may result in less investment but greater cost reductions and efficiency gains; and a period of rising prices may lead to more investment and production growth, but also more rapid cost inflation and fewer efficiency gains.

In our base case, IHS Markit believes that oil prices will gradually recover over the next several years and then stay at higher levels on average through 2030. However, credible cases exist that could lead oil prices to traverse very different paths, including those in the two alternative IHS Markit scenarios. Below, we outline the three IHS Markit energy scenarios as they pertain to oil and explain how oil sands investment and production fare in each.

15. For more information on IHS Markit views on the IMO impact, see the IHS Markit News Release *New Low-Sulfur Requirements for Marine Bunker Fuels Causing Scramble for Refiners and Shippers, IHS Markit Says,* retrieved 7 September 2017.

16. This estimate is based on a representative range of new or greenfield historical oil sands projects. Expansions of in situ facilities are typically lower cost, and smaller-scale projects do exist that would reduce capital cost. However, historically project scales have been larger, from 30,000 b/d for thermal in situ development to even greater for large mining operations. For more information on historical oil sands capital cost, see the IHS Markit Strategic Report *Oil Sands Costs and Competitiveness*.

17. With proper maintenance, central processing plants for mining and in situ operations access massive reservoirs sufficient to produce a steady volume of oil for decades.

18. Notably, because of the lag between the sanctioning of a project and first oil, oil sands production growth is a relatively poor indicator of health of the industry.

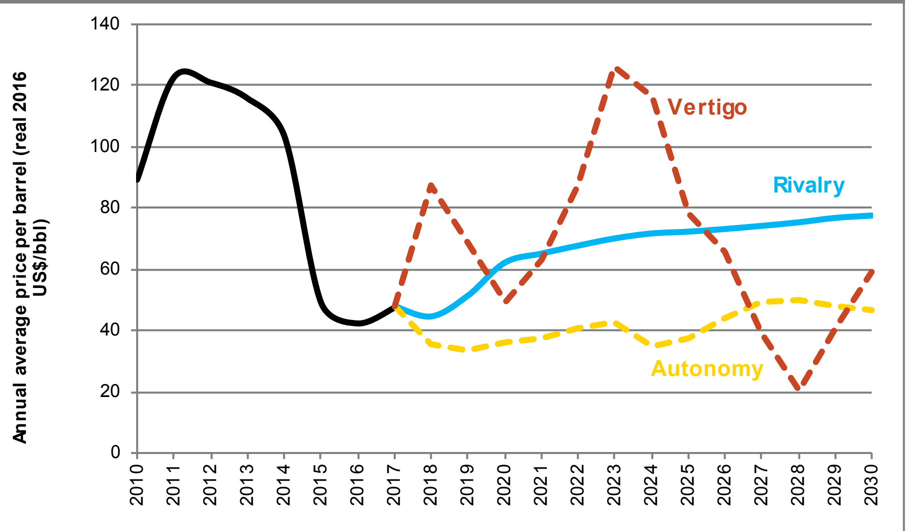
## Overview of the IHS Markit energy scenarios

IHS Markit uses scenarios to challenge conventional thinking in an uncertain world. To this end, we offer three views of the future of oil to 2030:

- **Rivalry (the IHS Markit base case).** Rivalry is a world where global oil demand rises gradually over the next decade, although greater interfuel rivalry, efficiency gains, and government policy decelerate the pace of growth. Meanwhile, price and cost continue to regulate world oil supply as OPEC has little success in managing output. Gulf-5 and North American tight oil are the two key sources of supply growth over the next decade.[19] But supply from these two areas is not enough to offset declines from producing fields and meet demand growth. Oil prices gradually rise in the coming years as world oil demand growth remains robust and the impact of lower upstream spending reduces supply growth. Higher prices are needed to incentivize investment in higher-cost projects that are necessary to satisfy demand. But the annual average prices do not return to anywhere near the $100 plus levels between 2011 and 2014. By 2030, the Dated Brent price approaches $80/bbl in real terms. Overall, Dated Brent averages about $68/bbl in 2017–30.
- **Autonomy.** Autonomy is a world where low upstream costs and the expansion of tight oil production outside of North America allow more oil to be produced at much lower prices than once thought possible. World oil demand peaks in the mid-2020s owing in large part to the combined impact of rising fuel economy standards, driverless technology, mobility service companies, and electric vehicles (which include pure battery electric vehicles and plug-in hybrid electric vehicles). Policy supports these disruptors of oil demand because they lower the cost of mobility via the car and are seen as addressing urban congestion and air pollution. Low upstream costs and weaker oil demand keep oil prices low through the next decade. Dated Brent averages about $42/bbl in real terms in 2017–30.

Figure 2

Crude oil price outlook to 2030 by scenario




Source: IHS Markit © 2018 IHS Markit

- **Vertigo.** Vertigo is a world where a volatile global economy leads to frequent mismatches between supply and demand. Global oil producers chronically misjudge demand cycles. This leads to extreme oil price swings. Rising prices lead to rising upstream costs, but costs do not fall as quickly as prices during downturns, straining producer profit margins. To 2030, in real terms, the annual average Dated Brent price rises to $90/bbl, falls to $50/bbl, rises to $130/bbl, and falls below $20/bbl, before recovering again. All in all, Dated Brent averages about $70/bbl in 2017–30.

See Figure 2 for the oil price tracks in the three scenarios and Figure 3 for an overview of the three scenarios.[20]

## Scenarios of oil sands growth

How do oil sands investment and production fare in these three scenarios?

In **Rivalry**, oil demand is robust enough to support a gradual recovery in oil prices. This incentivizes an increase in upstream production investment. Carried forward by projects sanctioned prior to the 2014–15 price crash, oil sands

19. The Gulf-5 is a group of low-cost producers in the Middle East comprising Saudi Arabia, Iran, Iraq, Kuwait, and the United Arab Emirates.

20. For more information on the IHS Markit energy scenarios, please see Long-Term Planning and Energy Scenarios, https://www.ihs.com/products/long-term-energy-planning-scenarios.html.

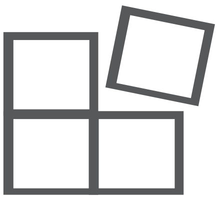
Figure 3

**IHS Markit scenarios**

**Rivalry**
IHS Markit planning scenario

**Most intense competition in history among energy sources for market share amid evolutionary social and technological change**

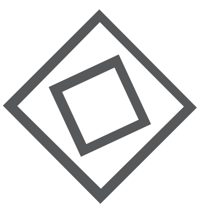
- The energy rivalry is driven by four factors: price differentials, environmental concerns, technology improvements, and energy security.
- Gas and electricity loosen oil's grip on transport demand; renewables become increasingly competitive with gas, coal, and nuclear in power generation.



**Autonomy**

**Transition of energy mix from fossil fuels at a much faster pace than expected**

- Market, technology, and social forces decentralize the global energy mix.
- A mobility revolution radically alters how cars are sold, used, and powered.
- Generational change and urbanization pressures alter energy demand dynamics—demand for coal and oil falls.
- Breakthrough occurs in electricity storage and solar photovoltaics.
- Development of unconventional oil and gas is more widespread than anticipated.



**Vertigo**

**World economy like weather on a mountaintop—sunny and pleasant one moment, then engulfed in fog and rocked by hurricane-force winds the next**

- Economic instability undermines confidence and exacerbates risk aversion.
- Volatile economic growth creates mismatches between demand and supply.
- Conservative capital investment spending slows the move to a less carbon-intensive economy.

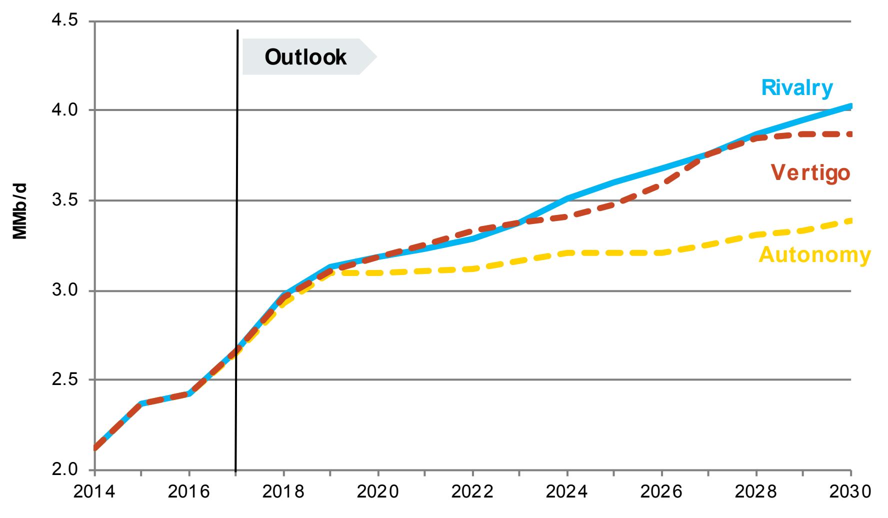
Source: IHS Markit



production maintains strong growth to 2019, as shown in Figure 4. Yet investment in the oil sands continues to decline, bottoming out in 2018 above $9 billion—less than one-third of the level in 2014 (see Figure 5). Investment gradually recovers but remains well below early 2010 levels. For the remainder of this decade (to 2020), investments are focused primarily on furthering efficiency gains at existing facilities, with only a handful of in situ expansions proceeding and no greenfield projects. In the early 2020s, oil prices continue to gradually recover and investors slowly become more comfortable as uncertainties facing the oil sands (including transportation constraints and the rising carbon price) are better understood. This leads to a gradual rise in investment as efforts to bring down project costs bear fruit and, together with a higher oil price, give companies confidence to commit more

Figure 4

**Oil sands production outlook (SCO and bitumen)**

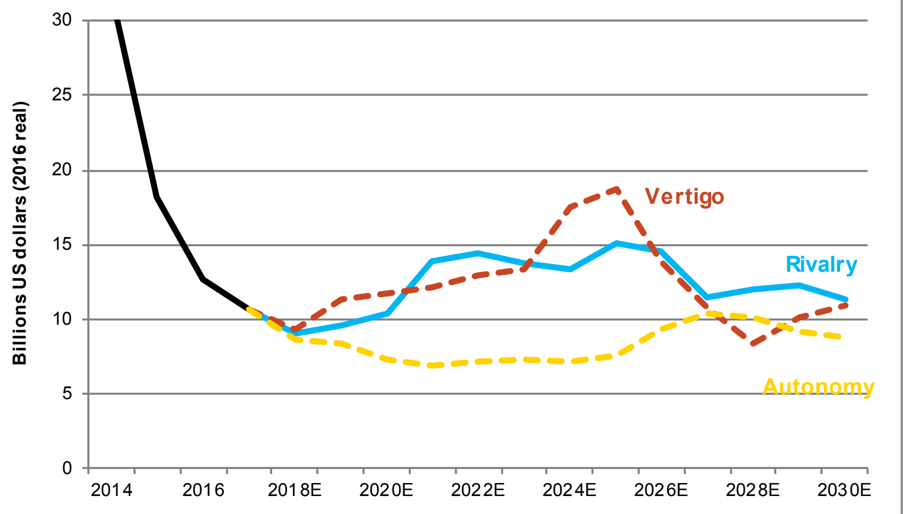



Source: IHS Markit

capital to building new facilities. Yet, while investment levels recover, they remain well below the heights of 2014 for the remainder of our outlook. This reduces the trajectory of production growth in the 2020s from that of the 2010s. All told, oil sands output expands nearly 1.4 MMb/d in 2017–30—with 26% of this growth from projects already in ramp-up or under construction today, 13% from efficiency gains, and the remainder from projects yet to be sanctioned (the vast majority of those being expansions).

Figure 5

Oil sands capital investment




Note: E = estimated.
Source: CAPP, IHS Markit

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**Autonomy** is characterized by a period of sustained lower prices. Global oil demand falls short of expectations, setting the stage for a protracted period of lower prices through the mid-2020s. Lower prices shrink upstream investment in the oil sands (and elsewhere) more than in the other IHS Markit scenarios. Investments that are made aim to increase the operational efficiency of existing facilities, and in only the most attractive projects. Just like in Rivalry, the oil sands move into a period of reduced investment as uncertainties such as market access by pipeline and the stringency of carbon policies weigh on investment. However, the impact is particularly acute and sustained with prices remaining entrenched around $40/bbl WTI into the early part of the next decade. Oil sands projects that are near completion today are brought online, but new investments are put on hold. Through the worst of the price trough (from 2018 to 2022), a handful of less efficient, smaller-scale oil sands operations eventually succumb to the protracted price environment and shutter. Yet, most oil sands production continues as producers manage to continue to deliver efficiency gains. Upstream costs continue to deflate, and more oil is produced from existing operations offsetting what shut-ins do occur. When prices do finally begin to strengthen in the mid-2020s, the upshot of nearly a decade of focus on operational efficiency allows projects to advance for less. Beginning in the mid-2020s, oil sands investment begins to increase—first in efforts to further enhance the efficiency of existing operations and then later to expand existing facilities. This allows production growth to slowly reemerge nearly a decade after the price collapse began.

Oil sands investment levels in Autonomy are the lowest of the three scenarios. Investment remains just above the low point in Rivalry until the mid-2020s and below $10 billion per year for nearly a decade from 2018 to 2027. This is partly because of reduced cash flows of oil sands producers but also because when investments in new projects are made, they come at lower costs than other scenarios. Production growth is correspondingly the lowest in Autonomy. From 2017 to 2030, oil sands production rises over 700,000 b/d. About 70% of this growth comes from existing projects and projects under construction or recently completed, including productivity gains, which account for one-quarter of overall production gains. The remaining growth comes from project expansions that begin to gradually emerge around 2026. If oil sands production declined at the global aggregate rate for conventional fields—an annual average of roughly 2.5% in 2016—total oil sands production in 2030 would be the same as in 2017.[21] These numbers underline the importance of the "no decline" characteristic of oil sands projects.

**Vertigo** exemplifies an uncertain world, where risk and economic volatility weigh on investment decisions globally. The oil price cycle is collapsed, and price swings are dramatic but short lived. A surge in demand growth helps drive oil prices near $90/bbl in real terms in 2018. Yet oil sands companies are hesitant to respond, facing short-term market uncertainties such as crude by rail, and are eager to rebuild their balance sheets. Nonetheless, improved cash flow from

21. Based on 2016 stock of global conventional fields as estimated in the 2017 IHS Markit Annual Strategic Workshop.

higher prices eventually encourages some producers to accelerate projects planned for a more distant date. But almost as soon as these projects are sanctioned, they are caught in the rapidly falling price cycle that emerges almost as quickly as prices rose. To be sure, the magnitude of the 2019–20 price decline is not severe enough to jeopardize projects under construction, and projects continue to completion, but it causes some hesitation in additional project sanctions. As prices begin to recover again in 2021–22, balance sheets of oil sands producers begin to heal, and, again, higher prices stimulate greater investment. But the price collapse toward the end of the decade is debilitating, with many producers having to produce at a loss for the better part of 2028 (when the oil price falls below $20/bbl WTI in real terms on an annual average basis). A number of smaller oil sands projects are caught out, given the severity of this price drop. Investment is cut and many projects under construction are indefinitely deferred; some are outright canceled, and a number of operations, some nearing the end of their natural life, are shuttered early.

In total, oil sands output expands over 1.2 MMb/d from 2017 to 2030. This is less than in Rivalry, with volatility slowing investment decisions and reducing the number of projects in operation at the end of 2030. Overall investment levels between 2017 and 2030 are similar to Rivalry, with price volatility contributing to periods of more rapid cost inflation and thus higher required investment levels. New capital and sustained investment average just over $12 billion per year from 2017 to 2030—almost identical to Rivalry but with more wild movements (as shown in Figure 5), from lows just over $8 billion to highs of almost $19 billion. Notably, even in Vertigo, investment levels never exceed the highs of 2014. In this scenario, the drivers of growth are relatively balanced, with new projects fueling about half of overall growth. The remaining 650,000 b/d of anticipated production comes from recently completed projects and projects in construction today, with nearly half of this gain influenced by productivity improvements particularly related to the 2028 price collapse.

## Part 5: Conclusion

Oil sands projects require investors to make large out-of-pocket, up-front investments for two years or more. In exchange, they receive an incredibly long, relatively stable oil-producing asset that can generate annuity-style cash flow. The up-front, out-of-pocket investment required to bring a new oil sands project creates a hurdle that has challenged investors since the onset of the price collapse.

All signs point to the ongoing slowdown in the oil sands continuing to play out, at least to the end of this decade. Every year since 2014, investment has declined. The long lead time associated with bringing a new oil sands project online has allowed the oil sands to continue to grow since the price collapse. However, with less than a handful of projects sanctioned since the downturn, these same lead times point to a period of reduced supply additions.

Since the oil price crash, oil sands producers have renewed their focus on improving their competitiveness by improving operational efficiency—and thus driving production higher from existing projects and at lower cost. However, so too have producers globally, and though oil prices have improved, future investments in the oil sands remain clouded, not only by the future trajectory of global oil prices but also by a number of unique uncertainties the oil sands face.

The future of the oil sands is inextricably linked to the course of the future oil price. In all three IHS Markit energy scenarios, a few commonalities are true. Oil sands facilities, once operational, are largely unresponsive to the oil price—with production neither ramping up nor ramping down materially. Oil sands production is more akin to base-load power generation, but for the oil market. The long-flat production profile of oil sands assets makes a future without growth difficult to see—and a future with less output than today even more remote. Even in the IHS Markit scenario with the lowest annual average oil price, oil sands production does rise, albeit more modestly, and is more reliant on further efficiency gains from existing projects. Yet, in each of the three scenarios considered in this report, including the two that depict higher annual average oil prices than today, oil sands investment and growth remain lower and slower than in recent history.

 

## Report participants and reviewers

IHS Markit hosted a focus group meeting in Ottawa, Ontario, Canada, on 7 June 2017 to provide an opportunity for stakeholders to come together and discuss the future of transportation fuels. A number of participants also 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 Markit is exclusively responsible for the content of this report.

- Alberta Innovates
- Alberta Department of Energy
- Alberta School of Business, University of Alberta
- Cenovus Energy
- Ecofiscal Commission
- Imperial
- Natural Resources Canada
- The International Emissions Trading Association (IETA)
- Suncor Energy
- Environment and Climate Change Canada
- TransCanada Corporation

## IHS Markit team

**Kevin Birn,** Senior Director, IHS Markit, is based in Calgary and is part of the IHS Markit North American Crude Oil Markets team, leads the IHS Markit Oil Sands Dialogue, and is responsible for a team of oil market analysts focused on western Canada. Mr. Birn has authored over 40 reports associated with the development of the Canadian oil sands. His expertise includes Canadian oil sands development, oil sands cost and competitiveness, crude oil markets, crude oil transportation logistics, GHG intensity of crude oil, and Canadian energy and climate policy. Mr. Birn has contributed to numerous government and international collaborative research efforts including the 2011 National Petroleum Council report *Prudent Development of Natural Gas & Oil Resources* for the US secretary of energy. Prior to joining IHS Markit, Mr. Birn was a senior economist with the Government of Canada and a partner in a software firm. Mr. Birn holds undergraduate and graduate degrees from the University of Alberta.

**Jeff Meyer,** Director, IHS Markit, focuses on the global oil market and industry trends. Prior to joining IHS Markit, 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.

**Karen Kuang,** Principal Analyst, IHS Markit, is a part of the North American Crude Oil Markets team. Her expertise includes modeling and analysis of crude oil and refined petroleum product supply/demand, price forecasting, and transportation costs. She is the primary modeling resource for the North American Crude Oil Market and Refined Product Market research/consulting teams. Ms. Kuang has participated in numerous oil, natural gas, and NGLs research and consulting projects. Ms. Kuang holds an MS from China University of Geosciences and an MBA from the University of Calgary.

**Patrick Smith,** Research Analyst, IHS Markit, is part of the North American Crude Oil Markets team. His responsibilities include the delivery of market research concerning supply/demand analysis, price forecasting, transportation, and overall policy and geopolitical issues that influence oil markets. Prior to joining IHS Markit, Mr. Smith was an energy market analyst at Cenovus Energy in its Market Fundamentals and Hedging department. Mr. Smith holds a BComm from Dalhousie University.

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# Canadian Oil Sands Face US GHG Policy Uncertainty

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## About This Report

**Purpose.** This IHS CERA Special Report offers an independent assessment of the potential impact of evolving US greenhouse gas (GHG) policy on crude oil markets, particularly the Canadian oil sands. The outcome of the policy debate will help to shape the economic and political playing field for the oil sands industry and could have a broader impact on oil supply and energy security in the United States and beyond.

**Context.** This is the final in a series of reports from the IHS CERA Canadian Oil Sands Energy Dialogue 2010. 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. The 2010 Dialogue program and associated reports cover four oil sands topics:

- The Role of Canadian Oil Sands in US Oil Supply
- Oil Sands, GHG, and US Oil Supply: Getting the Numbers Right
- Oil Sands Technology: Past, Present, Future
- Canadian Oil Sands Face US GHG Policy Uncertainty

These reports and IHS CERA's 2009 Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance* can be downloaded at www2.cera.com\oilsandsdialogue.

**Methodology.** This report includes multistakeholder input from a focus group meeting held in Washington, DC, on November 18, 2010, 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 end of report for a list of participants and the IHS CERA team).

**Structure.** Following the Summary of Key Insights, this report has three major sections:

**Part I: Introduction.** What US policies—both existing and possibly forthcoming—could reduce GHG emissions from transport? What do Canadian oil sands have to do with US GHG policy?

**Part II: Reducing US GHG Emissions.** What is the status of each policy? How could each bring about a reduction in GHG emissions? What are the challenges and potential implications of each?

**Part III: Conclusion.** How much could each policy, or a combination of these policies, reduce GHG emissions and consequently oil demand? How would oil from the oil sands, in particular, be affected by such a policy or policies?

We welcome your feedback regarding this IHS CERA report. Please feel free to e-mail us at info@ihscera.com and reference the title of this report in your message.

For clients with access to **IHSCERA.com,** the following features related to this report may be available online: downloadable data (excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

# CANADIAN OIL SANDS FACE US GHG POLICY UNCERTAINTY

## SUMMARY OF KEY INSIGHTS OF IHS CERA'S ANALYSIS


Policies are being developed and implemented in the United States that aim to reduce greenhouse gas (GHG) emissions from the transportation sector—the source of one third of US emissions. The future course of US GHG policy can influence crude oil demand, supply, and cost. Consequently the outcome of the policy debate will also shape the development of the oil sands—perhaps even more so than other sources of oil supply.

**Policies that aim to reduce transportation GHG emissions vary in their potential to reduce GHG emissions and oil demand. They also vary in the likelihood that they will be implemented as planned.** A patchwork of regional and national GHG rules is in development; yet many policies are expected to fall short of their initial targets. Only the federal vehicle fuel economy rules specifically target emissions from vehicle tailpipes—the source of 70 to 80 percent of the emissions from transportation fuels. At present this initiative has the highest potential impact on US GHG emissions and oil demand.

**GHG policies have the potential to accelerate the long-term trend of flat to slightly declining US petroleum-based liquid fuel demand. At the same time supply from the Canadian oil sands is increasing and will likely double in the next decade.** By 2030, in IHS CERA's expected policy case, US petroleum demand is slightly below 18 million barrels per day (mbd) (not including biofuels), compared with 18 mbd in 2010. In our stretch case policies overcome implementation hurdles and achieve difficult mandates, and petroleum-only demand drops to 16 mbd by 2030. Either way the United States remains one of the world's top crude oil destinations—a market large enough to absorb all oil sands growth.

**Some US GHG policies, if adopted on a nationwide scale or by states, could disproportionately raise the cost of oil sands development and lower its competitiveness compared to other oil supply options. Uncertainty about the final effects of US GHG policies is already adding risk to billions of dollars in oil sands investments.** One such policy is California's Low Carbon Fuel Standard (LCFS), which would require fuel suppliers to use a greater amount of low-carbon alternative fuels (such as biofuels, electricity, or natural gas) to offset the higher carbon-intensity of oil sands crudes. Also cap-and-trade or other carbon price mechanisms have the potential to disproportionately affect oil sands; if US policy does not account for carbon costs already incurred in other jurisdictions, the same carbon emissions could be paid for multiple times—penalizing jurisdictions (such as Canada) that have carbon policies and rewarding those that do not.

# PART I: INTRODUCTION

## BET BIG OR WAIT FOR ANSWERS? WHAT UNCERTAIN US GREENHOUSE GAS POLICIES MAY MEAN FOR THE CANADIAN OIL SANDS

A multibillion-dollar investment decision is not taken lightly. Large capital investments in any industry are made in the face of risks, and the energy industry is certainly no exception. Indeed a volatile oil price that has swung from around $10 to more than $140 per barrel in the past dozen years illustrates one high-profile risk. There are, of course, others. Will demand and supply patterns change abruptly, as they have in the past? Will new technology or competitors alter the playing field? Energy companies have operated in this environment for many decades and know it well. But today there is a complex and increasingly perplexing factor, and the outcome will affect not only energy companies, but also consumers and governments: the future course of US GHG policy.

The matter of GHG emissions is not new. For years it has been a part of the policy debate at many levels of government. And investment decisions have long been influenced by the multiple societal dimensions of energy use, including environmental effects, fueling economic growth, and energy security concerns. Finding the right balance remains a critical path for investment decisions. So the matter of GHG limits—and of environmental quality overall—did not materialize overnight. But what makes today's investment and regulatory environment increasingly fraught with risk is the patchwork of regional and national GHG policies combined with questions concerning their political durability. What if billions of dollars are invested based on a particular policy outcome, but then that policy is materially affected after the next election cycle or by a different government jurisdiction? The uncertain path of GHG policy is a political risk in North America for energy companies.

What do Canadian oil sands have to do with US GHG policy? The Canadian oil sands are one of the most important energy investment destinations in the world. Growth in oil sands production has made Canada by far the largest source of oil imported into the United States. In the first three quarters of 2010 total Canadian oil imports (oil sands, conventional oil, and refined products) averaged 2.5 mbd—nearly double that the number two supplier, Mexico.[1] Canadian oil sands are also energy intensive. Life-cycle GHG emissions from fuels derived wholly from oil sands range from 5 to 15 percent higher than the average crude processed in the United States.[2] The oil sands are not alone in this regard. Some crude oil from Venezuela, Nigeria, and some US domestic crudes are in the same range. However, the oil sands' proximity to the United States, the relative accessibility of oil sands data and operations, and expectations of ongoing supply growth generate a higher profile in the environmental arena than many other sources of supply. The United States is, for now, virtually the only market for Canadian oil sands, so US GHG policy, including that of

1. US crude oil imports include Canadian conventional supply estimated at 0.9 mbd, oil sands supply near 1.1 mbd, and refined products of 0.5 mbd.
2. Life-cycle emissions are calculated on a well-to-wheels basis (including emission from fuel combustion in the vehicle). Most GHG emissions are related to combustion—the gasoline being consumed in an engine. The amount of energy used to extract, process, and refine oil sands—the well-to–retail pump portion of life-cycle emissions—results in GHG emissions that are 1.3 to 1.6 times higher than the average crude refined in the United States. Source: IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right*.

Note: Prices are in US dollars unless otherwise indicated.

individual states, will shape the future role of the oil sands in the fabric of North American energy security, economic growth, and environmental outcomes.[1]

## PERPETUAL POLICY MOTION?

The potential impact of US GHG policy is profound across a range of economic, security, and environmental dimensions. The impact is not just simply related to the implications of a particular policy being implemented or proposed. The mix and uncertain durability of measures across a range of jurisdictions are creating additional layers of risk. It this state of potential "perpetual policy motion" that could conceivably be as harmful to interests across the political and environmental spectrum as any specific but enduring policy measure.

## NO GREEN OR RED LIGHT, BUT YELLOW

Momentum toward or away from a national US GHG policy has been buffeted by changing political winds. At times in recent years it appeared that momentum was building toward greater clarity in US GHG policies. But this momentum dissipated as the Great Recession and stubbornly high unemployment led to a shift in priorities, at least in the national legislative arena. At the same time measures in other branches and levels of government have been implemented or are progressing toward consideration or adoption. Yet even in some of these cases, there is no certainty that the measures will be likely to endure election cycles. The net effect is neither a red nor a green light toward a clear and widely supported GHG policy in the United States—just a bright yellow light of caution.

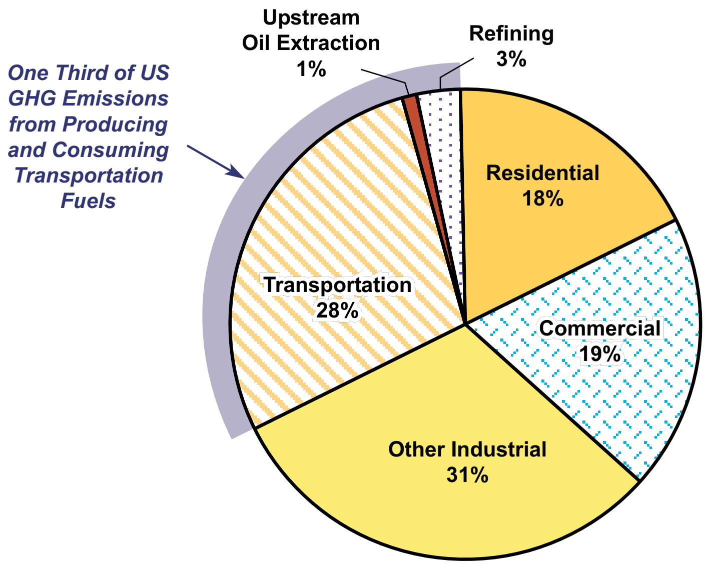
## CONNECTIONS: GHG EMISSIONS, ENERGY USE, TRANSPORTATION, OIL, AND THE OIL SANDS

GHG policies are inextricably linked to energy use. Producing and refining oil accounts for about 5 percent of US GHG emissions, while fueling the cars, trucks, planes, and trains to transport people and goods represents 28 percent of total US GHG emissions (see Figure 1). Since petroleum constitutes 95 percent of US transportation energy, the future course of GHG policy could shape the future course of oil demand, supply, and cost.[2] Consequently, this will also shape the oil sands—perhaps even more so than other sources of oil supply.[3] Although the political debate about oil sands in the United States has tended in recent years to focus more on carbon, greater uncertainty in the Middle East is likely to elevate energy security as a concern and thus the importance of oil sands as a large-scale, growing, secure North American resource.

1. In the first three quarters of 2010, less than 2 percent of oil sands production was exported to non-US destinations. Source: NEB.
2. The nonpetroleum part is from biofuels.
3. This is due to the higher carbon intensity of oil sands and its sole dependence on the US market.

**Figure 1**

**Breakdown of US GHG Emissions**




Source: EIA and IHS CERA (estimated upstream and refining).
10207-1

## REPORT STRUCTURE

Part II of this report explores a number of US policies, in various stages of implementation, all targeting reductions in US GHG emissions from transport. Many of these policies are still uncertain, and some are not likely to be implemented in their current form—or perhaps not at all. This report serves as a framework for understanding the current GHG policy playing field and assesses the potential implications for the oil sands industry, including repercussions on energy security, the economy, and environmental outcomes.

# PART II: REDUCING US TRANSPORT EMISSIONS

A number of policies being considered or implemented could affect GHG emissions from transport and consequently influence oil demand. The four main policy areas are[1]

- Policy Area One: US Environmental Protection Agency Regulations.
- Policy Area Two: Renewable Fuel Standard. This is a US federal mandate requiring the US transportation sector to use a minimum volume of biofuels.
- Policy Area Three: Carbon price. These include cap-and-trade schemes or a carbon tax. Such programs are designed to reduce GHG emissions by attributing an economic cost to emitting carbon dioxide ($CO_2$).
- Policy Area Four: Low Carbon Fuel Standards. The goal of LCFS is to displace petroleum in the transportation sector with alternative fuels that have lower GHG emissions.

In Part II we describe these policy areas and assess of their potential impact on transport and oil.

## POLICY AREA ONE: US ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

In addition to regulating conventional pollutants (including pollutants responsible for acid rain and ozone depletion), the US Environmental Protection Agency (EPA) has begun to regulate GHG emissions through the Clean Air Act. Movement toward regulation began in 2007, when the US Supreme Court upheld EPA's authority to regulate GHG emissions under the existing Clean Air Act, which was originally enacted to control air pollution. In 2010, EPA outlined two paths for regulating GHG emissions: the first to reduce GHG emissions from large stationary sources (such as power plants and refineries); and the second to reduce GHG emissions from mobile sources, specifically light- and heavy-duty vehicles. The latter regulations have taken the form of higher fuel economy standards for vehicles.

EPA's role in reducing GHG emissions has been controversial. Some members of US Congress are moving forward with initiatives to stop or slow EPA's regulation of GHGs, arguing that these regulations could harm the economy and are outside the agency's remit. In addition some states have initiated legal challenges, questioning EPA's authority in this regard.

### EPA: Stationary Source Regulations and GHG Reductions

New EPA regulations for stationary sources came into effect on January 2, 2011. For now, the stationary source rules target large, concentrated, industrial emissions sources. The sources relevant to the transportation sector, oil refineries, are responsible for 3 percent of all GHG emissions in the United States. The new regulations stipulate that any refinery that is newly built or that undergoes major modifications must deploy the best available control

1. Policy areas are numbered for ease of reference and to facilitate the reading of this report. They are not intended as a ranking of any sort.

technology (BACT) to reduce GHG emissions. BACT, however, is a concept that is open to interpretation. Currently the EPA interprets BACT as technology that improves energy efficiency (thus lowering GHG emissions). In the future BACT could include currently high-cost technologies, such as carbon capture and storage (CCS), as such technologies mature and costs come down. The definition of BACT is likely to evolve slowly.

In addition to existing BACT regulations, EPA kicked off a new round of GHG regulations in December 2010. Under a settlement agreement with several environmental nongovernmental organizations and state governments, EPA agreed to develop new source performance standards (NSPS) for both power plants and refineries. For refineries we expect that final NSPS rules will not be adopted until after 2012. Despite the name, NSPS would apply to both new and existing sources, and unlike BACT requirements, NSPS could be applied independently of whether a plant is undergoing major modification. EPA has yet to release a draft rule for NSPS, and a wide range of outcomes is possible. For example EPA could use NSPS to set output-based performance standards, e.g., GHG per unit of output, and some have even suggested this provision could be used to develop limited regional cap-and-trade programs. Although it is too early to know for certain, NSPS requirements could ultimately prove more challenging than the current BACT requirements for GHG emissions.

### *Limited Emission Reductions from Refinery Efficiency Alone*

For oil refiners it makes economic sense to reduce energy consumption, since energy is a key input cost. This in turn reduces GHG emissions—a win-win scenario. Over the past 18 years, on average the energy required to refine a barrel of crude oil by US refineries has declined 8 percent. Still, for the most sophisticated and large refineries, greater efficiency improvements could be possible. Some of the world's most advanced refineries have targeted energy efficiency improvements of around 10 percent per decade. Considering this, refiners could potentially reduce their energy consumption (and hence GHG emissions) between 4 to 10 percent (assuming plantwide improvements). But this would be a best-case, maximum efficiency improvement scenario. If this best-case scenario could be achieved, it would reduce GHG emissions by about 19 million metric tons (mt) of carbon dioxide equivalent ($CO_2e$) per year from the refining sector—roughly equivalent to the annual emissions of four to five average-size coal plants.[1]

### *Challenges in Implementation: Applying BACT*

The Clean Air Act is not new—it was signed in 1970 and has been used to regulate pollutants such as particulate matter, carbon monoxide, and sulfur dioxide. What is new is applying the act to the regulation of GHG emissions. Apart from legislative and legal challenges, the most significant implementation hurdle is an uncertain interpretation of BACT (along with EPA's determination on NSPS). In EPA's regulation of other pollutants, what constitutes BACT has varied from state to state and from project to project. This does not mean that the rule cannot be enforced; the Clean Air Act has used BACT for decades. But it does suggest that

1. All coal plant–equivalent emissions calculations in this report are based on the EPA Calculator (http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results). The calculator assumes in 2005 there were 1,973,625,358 tons of $CO_2$ emitted from power plants whose primary source of fuel was coal. In 2005 a total of 465 power plants used coal to generate at least 95 percent of their electricity.

implementation of BACT for GHG emissions will likely be uneven. It also suggests that the extent of potential GHG reductions will be much smaller than the industrywide, best-case, maximum efficiency improvement scenario above.

*Implications for Oil and the Oil Sands: A Possible Disadvantage*

Assuming that EPA's BACT guidelines for refiners continue to focus on energy efficiency improvements, crude oil with higher-than-average GHG life-cycle emissions, such as from the Canadian oil sands, should not be at a significant disadvantage to other crudes. Although the rule is expected to increase costs for refiners, it is not expected to have a significant effect on oil demand. The mandate addresses efficiency improvements for producing fuels, not consuming them.

Depending on the final definition of NSPS as a performance standard, specific implications for higher carbon crudes are possible. For example, if the performance standard becomes GHG per barrel of refined product, and refining oil sands crudes result in higher emission intensities, there could be an incentive to avoid these crudes.

## EPA: Mobile Source Transportation Emission Regulations and GHG Reductions

EPA aims to reduce GHG emissions from light-duty motor vehicles and medium- and heavy-duty trucks. In April 2010, EPA and Department of Transportation (DOT) finalized the Corporate Average Fuel Economy (CAFE) standards for light-duty vehicles.[1] The rules stipulate all new light-duty vehicles must average 35 miles per gallon (mpg) by 2016—nearly a 30 percent improvement over today's average efficiency standard of about 27.5 mpg for new cars and trucks. The EPA and DOT are considering more stringent CAFE standards by 2025—potentially between 47 and 62 mpg.

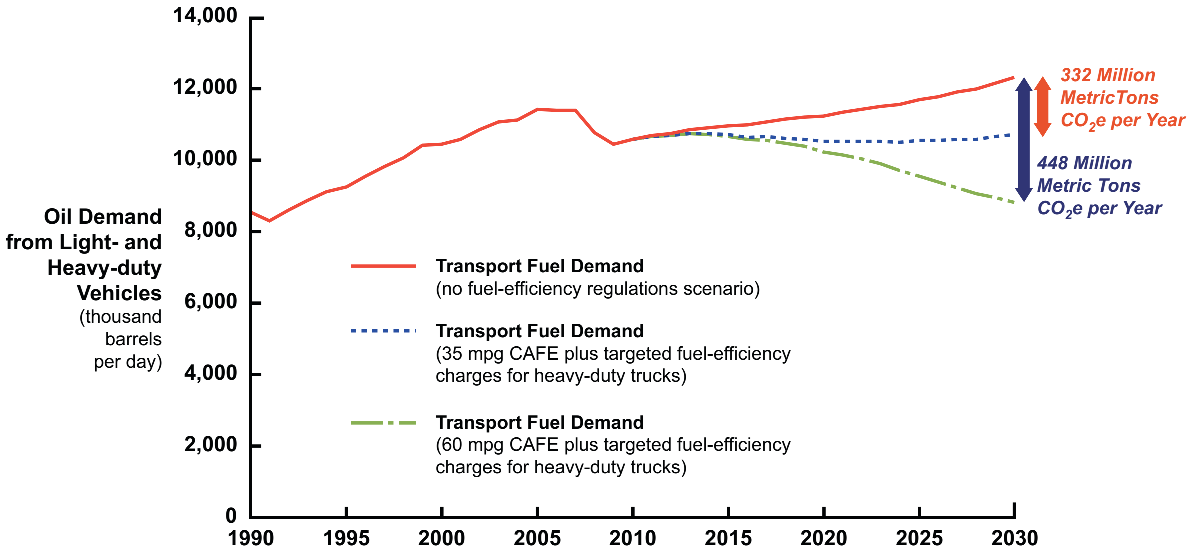
For medium-duty and heavy-duty trucks—including everything from large pickup trucks and vans to long-distance buses and semi-haulers—EPA and DOT are developing fuel-efficiency standards for the first time. These rules are planned to start in 2014 with full implementation by 2018. The new fuel efficiency standards are expected to be finalized by August 2011, and improvements as high as 25 percent for some vehicle classes are being targeted.

Since 70 to 80 percent of well-to-wheels emissions from producing and consuming transportation fuels comes from consuming fuel in the vehicle, regulations targeting fuel economy (how far a vehicle can travel on a given amount of fuel) can significantly decrease GHG emissions from transportation. Under the current rules (35 mpg for new light-duty vehicles and targeted fuel efficiency changes for heavy-duty trucks), GHG emissions would decline 332 mt $CO_2e$ per year by 2030 compared with a scenario with no fuel efficiency changes. These reductions are equivalent to the annual emissions of 86 coal plants. In the stretch case GHG emissions decline 448 mt $CO_2e$ per year by 2030—equivalent to the annual emissions of 116 coal plants (see Figure 2).[2]

1. The standards are set by EPA and the National Highway Traffic Safety Administration (NHTSA), which is a division of DOT.
2. EPA's stretch case, or higher-end proposal, is assumed to be 60 mpg by 2025 for light-duty vehicles and targeted fuel efficiency changes for heavy-duty trucks.

**Figure 2**

**EPA Mobile Source Transportation Emissions: Effect on Oil Demand and GHG Emissions per Year**




Source: Historical data from EIA, projections from IHS CERA.
10207-3

## *Challenges in Implementation: Vehicle Technology Development Required to Meet Targets*

The light-duty regulations for 2016 and beyond are likely to require deployment of new technologies by automakers. By contrast the medium- and heavy-duty truck fuel economy proposal aims to leverage existing technology to improve fuel efficiency.

Automakers can comply with light-duty CAFE standards in a number of ways. Likely options will include a mix of the following actions:

- producing electric vehicles (EVs)
- dramatically improving efficiency of combustion engines
- producing smaller and lighter vehicles

The pace of development of new, potentially more expensive technologies along with changes in consumers' preferences will be critical in defining the future vehicle mix.

In 2010 virtually all US light-duty vehicles were based on combustion engine technology. In 2011 for first time commercial numbers of battery electric vehicles (BEVs) or plug-in hybrid electric vehicles (PHEVs) are being offered by major auto manufactures in the United

States.[1] Sales of BEVs and PHEVs in 2011 are expected to be around 18,000 vehicles in the United States—still a small percentage of close to 13 million light-duty vehicles projected to be sold in 2011 or the over 250 million already on the road.

Assuming the introduction of a high CAFE target for 2025 (60 mpg or higher), alternative vehicle technologies must advance quickly; the costs have to come down, or it will be difficult to entice consumers to purchase these more expensive vehicles. Because of the significant hurdles to meeting the 2025 stretch case goal (above 60 mpg), we expect that EPA and DOT will issue a lower 2025 target. A decision is likely in the next year or two. Congressional opposition is another potential headwind against an aggressive 2025 target. Considering the potential magnitude of the 2025 targets, it's possible that legislators would try to reduce the level or block altogether the adoption of a stringent target.

*Implications for Oil and the Oil Sands: Same for All Crudes*

EPA's current 35 mpg light-duty and targeted heavy-duty regulations will reduce US oil demand by more than 1.6 mbd by 2030 compared with a scenario with no fuel economy change.[2] In a stretch case, where light-duty vehicles reach 60 mpg by 2025 and targeted heavy-duty regulations are in force, US oil demand would be 3.5 mbd lower by 2030. Comparing the heavy-duty and light-duty efficiency gains, the light duty is responsible for the majority of the oil demand decline—about 80 percent. Like the EPA stationary source regulations, however, this ruling will affect all crude sources equally and therefore should not result in significant disadvantages for higher-carbon crude sources, such as the Canadian oil sands.

## POLICY AREA TWO: RENEWABLE FUEL STANDARD

### Policy and GHG Reductions under the US Federal Mandate

The RFS2 is a US federal mandate requiring the US transportation sector to use a minimum volume of biofuels each year to 2022. One of the aims of this policy, in addition to reducing dependence on foreign oil and boosting the domestic renewable fuels sector, is to decrease GHG emissions by substituting petroleum with lower-carbon biofuels. Under the current rules 2.35 mbd of biofuels must be consumed by 2022. The program was established in 2005 as RFS and updated with higher targets in 2007, which has become known as RFS2. RFS2 also introduced specific categories of renewable fuels (renewable fuel, advanced biofuel, cellulosic biofuel, and biomass diesel), setting volume and GHG emission targets for each type. To count as a renewable fuel under RFS2, the well-to-wheels GHG emissions of the biofuel must be less than the petroleum it is replacing, by a specific threshold.[3] Although

1. PHEVs have an all-electric range large enough to handle most day-to-day driving, with a backup conventional fuel tank to ensure a range as great or greater than that of a gasoline vehicle. PHEVs do not include "conventional" hybrids, such as the Toyota Prius, which is classified as a combustion engine vehicle—albeit a higher-efficiency one. BEVs are all-electric vehicles.
2. This scenario assumes that vehicle economy is the only static variable; other factors including vehicle miles driven and total number of vehicles still continue to grow.
3. For instance EPA stipulates that total emissions for corn-based ethanol (produced from newly constructed biorefineries) must be 20 percent lower than that of petroleum gasoline. Other biofuels must achieve even higher targets: cellulosic ethanol must have 60 percent lower GHG emissions than petroleum gasoline.

the program calls for biofuels in general, the vast majority of the biofuels consumed in the United States is ethanol, a substitute for gasoline.

The EPA anticipates that even without the RFS2, the United States would consume 0.9 mbd of biofuels by 2022. Consequently if the RPS2 rule is achieved, it would result in 1.45 mbd of additional biofuel consumption compared with a “no policy” case.[1] EPA estimates that by 2022 GHG emissions will be 138 mt per year lower than without the policy—or equal to the annual emissions of 32 coal-fired power plants. Assuming that the additional biofuels are from conventional ethanol (which has about one-third lower energy content than the same volume of petroleum fuel), this would mean about 1 mbd of lost petroleum-based oil demand.[2]

However, given the challenges in supplying and consuming large volumes of biofuels (see Challenges in Implementation, below), IHS CERA expects that US biofuel consumption will fall well short of the 2022 RFS2 mandate—hitting just 1.3 mbd by 2022. Taking into account EPA’s projection for biofuels consumption with no mandate, the policy results in only 0.4 mbd of additional biofuel consumption by 2022 (over the “no policy” case). Thus we estimate RFS2 will reduce GHG emissions by 20 mt per year—equal to the annual emissions of about 5 coal-fired power plants.[3]

## Challenges in Implementation

Both the suppliers and consumers of biofuels will face challenges in complying with RFS2.

### *Supply Challenges May Change Timeline*

Of the 2.35 mbd of biofuels mandated by 2022, the majority will be from ethanol. The volume of ethanol derived from corn starch—the only commercially viable biofuel in the United States today (with the exception of relatively modest volumes of biodiesel)—is capped near 1 mbd. The remainder, 1.37 mbd, must be from “advanced biofuels” derived from noncorn feedstocks. Of this noncorn portion about 0.33 mbd can be “undifferentiated” advanced biofuels, for example biodiesel or sugarcane-based ethanol (likely sourced from Brazil). The rest, 1 mbd, must be derived from cellulosic feedstock (such as switchgrass, corn stover, or wood chips). Yet cellulosic biofuels are not close to being produced at a commercial scale.[4] Without rapid development and scale-up of cellulosic production, the United States will fall short of the 2022 targets.

1. The biofuels projection (in the absence of RFS2) is based on the Energy Information Administration’s (EIA) 2007 Annual Energy Outlook (AEO)—a forecast created prior to the enactment of EPA’s policy. Source: EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis, February 2010.
2. Owing to the lower energy content, the volume of oil displaced is less than the biofuel volume.
3. IHS CERA assumes that less than 5 percent of 2022 ethanol volume is from the lowest-carbon ethanol—cellulosic. The majority of the ethanol is assumed to be corn based. Most ethanol derived from corn has a 20 percent GHG benefit compared with petroleum gasoline. The lack of very low-carbon ethanol, along with less volume overall, notably reduces GHG emission benefits.
4. Currently no commercial-scale cellulosic biofuels are being produced. Challenges to commercial production include process economics, feedstock availability at large scale, and feedstock and fuel transporting logistics.

*Consumption Challenges with Consumers*

Even if the supply challenges are overcome, it will be a test whether consumers can utilize the ever-higher mandated volumes of ethanol. Although a portion of the ethanol could be seamlessly blended into conventional gasoline (either as 10 or 15 percent ethanol blends with gasoline), given ethanol's corrosive properties a significant volume—more than 1 mbd—would have to be consumed in flex-fuel vehicles (FFVs) that can handle the more corrosive, higher-ethanol blends such as E85 (85 percent ethanol and 15 percent gasoline).[1] Both the sales of FFVs and the development of the infrastructure to distribute the E85 fuel would have to accelerate dramatically. Specifically fueling stations would have to install new tanks and pumps, and consumers would have to buy more FFVs. Even if these logistical hurdles could be overcome, consumers would still have to choose to fill up with E85. Given that E85 has about 25 percent less energy than an E10 blend (and therefore will require more frequent refueling) consumers may balk at purchasing E85 unless it is substantially discounted.

### Implications for Oil and the Oil Sands: No Specific Impact

Given IHS CERA's expectation that biofuel consumption will fall short of EPA's target for 2022—and taking into account the lower energy yield of ethanol compared to gasoline—we expect the RFS2 to lead to a reduction in US petroleum-based oil demand of only 0.3 mbd by 2022 (taking into account EPA's forecast of 0.9 mbd of biofuels consumption by 2022 without the mandate). This is a much more modest amount than the 1 mbd of lost petroleum-based oil demand that results if the mandate's target is achieved. This policy has no specific impact on oil sands.

## POLICY AREA THREE: CARBON PRICE

### Carbon Price Policy and GHG Reductions

Carbon price policies, such as cap-and-trade or carbon tax, are designed to reduce GHG emissions by using market forces—imposing an economic cost for emitting carbon and thus providing carbon emitters an incentive to reduce GHG emissions. A carbon tax requires emitters to pay the government, not unlike a sales tax on goods and services. The cap-and-trade mechanism establishes a maximum limit—or cap—on the amount of emissions that various entities can emit. Entities that emit less than their maximum limit are able to sell or trade their surplus allowance in the form of a carbon credit. A key difference between a carbon tax and cap-and-trade is that the price of carbon under a carbon tax policy is fixed, whereas the price of carbon in a cap-and-trade policy is determined by supply and demand, and thus fluctuates.

1. On October 13, 2010, EPA granted a waiver of the 1990 Clean Air Act, allowing gasoline retailers to sell a fuel mixture that is 15 percent ethanol and 85 percent gasoline by volume (E15), a change from the current maximum of 10 percent ethanol (E10). However, the decision approved E15 only for use in model year 2001 and newer cars and light trucks. It will likely take several years before E15 can be widely commercialized since one third of the US on-road vehicle fleet today was built before 2001.

### *Outlook for a Federal US Carbon Price Policy in the Near Term Has Dimmed Significantly*

From 2009 until the first half of 2010, there were credible prospects for a federal cap-and-trade policy. In June 2009 the House of Representatives passed the Waxman-Markey bill, the centerpiece of which was an economywide cap-and-trade program. But this type of policy never gained serious momentum in the Senate. Many senators were concerned over the cost of such policies and were wary of new legislation that would potentially dampen economic growth. Despite such concerns, some proposals were discussed in the Senate during the previous Congressional Sessions (2009–10), including one that called for a cap-and-trade program that would be limited, at least at first, to the electric utilities sector.[1]

However, prospects for a federal cap-and-trade policy—either economywide or targeting specific industries—have dimmed significantly, and this option now seems unlikely during the current decade. Nonetheless several states have taken it upon themselves to establish a cap-and-trade system. Ten Northeast states—including New York, New Jersey, and Massachusetts—in 2009 set up the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade system for the utility sector. A group of seven US states and four Canadian provinces, working under the umbrella of the Western Climate Initiative (WCI), is developing another regional cap-and-trade system. Although WCI is still moving forward, for some jurisdictions participation is becoming more uncertain.[2] In February 2011 the Midwestern Governors Association (representing 10 states) announced that it is abandoning its 2007 cap-and-trade plan; the states are now focused on "encouraging investment of all kinds, and job generation." Meanwhile California has developed a cap-and-trade program that starts in 2012; transport emissions are added to the program by 2015.

### *Limited GHG Emission Reductions Expected for Transport Sector*

Regarding the use of petroleum-based fuels, a high carbon price is required to change consumer behavior. A $20 per metric ton cost applied across well-to-wheels emissions (from fuel production through to consumption) means a $0.30 per US gallon—or approximate 10 percent—increase from late 2010 prices. Such a modest increase is unlikely to significantly change consumer behavior. We expect that a carbon price in excess of $100 per metric ton is required to incentivize a change in driving patterns and consumer vehicle preferences. However, implementing carbon prices in this range is likely to create political issues for any government; higher energy costs in turn hurt the consumer and voter. For emissions that result from the production of transportation fuels (i.e., oil extraction or refining), a lower carbon price (such as $20 to $30 per metric ton) would incentivize some efficiency improvements, but CCS systems would be needed to bring about larger GHG reductions. As CCS is still a relatively immature technology, a high carbon price (likely in excess of $50 per metric ton) would be necessary to incentivize refiners to consider installing CCS. For

1. Senators John Kerry (D-MA) and Joe Lieberman (I-CT) proposed a "utility first" cap-and-trade program in mid-2010, but they never released the full text of a bill associated with such a proposal.
2. WCI includes Washington, Oregon, California, Arizona, New Mexico, Utah, Montana, British Columbia, Manitoba, Ontario, and Quebec. Thus far only some of these states and provinces have passed the legislation required for the originally planned 2012 start. Recently Arizona and Utah have indicated their intent not to participate in the cap-and-trade element of the WCI. New Mexico's new governor has stated her opposition to a cap-and-trade. In British Columbia the premier supporting the original plan recently resigned.

upstream oil production emissions (which are mostly low pressure, distributed, and dilute) the costs are much higher.

If a US federal carbon price policy were to emerge, what range of carbon costs would be likely? Regulations elsewhere provide indications of the potential price levels. In Europe (with a cap-and-trade program for large emitters since 2005) carbon recently traded between \$15 and \$20 per metric ton. In the province of Alberta, which sets carbon intensity limits for large emitters, a fixed cost of C\$15 per metric ton is charged for $CO_2$ emissions beyond the limit.[1] For RGGI in the Northeast carbon prices have been about \$2 per metric ton, and in California (which has a cap-and-trade program scheduled to start in 2012) there is a price floor of \$10 per metric ton starting in 2012, with controls that try to limit prices below \$40 per metric ton. At these price levels we expect only small GHG reductions by producers and consumers of transportation fuels.

## Challenges in Implementation: Domestic versus Imported Products

Since petroleum fuel is produced in a multistep process—often spanning multiple jurisdictions (countries, states, and provinces)—implementing a carbon price policy has challenges. A critical question is how to account for the out-of-country GHG emissions and policies. For instance for US crude oil imports, emissions from the production process occur in the country of origin, whereas refining emissions occur in the United States. For US refined products imports both production and refining emissions occur outside of the United States—sometimes in multiple countries.

There are two main approaches to account for out-of-country GHG emissions: a "reach back" type policy that accounts for all emissions (including emissions that occur outside of the country) or a policy that applies a carbon price only to GHG emissions originating in the country. The first approach is the most likely to be enacted because it ensures that the domestic petroleum industry is on a level playing field with competitors. If emissions outside the country are not accounted for, there would be an economic incentive to move carbon-intense industrial activities to locations where no carbon price is levied (often termed *carbon leakage*).

### *Charging the Same Carbon Molecule Multiple Times?*

One of key challenges of implementing a "reach back" type policy is to fairly account for out-of-country emissions. Even if exporting countries provide the data to the US government, data quality and transparency is certain to be an issue. Another challenge is how to account for products that come from jurisdictions with existing in-country carbon-price policies. If the imported products have already incurred a carbon cost in their home country, the US "reach back" policy could effectively be charging the same carbon molecule again—penalizing jurisdictions with an in-country carbon policy and rewarding those that do not.

1. The province of Alberta's Specified Gas Emitters Regulation sets an intensity-based performance standard for all facilities emitting more than 100,000 mt of GHG emissions. Regulated facilities are required to reduce their emissions intensity by 12 percent below a 2003–05 baseline. Facilities with emissions that exceed the intensity target can comply by purchasing credits from facilities that are under the standard emissions baseline, purchasing Alberta-based GHG offsets, or paying a C\$15 fee for emissions over the target. The money collected from the fee supports a technology fund for clean energy research; to date more than C\$187 million has been collected.

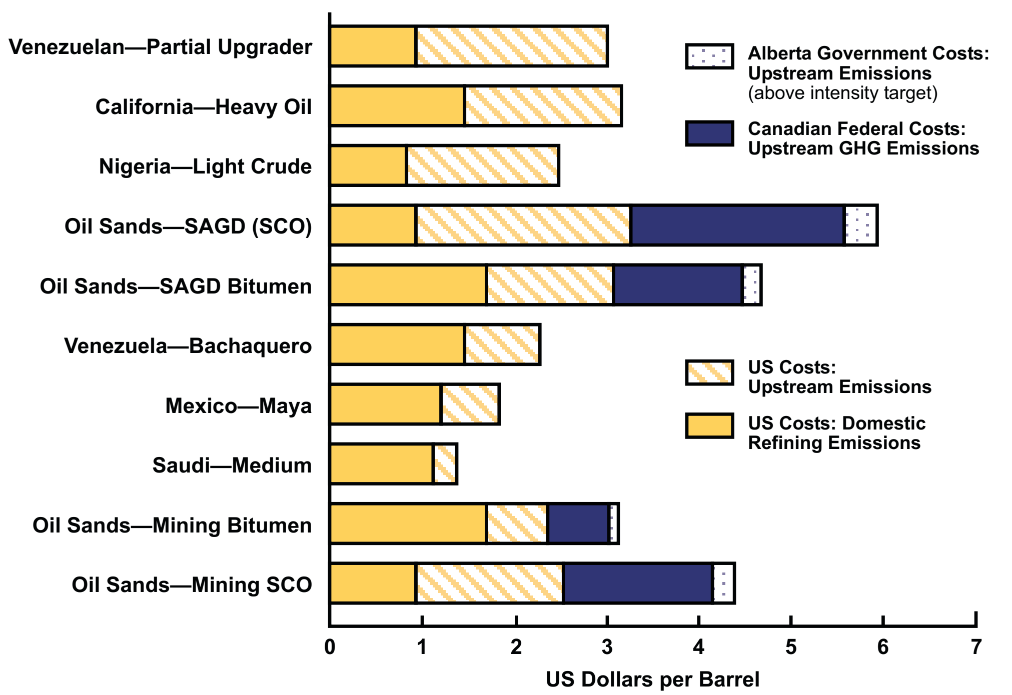
## Implications for Oil and the Oil Sands: Policy Face-off

Although a US federal carbon price policy appears less likely than would have been the case a few years ago, oil sands investments have a long time horizon—in many cases more than 40 years. Therefore during the life of an oil sands investment US adoption of a carbon price cannot be ruled out and could have an impact on the investment. However, if the United States were to adopt a federal or state carbon price policy, it is likely that Canada and Alberta would adopt a similar carbon cost. Yet it is also likely that other US oil suppliers will not have a home-country carbon price policy. In such a situation, if the United States does not account for carbon costs already incurred in Canada and Alberta, oil from oil sands—already a relatively high-cost source of supply—could be at a price disadvantage relative to other crude oils.

Figure 3 compares the effect of a relatively moderate carbon cost—$20 per metric ton—for various sources of crude oil. It illustrates the implications of US carbon-price policy on oil sands compared to other oil supply sources. The figure highlights the potential for oil sands

**Figure 3**

**Illustrative Impact of Costs of Disconnected US and Canadian GHG Carbon Changes**




Source: IHS CERA, assumes $20 per metric ton carbon cost for upstream and refining emissions in United States and Canada, plus Alberta charge of $15 per metric ton on 20 percent of emissions (assumes this amount is beyond intensity target). Scenerio assumes that Canadian carbon costs are not accounted for by US policy. In this case, emissions from Canadian oil sands are charged multiple times—by Canada, Alberta, and the United States.
10207-4

to incur "multiple charging" of the same carbon molecule (upstream emissions are charged three times—by Canada, Alberta, and the United States). Oil sands producers are price takers that must compete with other sources of supply; therefore this "extra carbon cost" could increase costs for oil sands producers, potentially lowering the return on investments and hurting oil sands economics vis-à-vis other crude oil sources.[1] Though this scenario is deemed reasonably unlikely (considering the integrated nature of the Canadian and US economies and expectations that future carbon policy would be harmonized), it highlights the potential impact if carbon price policy is not coordinated among provinces, states, and countries.

## POLICY AREA FOUR: LOW-CARBON FUEL STANDARD

### LCFS Policy and GHG Reductions

The goal of LCFS is to displace petroleum in the transportation sector with alternative fuels that have lower GHG emissions. The metric for measuring "lower emissions" is the well-to-wheels GHG intensity. Current laws call for reductions of up to 10 percent in the well-to-wheels intensity of fuel, phasing in over time. Fuel suppliers are responsible for compliance and must offer lower-carbon fuels for sale.[2]

LCFS are designed to increase consumption of lower-carbon transportation fuels without choosing a "winning" technology. The LCFS is similar to the RFS policy in this regard, because it mandates higher consumption of lower-carbon alternative fuels. However, a key difference is that RFS specifies biofuels for meeting the mandate, whereas LCFS allows any lower-carbon alternative (for instance, biofuels, electricity, hydrogen, or natural gas) to be used. LCFS policies were developed with the goal of filling "gaps" in other policies. Assuming low prices, carbon-price policies are not likely to make significant reductions in the GHG emissions from the transportation sector, and RFS polices do not take into account the potential for alternative vehicle technologies such as PHEVs/BEVs or natural gas vehicles (NGVs) to reduce GHG emissions.

#### *Jurisdictions Adopting LCFS*

Jurisdictions that have adopted LCFS include California, British Columbia, and the European Union. The outlook for a US federal LCFS is unlikely at least in the next decade. However, California's LCFS went into effect on January 12, 2010.[3] The California standard mandates

1. It is possible that oil sands economics will not be materially affected by carbon costs if extra carbon costs are offset by lower taxes or less government take.
2. Achieving a 10 percent reduction in life-cycle emissions solely by offering lower-carbon petroleum-based fuels is very unlikely. For petroleum-based fuels 70 to 80 percent of life-cycle GHG emissions occur in the combustion phase (as exhaust from the vehicle tailpipe). These tailpipe emissions are outside the control of the fuel supplier and are an inevitable result of fuel use. To meet the mandate with petroleum fuels, the 10 percent reduction in *overall* (i.e., well-to-wheels) GHG intensity must occur in the noncombustion, or well-to-retail pump, part of the life cycle. This corresponds to a reduction of approximately one third to one half in well-to-retail pump GHG emissions (those from producing oil, refining it, and distributing it to the retail pump). Even with greater efficiency in production and refining, and CCS, this level of reductions is not practical.
3. There are, however, ongoing lawsuits challenging California's LCFS on the basis of conflict with the Federal Energy Independence and Security Act of 2007 and interference with interstate commerce.

a 10 percent reduction in the GHG intensity of transportation fuels sold in the state by 2020.

In addition to California, several other US states are considering an LCFS. Together the states implementing or considering an LCFS represent 50 percent of the US gasoline market. A group of states in the Northeast and Mid-Atlantic signed a letter of intent at the end of 2009 to jointly review an LCFS policy and plans to develop a draft framework in 2011.[1] A group of ten Midwest states has been working toward an LCFS since 2007.[2] Oregon is expected to release its draft LCFS design this year, and Washington is also discussing adoption of an LCFS.

### *Potential GHG Reductions*

If the targets are met, California estimates that the LCFS would reduce GHG emissions by 15 mt per year by 2020—equivalent to the annual emissions from four coal-fired power plants.[3] However, this calculation assumes that the LCFS is the only policy encouraging the adoption of low-carbon alternative fuels. It does not consider the impact of the federal RFS2 which, if implemented as outlined by the EPA, would also provide GHG reductions for California—in the range of 13.8 mt per year.[4] Since the two policies encourage a transition to lower-carbon alternative fuels, and in the next decade biofuels are the most likely candidates for low-carbon alternatives, the benefits partly overlap. Consequently, the additional emission reductions resulting from California's program are reduced to the difference between the two estimates, or 1.2 mt per year, less than the annual emissions from one coal plant.

## Challenges in Implementation: Substitutions and Sources

For the gasoline pool compliance options could include substituting volumes of petroleum gasoline with corn ethanol, sugarcane ethanol, cellulosic ethanol, electricity, natural gas, or some combination of these fuels.[5]

Factors beyond fuel suppliers' control will make complying with LCFS challenging over the next ten years. Limited availability of low-carbon fuels and limited adoption of vehicles that consume these fuels are the greatest challenges—similar to those faced by RFS2. For instance one option for gasoline pool compliance is blending 50 percent sugarcane ethanol and 50 percent gasoline. Another option is blending 85 percent low-carbon corn ethanol with 15 percent gasoline (i.e., the E85 blend). Yet as is the case with RFS2, distribution of

1. Membership comprises Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.
2. The group is Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio, South Dakota, and Wisconsin.
3. Source: *Climate Change Scoping Plan: A Framework for Change,* California Air Resources Board (CARB), December 2008.
4. California is about 10 percent of the US transportation market, so we credit 10 percent of the total benefits estimated by EPA to California.
5. The initial emissions calculations for California's LCFS estimated that corn-based ethanol (which represents the vast majority of biofuels produced in the United States today) had life-cycle GHG emissions similar to those of petroleum gasoline. Therefore, corn ethanol blending was not a useful strategy to achieve LCFS compliance. However, in November 2010 California revised its emissions estimates for corn-based ethanol to 5 to 20 percent lower than gasoline. Hence now the lowest-carbon sources of corn ethanol can (narrowly) be used to comply with the state's LCFS.

these highly concentrated ethanol blends poses a number of challenges for fuel suppliers and requires FFVs in the fleet to consume the fuel.

Moreover availability of alternative fuels will likely continue to be limited. For California to meet its target with corn ethanol alone, the state would have to consume more ethanol than the United States currently produces. Likewise to meet the target with sugarcane ethanol, more sugarcane ethanol than Brazil produces today is required. Fuel suppliers will almost certainly use a combination of fuels to meet the LCFS mandate, but this would only temper biofuel supply bottlenecks, not alleviate them.

Natural gas and electricity are two additional compliance options with LCFS. Yet EVs are only now becoming available to consumers.[1] In the United States NGV sales have averaged about 1,500 vehicles per year. Limited infrastructure is one reason for slow NGV sales—refueling stations are rare. In IHS CERA's aggressive alternative vehicles scenario—called Meta—PHEVs, EVs, and NGVs displace less than 150,000 barrels per day of US gasoline demand by 2020. Even with a sharp increase in the sales of these alternative vehicles, in a ten-year time frame they will likely provide only modest help in complying with LCFS.

### *Regulation Complexity versus Efficacy*

Regulating based on well-to-wheels emissions estimates requires a trade-off between the complexity of regulation and efficacy. Establishing broad categories of transportation fuels makes regulations simpler for fuel suppliers to comply with and simpler for regulators to enforce. EPA's RFS2 is structured this way; it assigns one emissions value for gasoline and diesel and a handful of broad groupings for biofuels. On the other hand a more granular approach to regulation may be more effective at reducing emissions by providing fuel producers with more incentive to reduce emissions from specific sources. California's LCFS takes this granular approach by establishing numerous categories for petroleum and specific estimates for each biofuel source and process technology. However, having many fuel categories increases the regulation's complexity, requiring suppliers to track the specific fuels that are consumed and to measure emissions for numerous fuel types rather than just a few. Data transparency is another issue in using the granular approach; gathering and verifying GHG emission data for each crude source is a formidable task.

Comparing the two current North American LCFS polices (British Columbia and California) illustrates the trade-offs between complexity and efficacy. The British Columbia mandate takes a simpler approach; it assumes one average well-to-wheels GHG emissions value each for petroleum gasoline and diesel, not differentiating among sources of crude oil used to produce gasoline or diesel. Additionally, it removes a key source of uncertainty in well-to-wheels estimates by excluding indirect emissions. Indirect emissions are difficult to estimate, and as a result there is a wide range of published estimates for well-to-wheels emissions from biofuels (see the box "Data Uncertainty Makes Well-to-wheels a Challenging Basis for Policy").

1. The amount of GHG reduction from using electricity in transportation depends on the source of the electricity. Coal-fired electricity can even increase in life-cycle GHG emissions over gasoline. Using the current California LCFS guidelines, California's average electricity mix (primarily natural gas) would result in about one third of the GHG emissions of a similar gasoline-powered vehicle. Source: Proposed Regulation to Implement the Low Carbon Fuel Standard—Appendix C, March 2009.

The California policy is more complicated. California's LCFS accounts for indirect emissions in its life-cycle emissions estimates for biofuels. It also differentiates among sources of crude oil, establishing an emissions intensity value for a baseline basket of crudes—consisting of major sources of crude oil currently refined in California.[1] Oil sands crudes are not included in this basket of crudes. If a refiner wants to import crude oil from a source not already in the baseline basket—one with upstream GHG emissions exceeding a fixed threshold—it must work with the regulator to establish a specific GHG emissions intensity value for the new crude supply.[2] Some oil sands supply (oil sands extracted using higher GHG-intense methods) would require such treatment.

California's rule—requiring that only new higher-carbon crude sources establish unique GHG intensity values—has been controversial. Canadian officials and industry players have expressed concern that this method discriminates against oil sands crudes compared to California's own high-emissions crude oil, potentially violating provisions of the North American Free Trade Agreement and of the World Trade Organization.

## Implications for Oil and the Oil Sands: Potential Double Effect

The impact of LCFS policies on oil demand is difficult to estimate—it will depend on the alternative fuels used to comply. If very low-carbon alternatives such as yet-to-be developed cellulosic ethanol were available, only about 20 percent of oil demand would be displaced. If corn ethanol were the only available alternative fuel, in theory 85 percent of oil demand

### Data Uncertainty Makes Well-to-wheels a Challenging Basis for Policy

Estimating the well-to-wheels emissions of fuels—whether for crude oils or alternative fuels—is an evolving and still inexact discipline, making these values a challenging basis for policy. Inconsistencies among estimates result from a variety of sources: data (quality, availability, and modeling assumptions), allocation of emissions to the various products produced in the refinery or during oil extraction, and the definition of boundaries for estimating emissions.* For these reasons estimates of well-to-wheels GHG emissions can vary significantly. The carbon emissions reduction benefit that a given policy could be expected to deliver is often a subject of debate. Comparing the renewable fuel emissions estimates in RFS2 with the CARB estimates used in California's LCFS provides an illustration of this variance (see Figure 4).

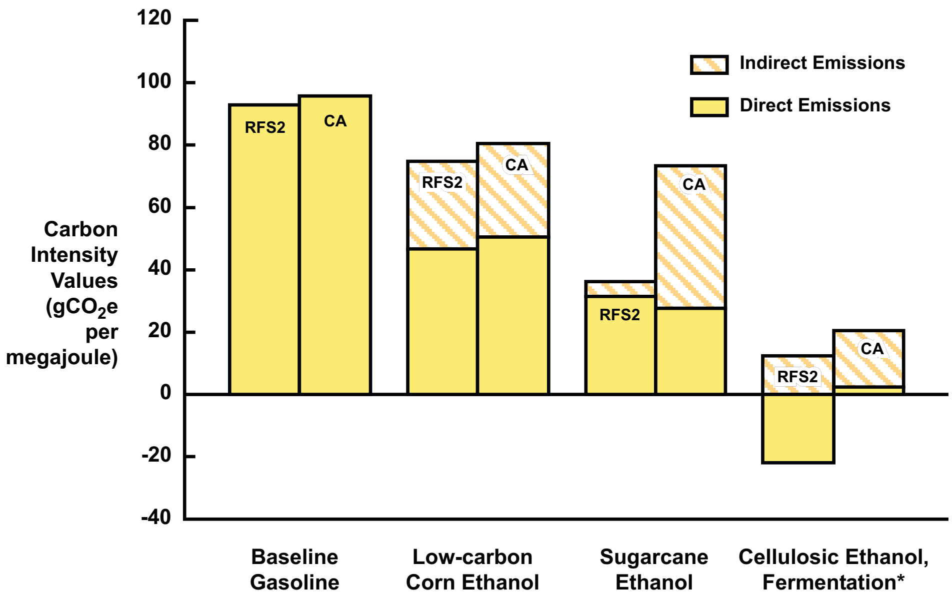
The two policies differ significantly in their estimate of the GHG emissions avoided by switching from petroleum to various alternative fuels. The largest source of difference is in the estimate of indirect land emissions for biofuels—an area of great uncertainty and therefore wide-ranging estimates.

*For a more detailed discussion of the sources of inconsistencies in well-to-wheels GHG emission estimates, refer to the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right.*

1. California's baseline basket of crudes consists of all sources of crude oil that made up 2 percent or more of California refineries' feedstock in 2007. The baseline includes California heavy oil production, an oil source on par with the oil sands in well-to-wheels GHG emissions.
2. Crudes with upstream GHG emissions greater than 15 grams of $CO_2e$ ($gCO_2e$) per megajoule (MJ) cannot use the baseline value. The average crude oil refined in California today has upstream emissions of about 8 $gCO_2e$ per MJ, whereas oil sands crudes vary from about 13 to 19 $gCO_2e$ per MJ.

Figure 4

Renewable Substitutes for Gasoline—
Comparison Between GHG Emission Estimates
for California LCFS and EPA RFS2




Source: EPA RFS Final Rule (March 2010); CARB Feb 2011 proposed look-up tables.
Note: Cellulosic data from CARB proposed regulation (March 2009)
All estimates are well-to-wheel emissions. Low-carbon ethanol assumes
EPA (Gas Fired Dry Mill ) and CARB (California Dry Mill Wet DSG NG).
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could be displaced, although this scenario is not practical because of limited volumes of ethanol. In the next decade, while alternative fuels are in short supply, it is expected that jurisdictions would charge a noncompliance penalty. Assuming the penalty were $20 per metric ton, this equates to about $1 of extra cost per barrel for the average crude.

The extent to which LCFS affects oil sands depends on the style of LCFS chosen. A British Columbia–style policy (one with one well-to-wheels emissions values assigned for all petroleum) would have no implications for oil sands beyond those for oil from other sources. By contrast, a policy mirroring that of California (one that distinguishes among crude oil sources) has specific implications for oil sands. On average wholly derived oil sands products are 10 percent higher in carbon intensity than the average US barrel consumed on a well-to-wheels basis.[1] Therefore, to meet the California mandate, a fuel supplier would have to supply enough alternative fuels to achieve a 10 percent emissions reduction just to bring oil sands to the average crude baseline. Then the supplier would have to supply more alternative fuels to achieve a further 10 percent emissions reduction to meet the mandate. Thus oil sands crudes require about twice as much alternative fuel blending as “average” crudes to comply with the mandate. Given this equation, if oil sands crudes were consumed in notable volumes in California, the volume of oil sands displaced by the policy would be

1. Average emissions from mining bitumen to produce synthetic crude oil and bitumen production.

about two times more than the “average crude.” Likewise, for a noncompliance penalty—the oil sands cost would be double ($20 per metric ton equates to $2 of extra cost per oil sands barrel). The noncompliance penalty could turn into an instance of “multiple-charging” the same carbon molecule. If for example a price for carbon has already been levied (by means of another carbon price policy—either a state, provincial, or federal rule), the LCFS penalty would in effect charge for the same carbon again.

# PART III: CONCLUSION

The policy mechanisms that aim to reduce GHG emissions related to US transportation vary both in their potential to reduce GHG emissions, and therefore oil demand, significantly and in the probability that they will be implemented widely. A mix of policies has already been implemented on a national scale and others only at a state level. Federal policies already implemented include the EPA mobile and stationary GHG emissions regulations and RFS2. However, the federal government has not implemented an LCFS or a price on carbon. California is the only US state with an LCFS in place, and although one state group has implemented a cap-and-trade scheme for the utility sector, outside of California there is no cap-and-trade or carbon tax policy affecting US transport.

## CHALLENGES IN POLICY IMPLEMENTATION

Looking ahead, the implementation of a federal carbon price policy and federal LCFS appears unlikely at least within the next decade. However, it is more likely that new state-level policies could develop. Even policies already established at a federal level—the EPA mobile and stationary regulations and RFS2—will likely face implementation challenges. Under EPA mobile rules automakers must develop and sell potentially more costly vehicle technologies. Moreover if the 2025 fuel efficiency standards (once established by EPA and DOT) are seen by legislators as too strict, they may attempt to block the mandate. With the RFS2 a key challenge is fuel suppliers' ability to meet the targets for using advanced biofuels, both fuel supply and consumption are likely to create bottlenecks.

US policy remains uncertain, with constantly evolving ideas pertaining to climate change and clean energy. Recently the US federal government appears to be shifting priorities toward clean energy investments as opposed to climate change initiatives. Both state and federal governments are attending more to job creation, economic growth, and fiscal prudence. Political considerations will remain important factors shaping US GHG policy. Meaningful carbon reductions often equate to higher energy costs—for the taxpayer, corporation, or consumer—with the potential for changing political outcomes.

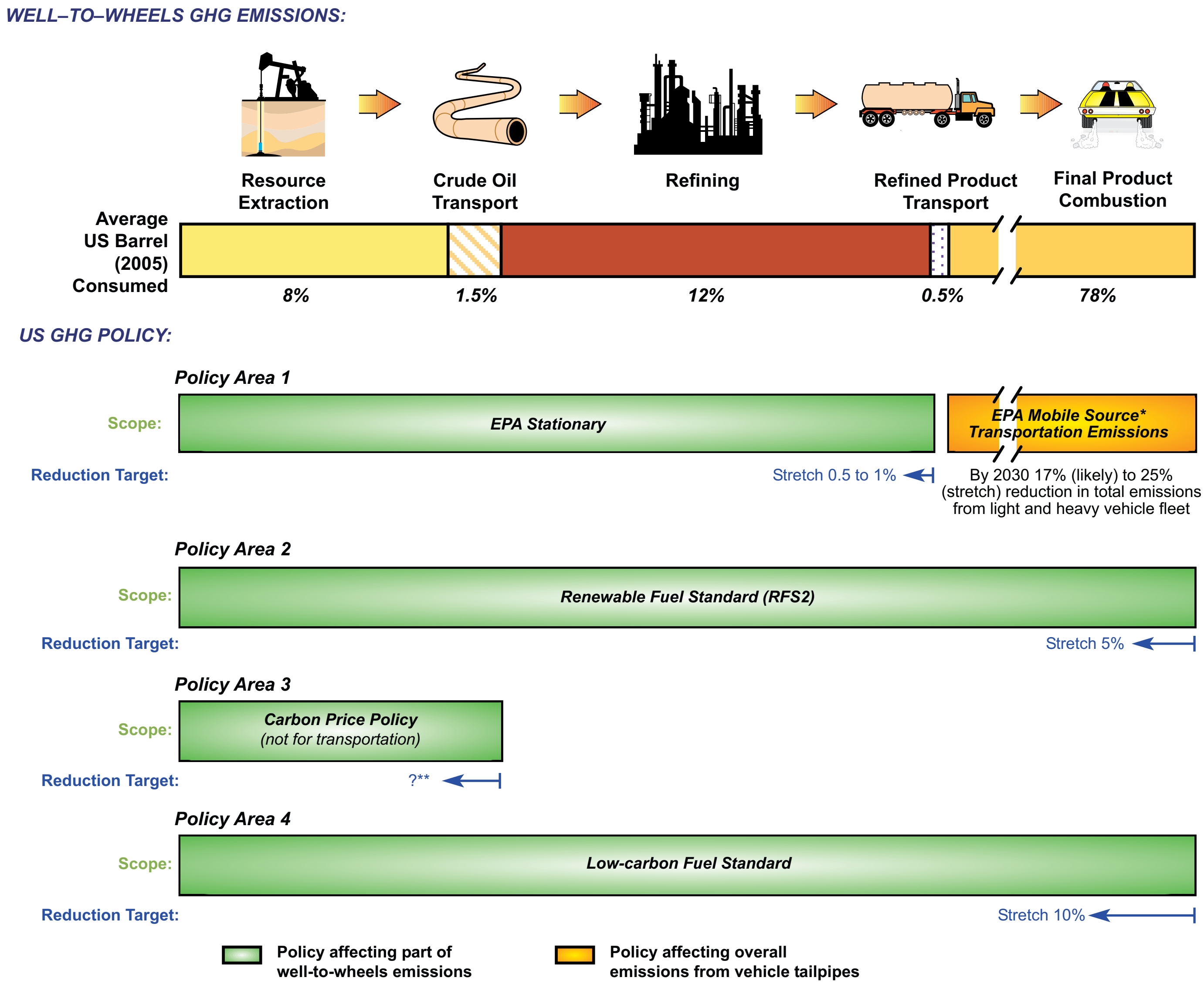
## IMPLICATIONS FOR GHG EMISSIONS REDUCTIONS

Though some of the policies analyzed in this paper target unique GHG reductions, many of the policies overlap in scope, leading to some duplication of efforts (see Figure 5).

Policies that specifically target fuel consumption are the most effective at reducing US transportation GHG emissions. Therefore the EPA Mobile Source Transportation Emission rules have the most potential to reduce US GHG emissions by 2030; reductions of between 332 mt $CO_2$e per year (assuming 35 mpg for light duty in 2016 plus plans for heavy duty) and 448 mt $CO_2$e per year (stretch case of 60 mpg for light duty in 2025 plus plans for heavy duty). Put another way, by 2030 this policy could reduce all US GHG emissions by 5 to 10 percent (compared with a case with no vehicle fuel economy improvements). These regulations are effective because they target emissions from the vehicle—which are responsible for 70 to 80 percent of the emissions related to producing and consuming transportation fuels.

**Figure 5**

**US GHG Policy: GHG Reduction Targets and Scope**




Source: IHS CERA.
*By improving vehicle efficiency, the total emissions from transport will be reduced, effectively lowering the combustion emissions per mile driven. However, no mitigation strategy for petroleum-fueled vehicles can reduce emissions per unit of energy, which is the basis of the well-to-wheels combustion emissions (78 percent of the emissions for average crude consumed in the United States).
**Depending on the price associated with emitting carbon, the total amount of reductions will vary.
10207-7

The other policies examined in this paper (EPA stationary mandates, RFS2, carbon tax, and LCFS) result in significantly more modest reductions in GHG emissions (see Table 1).

**Table 1**

**GHG Reduction Policy Comparisons**

(GHG reductions in million metric tons of $CO_2$e per year)

| Policy | High Case | Likely Case | Probability Policy Will Be Implemented Widely | Status |
|---|---|---|---|---|
| EPA stationary | 19 (4–5 average-size coal plants) | Much less | Medium—(regulated now but with a chance the EPA will be slowed) | BACT is regulated; NSPS is under development |
| EPA mobile | 448 (116 average-size coal plants) | 2016 mandate more than 332 (86 average-size coal plants) | Likely Case—High<br>High Case—Medium | Current “likely case” is regulation at federal level. “High case” could be reduced by legislators |
| RPS2 | 138 (32 average-size coal plants) | 20 (5 average-size coal plants) | High—In law today, but not likely to meet current targets by 2022 | Now regulated at federal level |
| Carbon price | Negligible | Negligible | Low | Only in California for transportation starting in 2015. |
| LCFS California | 15 (4 average-size coal plants). About 13.8 of this may have resulted from EPA policy regardless of LCFS | Less | Medium—In law today but not likely to meet current targets by 2020 | In law today for California; other states looking to adopt similar policy. |

Source: IHS CERA.

## SLOW MOTION OIL DEMAND DECLINE

In IHS CERA's expected policy case (a scenario in which RFS2 and LCFS policies do not fully meet current mandates, and EPA introduces less-stringent fuel efficiency standards for 2025), by 2030 US petroleum-based demand is just slightly below current levels, near 18 mbd compared with 20 mbd without these policies. The relatively modest decline in petroleum-based oil demand (not including biofuels) illustrates the "slow motion" effect of GHG policies. The slow response is imposed by two factors: the long time horizon required to replace the existing vehicle fleet and the ongoing demand growth for transportation.[1] In our stretch case all policies overcome implementation challenges, achieve their mandates, and provide larger reductions in emissions and US oil demand; and demand for petroleum-based oil (not including biofuels) could drop below 16 mbd by 2030.

## OIL SANDS IMPLICATIONS

Though US petroleum-based oil demand is on a slow-motion downward trend, Canadian oil supply is on the opposite trajectory and pace—likely doubling in the next decade. Could oil sands supply outgrow its only notable market? Not likely; even in our stretch case—with significant lower US crude demand and very high oil sands growth—the United States could absorb all oil sands supply and at the same time significantly reduce the need for other foreign imports.[2] Even beyond 2030 the United States will remain one of the world's largest oil markets and a natural and viable export market for the Canadian oil sands.

Yet, given the higher carbon intensity of oil sands crudes compared with the "average" crude used in the United States, some of the policies analyzed in this report, if adopted more widely either on a nationwide scale or by states, could disproportionately raise the cost of oil sands and decrease its competitiveness compared to other supply options. One of these policies is a California-style LCFS that would require fuel suppliers to use a greater amount of potentially costly low-carbon alternative fuels (such as biofuels, electricity, or natural gas) to offset the carbon intensity of oil sands crudes. Another is carbon price policy, specifically rules that do not account for carbon costs already incurred in Canada, resulting in charging the same carbon molecule multiple times, creating potentially higher costs for Canadian producers, and lowering returns on oil sands investments.

The uncertainty about the final effects of US GHG policy on oil and on oil sands is already adding risk to billions of dollars in oil sands investments. If US policy were to considerably weaken oil sands economics or market access, this would create a corresponding incentive for oil sands to reach new, more profitable, destinations—with consequences for US energy security. As a result, even if oil sands are able eventually to navigate these policies (especially the ones that affect them more than other sources of oil supply), the policies still have potential implications that will shape the future role of the oil sands in the fabric of North American energy security, economic growth, and environmental outcomes.

1. Today's vehicle fleet is an impediment to reducing oil demand. A typical car is on the road for 12 to 15 years before it is replaced, and other vehicles have even longer lives.
2. Assuming by 2030 US domestic supply of between 5 and 6 mbd and a high stretch case for oil sands production of 5.7 mbd, compared with 1.35 mbd in 2009.

## REPORT PARTICIPANTS AND REVIEWERS

On November 18, 2010, IHS CERA hosted a focus group meeting in Washington, DC bringing together oil sands stakeholders to discuss perspectives on the key issues related to US GHG policy and oil sands. 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
Brookings Institution
Canadian Association of Petroleum Producers (CAPP)
Canadian Oil Sands Limited
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Devon Energy Corporation
Energy and Environmental Solutions, Alberta Innovates
Energy Resources Conversation Board (Alberta) (ERCB)
General Electric Company (GE)
Imperial Oil Ltd.
In Situ Oil Sands Alliance (IOSA)
Marathon Oil Corporation
National Round Table on the Environment and the Economy (NRTEE)
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Statoil Canada Ltd.
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## IHS CERA TEAM

**James Burkhard,** Managing Director of IHS CERA's Global Oil Group, leads the team of IHS CERA experts that analyze and assess upstream and downstream market conditions and changes in the oil and gas industry's competitive environment. A foundation of this work is detailed short- and long-term outlooks for global crude oil and refined products markets that are integrated with outlooks for other energy sources, economic growth, geopolitics, and security. Mr. Burkhard's expertise covers geopolitics, industry dynamics, and global oil demand and supply trends.

Mr. Burkhard also leads the IHS CERA Global Energy Scenarios effort, which combines energy, economic, and security expertise across the IHS Insight businesses into a comprehensive, scenarios-based framework for assessing and projecting global and regional energy market and industry dynamics. Previously he led the IHS CERA study *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030,* which encompassed the oil, gas, and electricity sectors. He was also the director of the IHS CERA Multiclient Study *Potential versus Reality: West African Oil and Gas to 2020.* He is the coauthor of IHS CERA's respected *World Oil Watch,* which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Before joining IHS CERA Mr. Burkhard was a member of the United States Peace Corps in Niger, West Africa. He directed infrastructure projects to improve water availability and credit facilities. He was also a field operator for Rod Electric. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

**Jackie Forrest,** IHS CERA Director, Global Oil, leads the research effort for the IHS CERA Oil Sands Energy Dialogue. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products. She actively monitors emerging strategic trends related to oil sands including capital projects, economics, policy, environment, and markets. She is the author of several IHS CERA Private Reports, including an investigation of US heavy crude supply and prices and West Texas Intermediate's price disconnect from the global oil market. 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. 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. 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. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

**Rob Barnett,** IHS CERA Associate Director, specializes in energy sector economics, environmental policy and strategy, and emissions markets. Mr. Barnett is responsible for the climate change and clean energy assumptions that underpin IHS CERA's Global Scenarios, including carbon dioxide emissions price outlooks. He is the author of numerous IHS CERA reports on topics that include global emissions trends, US clean air regulations, Chinese greenhouse gas (GHG) emissions trends and policy, life-cycle GHG emissions accounting, cost recovery for pollution control expenditures, and European emissions trading. He led the environmental market analysis for the IHS CERA Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance*. He also contributed to the IHS CERA Multiclient Studies *Crossing the Divide: The Future of Clean Energy; Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030;* and *Clearing the Air: Scenarios for the Future of US Emissions Markets*. Prior to joining IHS CERA Mr. Barnett worked for Clemson's Power Quality and Industrial Applications Laboratory, where he modeled electric power systems to assess the impact of distributed generation. Mr. Barnett holds BS and MS degrees from Clemson University and an MA from Boston University.

**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.

# The Role of Canadian Oil Sands in US Oil Supply

SPECIAL REPORT

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## About This Report

**Purpose.** This IHS CERA report is intended to offer an independent assessment of the potential role of Canadian oil sands in future US oil supply. Volatile oil prices, supply uncertainty, and concerns about global warming have intensified the worldwide debate about oil resource development. In North America this has pushed the debate on development of the Canadian oil sands to center stage. The outcome of this debate will determine the economic and political playing field for the oil sands industry and will have a broader impact on oil supply and energy security in the United States and beyond.

**Context.** This is the first in a series of reports from the IHS CERA *Canadian Oil Sands Dialogue.* The Dialogue convenes stakeholders in the oil sands to participate in an objective, transparent 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. The 2010 Dialogue program and associated reports cover four oil sands topics:

- the role of Canadian oil sands in US oil supply
- life-cycle greenhouse gas emissions
- oil sands technology: advances and outlook
- impact of greenhouse gas policies

The Dialogue builds on the foundation of IHS CERA's 2009 Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance.* The main report of the past study can be downloaded at www2.cera.com\oilsands.

**Methodology.** This report includes multistakeholder input both from a focus group meeting held in Calgary on Febuary 4, 2010 and from feedback on a draft version of the report. IHS CERA also conducted its own extensive research and analysis 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 this report for a list of participants and the IHS CERA team).

**Structure.** This report has four major sections, including the Key Implications:

- Key Implications
- Part I: Understanding US Oil Demand. How much energy will the United States require in the future, and how much of this demand will need to be met by oil?
- Part II: Assessing Potential US Oil Supply. Considering global oil demand, where could future US oil supply be sourced? What type of supply is likely to be available?
- Part III: A Role for Oil Sands in US Oil Supply. How competitive are the Canadian oil sands with other potential sources of new supply? What are other aspects of increased oil supply from Canada?

We welcome your feedback regarding this IHS CERA report. Please feel free to e-mail us at info@ihscera.com and reference the title of this report in your message.

For clients with access to **IHSCERA.com,** the following features related to this report may be available online: downloadable data (excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

# THE ROLE OF CANADIAN OIL SANDS IN US OIL SUPPLY

## KEY IMPLICATIONS

What is the role of Canadian oil sands in US oil supply today and in the future? Oil sands are already an important source of US oil supply, but the growth potential is much larger, as much as three to four times higher in 2030 than in 2009.

- **Oil will continue to play a critical role in future US energy supply.** In the United States oil accounts for over 40 percent of energy consumption. Despite an outlook for relatively flat US oil demand growth to 2030, the United States will maintain its position as the world's largest oil market over the next two decades. Oil will continue to be the largest source of transportation fuel during this time. Considering current technologies and costs, even with subsidies, oil alternatives such as biofuels, electric vehicles, and natural gas vehicles are more expensive than oil.

- **Over the next 20 years, both globally and within the United States, new sources of oil supply will be required.** Globally, to satisfy growing oil demand and offset declines from existing resources, new sources of oil supply are required. Over the past decade 70 percent of US imports have come from five countries—Mexico, Canada, Venezuela, Saudi Arabia, and Nigeria. In the next two decades it is likely that some of the top US suppliers will change. Some suppliers will be unable to maintain current levels of exports owing to declining production, growth in domestic demand, or expansion into new export markets. As rapid oil demand growth from the developing world keeps steady pressure on supplies, traditional US suppliers are likely to shift increasing shares of new production to these markets.

- **Oil sands offer the possibility of increasing North American oil supply security, with the potential to become the largest source of US oil imports.** Does the United States consider Canadian oil as foreign oil? "Foreign" implies geographically distant or unknown. By most measures Canada's oil is less foreign than other potential sources of supply. Oil supply from Canada is stable, proximate, connected by pipelines, and part of a limited set of oil development opportunities in which private oil companies—including US firms—can openly and securely invest. By 2030 in a high growth scenario oil sands could contribute 36 percent of total US oil imports. In a moderate growth case oil sands could grow to 20 percent of US oil imports, up from 8 percent today. Under both the low and high projections the Canadian oil sands play a key role in supplying the North American market.

- **Energy security does not need to be at odds with the environment.** Innovation in oil sands has been a constant theme. Since its inception, the industry has made and continues to make major technological strides in optimizing resources, innovating new processes, reducing costs, increasing efficiency, reducing greenhouse gas (GHG) emissions, and reducing its environmental impact. However, new techniques and technologies are needed to continue to grow production sustainably. Cooperation between governments, both in the United States and Canada, and the private sector is crucial to continued advancement of new technologies.

- **Oil sands are competitive with numerous other sources of oil supply.** Oil sands face the challenge of higher costs, but they are not alone in this regard. Comparing the economics of some of the world's largest sources of new oil supply, numerous projects are in the same economic range as oil sands.

—April 2010

# THE ROLE OF CANADIAN OIL SANDS IN US OIL SUPPLY

> "Geography has made us neighbors. History has made us friends. Economy has made us partners. Necessity has made us allies."
> —John F. Kennedy, Address Before the Canadian Parliament in Ottawa, May 17, 1961.

What is the role of Canadian oil sands in US oil supply today and in the future? The answer to the first part of the question is clear: growth in oil sands production has been the main driver in making Canada the largest supplier, by far, of foreign oil to the United States. Oil sands production grew from 0.6 million barrels per day (mbd) to 1.35 mbd from 2000 to 2009, more than a twofold increase. This more than offset declines in conventional Canadian production and boosted US imports of Canadian crude oil from 1.4 mbd to 1.9 mbd in that time frame.* The more challenging question is about the future. Even if nothing changes, the oil sands, by virtue of their size today, will be an important source of supply for many years to come. But the growth potential is much bigger—volumes could be as much as three to four times higher in 2030 than in 2009. But how much of that potential will be realized is subject to a range of economic, political, and environmental variables.

The objective of this report is to provide an independent perspective on the future role of Canadian oil sands in US oil supply by identifying a credible range of outcomes—high and low—and the assumptions attached to each. The importance of the oil sands goes well beyond the borders of Alberta and the midwestern United States, the principal market for oil sands today. The oil sands are a vital element of the economic and political fabric that makes Canadian-US trade relations among the most important and mutually beneficial relationships in the world. The United States and Canada are each the other's largest trading partner, and energy is a significant part of this trade. The oil sands also make Canada one of the few countries in the Western Hemisphere that has the potential to significantly boost oil production in the next two decades. The potential gains of increasing output are evident, but environmental and social concerns need to be addressed in order to optimize the benefits to a broad range of stakeholders, including governments, oil sands operators, investors, local communities, nongovernmental organizations, and the general public.

The first two parts of this report focus on understanding US oil demand and assessing potential future sources of US oil supply. These provide the context for the final part of the report, in which we evaluate the future role for Canadian oil sands in US crude supply.

*Imports of refined products from Canada are not included in this figure.

## Oil Sands 101

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, second only to Saudi Arabia. Canada's oil sands are concentrated in three major deposits. The largest is the Athabasca, a large region around Fort McMurray in northeastern Alberta. The other two areas are Peace River in northwest Alberta and Cold Lake, east of Edmonton.

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands comes from bitumen, an extra-heavy oil with high viscosity. Because of 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. Oil sands are unique in that they are produced via both surface mining and in-situ thermal processes.

- **Mining.** About 20 percent 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 (primarily soils and vegetation) 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.
- **In-situ thermal processes.** About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling methods, In-situ thermal methods inject steam into the wellbore to lower the viscosity of the bitumen and allow it to flow to the surface. Two thermal processes are in use today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).

Raw bitumen is solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with light oil liquid 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 light crude oil.

- **Upgraded bitumen, or synthetic crude oil (SCO),** is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions. Although SCO can be sour, typically, SCO is a light, sweet, bottomless crude oil, with API gravity typically greater than 33 degrees.
- **Diluted bitumen (dilbit)** is bitumen mixed with a diluent, typically a natural gas liquid such as condensate. This is done to make the mixed product "lighter," lowering the viscosity enough for the dilbit to be transported in a pipeline. Some refineries will need modifications to process large amounts of dilbit feedstock, because it produces more heavy oil products than most crude oils. Dilbit is also of lower quality than most crude oils, containing higher levels of sulfur and aromatics. Some dilbits contain high amounts of corrosive acid, as measured by the total acid number. The high acid content is thought to cause corrosion to refinery equipment. However, new research is concluding that bitumen, although high in total acids, may not be as corrosive as other crudes with similar total acid levels.*
- **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.
- **Dilsynbit** is a combination of bitumen and heavy conventional crudes blended with condensate and SCO, resulting in a product that more closely resembles conventional crude oil.

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*Final Report CAPP-AERI TAN Project, prepared by Crude Quality Inc., released May 29, 2009.

# PART I: UNDERSTANDING US OIL DEMAND

Oil is certain to play a critical role in future energy supply globally and in the United States. Today oil accounts for about 35 percent of global energy supply—the largest share of any form of energy. IHS CERA estimates that global oil demand, excluding biofuels, will grow from 84.2 mbd in 2009 to between 92 and 105 mbd by 2030. We developed these estimates by examining future demand through the lens of two scenarios that establish high- and low-end boundary conditions for demand.

## A TWO-SPEED WORLD FOR OIL DEMAND GROWTH

In 2009 the United States consumed about 20 percent of world energy supply and 22 percent of world oil supply (excluding biofuels), representing about 24 percent of world gross domestic product (GDP). The United States will remain the largest oil market and one of the largest overall energy consumers for many years to come. However, demand in the rest of the world, especially in Asia, is increasing at a faster rate. For example during 2000–09 total oil demand in China nearly doubled, while US oil demand declined 10 percent. Nearly all of the growth in world oil demand is expected to take place outside of OECD countries—in emerging markets in Asia, the Middle East, Latin America, and Africa. This rapid oil demand growth in the developing world is likely to result in a reshuffling of world oil flows, with many of the traditional oil suppliers to the United States shifting some of their supply to the growth markets. In general IHS CERA believes that the OECD as a whole has passed "peak demand."

Transportation remains the one sector where oil retains a near-monopoly, in contrast to many other energy-intensive industries that are no longer fueled by oil. Thus oil demand growth depends primarily upon the transportation sector. Growth in demand for personal mobility is expected to be the primary driver of developing-world oil demand, as robust economic growth translates into both higher living standards and increased demands for transportation.

In the United States, on the other hand, the personal transportation market is mature. There are more vehicles than registered drivers, and population growth is expected to be modest. In the past two decades gasoline demand grew mostly in line with population growth, since the efficiency of the light-duty vehicle fleet was stagnant. Looking to the future, however, this picture is changing. Regulation will increase the efficiency of new cars and light trucks through the middle of this decade, and government policy will encourage increased sales of alternative vehicles, gradually improving the efficiency of the overall fleet. This efficiency increase is likely to cancel out growth in fuel demand resulting from population growth. However, the factors listed above will affect US oil demand slowly. A typical car is on the road for 12 to 15 years before it is replaced. Therefore, even a significant improvement in fuel economy standards or an improvement in the economics and sales of alternative vehicles takes years to have a significant impact on oil demand (see the box "How Competitive Are Today's Fuel and Vehicle Alternatives to Oil?").

**How Competitive Are Today's Fuel and Vehicle Alternatives to Oil?**

How competitive are today's transportation alternatives with gasoline and diesel? Cost is a key issue only if and when alternatives become "transformative technologies"—offering either more utility for the same price or the same utility for a lower price—will they start to win significant and enduring market share from gasoline and diesel for transportation.

Comparing today's economics and considering the effect of government incentives, transportation alternatives are still more expensive than oil (see Figure 1). Concerns about high energy prices, energy security, and global warming have resulted in more research and development of these technologies. In time new innovations could help these technologies to close the "cost gap" and win increased levels of market share. But even with increased acceptance, the affect of these technologies on gasoline demand will occur slowly owing to the long time horizon associated with replacing the existing vehicle fleet and the continued competitiveness of the internal combustion engine.

## US OIL DEMAND: UNLIKELY TO SURPASS 2005 PEAK

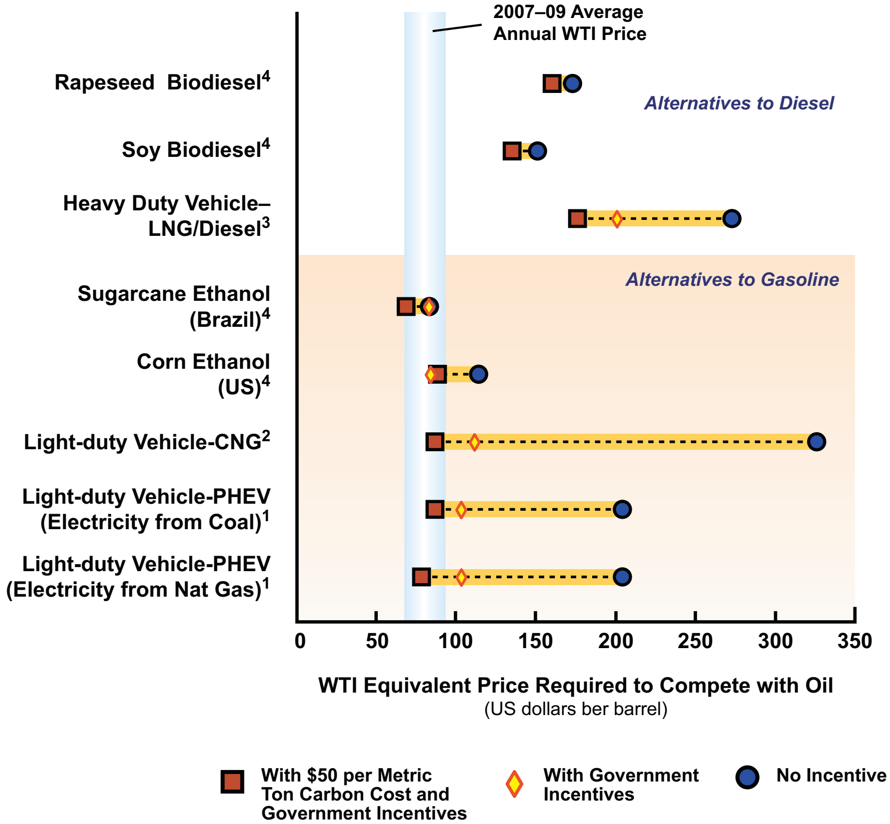
Trends such as an aging population and increasing fuel economy standards put gradual downward pressure on US oil demand. As a result, overall oil demand in the United States has likely already peaked. US oil demand reached its high water mark in 2005 at 20.9 mbd (excluding biofuels)—well before the impact of the economic crisis—and has been in continuous decline since then. However, the end of the oil age in this large economy is hardly imminent. The United States will continue to rely strongly on petroleum. US oil demand is projected to be between 17.8 and 19.3 mbd by 2030 (excluding biofuels). Over the next 20 years the US will maintain its position as the world's largest oil market by a hefty margin (2030 US oil demand is projected to be at least 30 percent higher than China's).

### Elements of US Oil Demand

In 2009 gasoline, excluding ethanol, accounted for 46 percent of total US petroleum demand, the largest component of transportation-related demand (see Figure 2). Even if US gasoline demand disappeared overnight, the United States would still consume nearly 10 mbd of oil with limited prospects for replacing the "nongasoline" portion of demand. Commercial-scale alternatives to diesel and jet fuel are not expected to arrive over the next two decades. Diesel will continue to be the workhorse of heavy truck freight hauling, and jet fuel will continue to power aviation. Indeed there is every reason to expect diesel demand to continue growing in any scenario featuring economic growth. Shipping may make the transition from heavy bunker fuel oil to greater volumes of diesel, but it is unlikely to move away from oil entirely.

The nontransport portion of US oil demand is also expected to change only slowly owing to a lack of alternatives. During the previous large decline in oil demand, from 1979 to 1983, total petroleum demand in OECD countries fell 7.5 mbd. But over half (4.1 mbd) of this decline in oil demand occurred as the nontransportation sectors of the economy—essentially the industrial and power sectors—permanently replaced residual fuel with coal, natural gas, and nuclear power. This massive shift was a one-time event.

### Figure 1
### Relative Economics of Transportation Alternatives to Oil




Source IHS CERA, analysis for alternative vehicles based on the levelized cost per mile traveled compared with costs of alternatives assumes 100 percent debt financing for all vehicles over 5 years, at a 7 percent interest rate with 40 percent residual value at the end of the loan period. Biofuel options based on production costs.

1. Plug-in hybrid electric light-duty vehicle (PHEV) averages 50 mpg, runs 67 percent of the time in electric mode, capital cost is $10,000 more than comparable gasoline vehicle, electricity costs $0.114 per kWh. Government incentive is $3,700.
2. Compressed natural gas (CNG) light-duty vehicle averages 28 mpg, fuel cost is 30 percent lower than gasoline, cost is $6830 more than comparable gasoline vehicle. Government incentives $4,000.
3. Heavy-duty vehicle (HDV) class 8 LNG/diesel. Extra costs for increased refueling and trip length are US$0.08 per mile. Capital cost for truck is $70,000 more than comparable diesel option, and government incentive is $32,000.
4. Average of feedstock prices from 2007 to 2009. Government incentive for corn based ethanol is $0.45 cents per gallon. Includes correction to account for lower energy content of ethanol and biodiesel.

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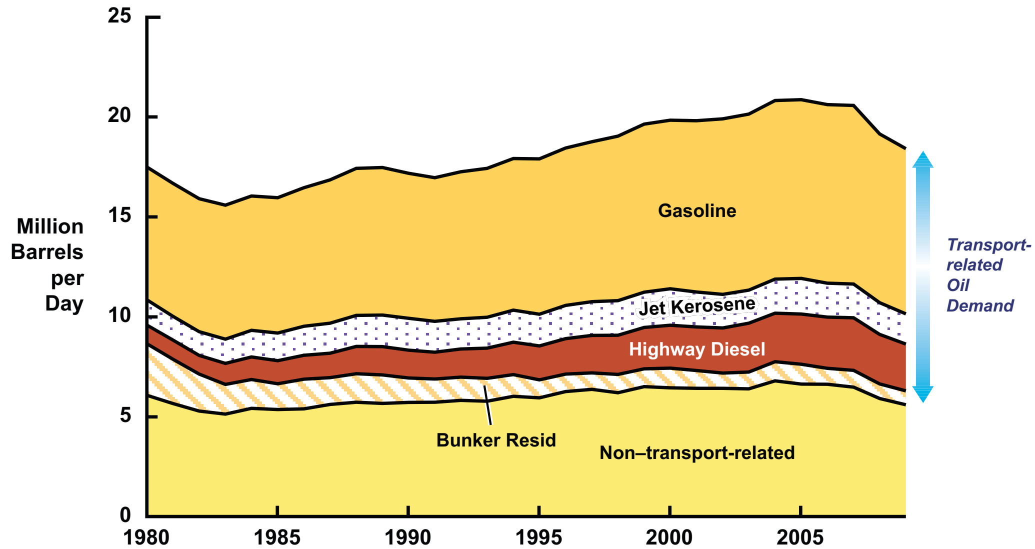
Today nontransport demand for oil primarily stems from uses such as petrochemical feedstocks, home heating, lubes, waxes, and asphalt, which have experienced only slight declines in demand over the past decade. Looking to the future, some nontransport demand will be lost as natural gas is substituted for distillate fuel in the residential, commercial, and industrial sectors and as the US petrochemical sector production declines. Other uses are expected to grow slightly, however, leaving overall demand flat.

**Figure 2**

**Breakdown of US Oil Demand**




Source: IHS CERA.
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## US Gasoline Demand: A Sharp Decline

To date US government efforts to reduce oil demand have focused primarily on reducing the largest component of demand, gasoline consumption. Government actions aimed at reducing gasoline demand include efforts to increase biofuels consumption, higher vehicle fuel efficiency standards, incentives to encourage consumers to purchase alternative vehicles, and the ongoing funding of research and development.

Within this analysis IHS CERA considers two possible cases resulting in higher or lower US gasoline demand; the range is determined by both the success of government programs and the technological advancement of alternative fuels and vehicles.

IHS CERA's low gasoline growth case considers the impact of strong penetration of biofuels, slowing of growth in how much people drive, aggressive commercialization of plug-in hybrid electric vehicles (PHEVs), some dieselization of the light-duty vehicle fleet, and the further ratcheting up of strict fuel economy standards for new vehicles.* As a result US petroleum-based gasoline demand declines by 35 percent (or 3 mbd) from 2005 to 2030 (see Table 1).

In the low gasoline growth case almost one third of the lost gasoline demand is driven by a near doubling in the fuel economy standards for new vehicles. Over 0.2 mbd of gasoline demand is avoided by increasing numbers of PHEVs, but the largest driver of reduced gasoline demand is the contribution of 1.9 mbd of ethanol by 2030—an almost threefold

*PHEVs have an all-electric range large enough to handle most day-to-day driving, with a backup conventional fuel tank to ensure a range as great or greater than that of a gasoline vehicle.

**Table 1**

**Drivers of US Gasoline Demand**

| | Current | Low Gasoline Growth Case (2030) | High Gasoline Growth Case (2030) |
|---|---|---|---|
| Ethanol production | 0.8 mbd | 1.9 mbd | 1.5 mbd |
| US ethanol consumption by feedstock | 0.8 mbd corn | 1 mbd corn<br>1 mbd sugar cane and next generation | 1 mbd corn<br>0.5 mbd sugar cane and next generation |
| New vehicle fuel economy standards (new CAFE standards) passenger miles per gallon of gasoline | Cars = 27.5<br>Light trucks = 21.4 | Cars = 50<br>Light trucks = 40 | Cars = 45<br>Light trucks = 35 |
| Change in Vehicle Miles Travelled (VMT) | 1.7 percent per year (1980–2005 average) | 1.1 percent per year (2010–30 average) | 1.3 percent per year (2010–30 average) |
| Percent of new vehicle sales from PHEVs in 2030 | 0 percent | 25 percent | 10 percent |
| Reduction in US petroleum-based gasoline demand from 2005 to 2030 | | Down 35 percent (or 3 mbd) | Down 20 percent (or 1.7 mbd) |
| US gasoline demand, excluding biofuels (mbd) | 8.3 | 5.9 | 7.2 |

Source: IHS CERA.

increase from the current level. Achieving this volume of ethanol production clearly presents a challenge. The successful development of next generation biofuel production is a crucial hurdle, but not the only one. Ethanol production levels could be constrained by both water and land limits. New biofuel production processes must reduce water consumption and use feedstocks that are both sustainable and scalable.*

Incorporating such large amounts of biofuels into transportation fuel will also be a challenge. Although a portion of the ethanol could be seamlessly blended into conventional gasoline, a significant volume—perhaps as much as 1 mbd—would need to be consumed in flex-fuel vehicles (FFVs) in the form of ethanol blends such as E85 (85 percent ethanol and 15 percent gasoline).** Both the sales of FFVs and the development of the infrastructure to distribute E85 fuel would have to accelerate, fueling stations would need to install new tanks and pumps, and consumers would have to buy growing numbers of FFVs and choose to fill up with E85. However, even the volumes of ethanol consumed in this "stretch" scenario fall

*Since ethanol refineries consume three to four liters of water for every liter of ethanol produced, water availability could become a limiting factor in some regions where ethanol refineries are sited. Depending on the feedstock used and the associated water and land limits, the final production levels could be constrained.
**In both the high and low growth scenario the maximum allowable volume of ethanol that can be blended into conventional gasoline (also known as the ethanol "blend wall") is increased from the current limit of 10 percent to 15 percent.

short of the 2.35 mbd of biofuels currently mandated by the US Renewable Fuel Standard (RFS) by 2022.*

IHS CERA's high gasoline growth case assumes that the US government adopts less challenging goals for reducing gasoline demand and that technology does not progress as quickly. US petroleum-based gasoline demand declines in this case also, by 20 percent (or 1.7 mbd) from 2005 to 2030. Ongoing penetration of ethanol; slowing growth in vehicle miles traveled per driver; increased fuel efficiency; and adoption of some alternative vehicles, including PHEVs in the later years, contribute to the demand decline.

The high-growth case assumes that about 300,000 barrels per day (bd), or 0.3 mbd of E85, will be consumed in FFVs. At this lower consumption level, implementation issues related to retail distribution of ethanol and the corresponding FFVs are less daunting.

*The RFS is a federal mandate to increase US consumption of biofuels. The RFS caps the volume of ethanol derived from corn starch at 0.98 mbd by 2015. By 2022, 1.37 mbd more is targeted to be consumed and this fuel is regulated to be derived from noncorn feedstocks. The majority of this noncorn volume—1 mbd—is regulated to be derived from cellulosic biomass (such as switchgrass, corn stover, or wood chips).

# PART II: ASSESSING POTENTIAL US OIL SUPPLY

From 2003 to 2007 growth in global oil demand surged forward each year while oil supply struggled to keep pace. The narrow balance between oil supply and demand was a key factor in the steady price rise over this period. By 2008 the cumulative impact of record-high oil prices and a severe recession led to a decline in world oil demand for the first time since 1979. In 2009 demand fell again. In total oil demand fell 1.9 mbd in 2008 and 2009, resetting oil demand back to 2005 levels and erasing four years of growth. But oil production capacity, which had struggled to keep up with demand for several years, was still expanding. By 2010 global spare oil production capacity (the difference between the amount of oil demanded and production capacity) grew to more than 6 mbd—a threefold increase over the thin spare capacity volumes tracked for much of the preceding decade.

How long will the current generous cushion of spare oil production capacity last? Much depends on the progress and pace of recovery from the Great Recession and the ability of oil companies and governments to "stay the course" and continue investing even in the face of the current oversupply.

## US CRUDE SUPPLY TODAY

Since the United States became a net importer in the late 1940s, it has relied on foreign oil to make up the gap between domestic supply and demand. In 2009 close to 40 percent of US petroleum demand was satisfied by domestic production. The remainder was imported from over 40 countries. Although foreign oil comes from many suppliers, over the past decade 70 percent of crude oil imports have been sourced from five countries (see Table 2).

Often unremarked and indeed unrecognized, Canada sits at the top of the list of foreign suppliers. Canada's share of US crude oil imports rose from 15 percent in 2000 to 21 percent in 2009, underscoring the deep and growing economic and trading relationship between the two neighbors. US total crude oil imports from Canada were 1.9 mbd, and the Canadian oil sands alone contributed half of this supply. In third quarter 2009 oil sands imports hit a new high water mark, totaling over 1 mbd.* In third quarter 2009 oil sands supply alone was the third largest source of crude oil imported to the United States (see the box "Different Yardsticks: Measuring Importers' Share of US Oil Supply"). The growing importance of oil sands in US oil supply is evident.

Over the years while imports from Canada increased, imports from other top suppliers have been in decline. From 2004 to 2008 combined imports of Mexican and Venezuelan crude dropped from 3.2 mbd to 2.5 mbd. A more conducive investment climate for oil production in both Mexico and Venezuela would be required to reverse the current trend of production decline.

*Assumes that over 120,000 bd of bitumen were supplied in dilsynbit blends, which are classified as conventional heavy crude.

**Table 2**

**Comparison of US Crude Oil Imports, 2000 and 2009**

(top suppliers)

**2000**

| | | Volume (mbd) | Share of US Imports (percent) |
|---|---|---|---|
| 1 | Saudi Arabia | 1.5 | 17 |
| 2 | Canada | 1 | 15 |
| 3 | Mexico | 1.3 | 14 |
| 4 | Venezuela | 1.2 | 13 |
| 5 | Nigeria | 0.9 | 10 |

**2009**

| | | Volume (mbd) | Share of US Imports (percent) |
|---|---|---|---|
| 1 | Canada | 1.9 | 21 |
| 2 | Mexico | 1.1 | 12 |
| 3 | Saudi Arabia | 1 | 11 |
| 4 | Venezuela | 1 | 11 |
| 5 | Nigeria | 0.8 | 9 |

Source: IHS CERA, US EIA.

**Different Yardsticks: Measuring Importers' Share of US Oil Supply**

The measure of the imports by country or supply source varies depending on the yardstick used. Three common measures are defined as follows:

- **Imports as a percentage of total US oil supply.** Compares the import volume to the total volume of US domestic and imports of crude oil, refined products, and light hydrocarbon liquids (condensates and liquefied petroleum gases). In the high-growth oil sands scenario oil sands provide 26 percent of total US oil supply by 2030.
- **Imports as a percentage of US oil imports.** Compares the import volume to the total volume of US imports of crude oil, refined products, and light hydrocarbon liquids (condensates and liquefied petroleum gas). In the high-growth oil sands scenario oil sands account for 36 percent of total US oil imports by 2030.
- **Imports as a percent of US crude oil imports.** Compares the import volume to the total volume of imported crude oil only. In the high-growth oil sands scenario oil sands constitute 47 percent of total US crude oil imports by 2030.

Not only have the sources of US supply been shifting, the types of crudes available are also changing. Since 2004 the supply of medium and heavy crudes has been tightening. This trend of decreasing volumes of heavy crudes is bumping up against an ongoing expansion of US coking capacity, further exacerbating the tight market. Declines in the supply of heavier crudes have been driven by a number of factors: declines in domestic supply, declines in Mexican and Venezuelan production, and supply declines from other smaller exporters, and more recently the growing tightness has been reinforced by OPEC's decision to reduce crude production—especially the heavy and medium grades—in response to the recession and lower oil demand.*

## SUPPLY GROWTH UNCERTAINTY

How much oil supply growth can the world expect over the next two decades? Examination of the resource base on a field-by-field basis indicates that there is ample potential for supply to meet demand to 2030 and beyond. IHS CERA estimates that oil production capacity will reach 96 to 110 mbd by 2030. To reach these supply levels, over the next two decades the oil industry would need to add between 2.8 and 3.5 mbd of new productive capacity each year or, put another way, add four to five oil-producing jurisdictions the size of Saudi Arabia over the next 20 years.**

The high-end estimate assumes that no major disruptions or investment shortfalls occur. The low-end estimate could result if oil supply difficulties, such as project delays, high costs, labor and equipment shortages, or production disruptions in important oil-producing countries, limit production growth. Sustained high prices and a significant market response toward alternative fuels and technologies would result in such an environment.

### Where Will Future US Supply Come From?

Assuming that projected growth in global supply is achieved, IHS CERA estimates that the oil supply available to the United States from both domestic production and imports will be over 20 mbd by 2030, surpassing demand.***

Over the next 20 years the list of top US crude suppliers is likely to change (see the box "Production Outlook for Top US Crude Suppliers"). Some suppliers will be unable to maintain the current levels of exports to the United States owing to declining production, growth in domestic demand, expansion into new export markets, or a combination of the above.

In the United States new oil developments in the deep water of the Gulf of Mexico, other offshore plays, Alaska, and onshore plays such as the Bakken in the northern plains are projected to add new oil supply. Over the next decade on average over 150,000 bd of new

*For the purposes of this analysis heavy crudes are defined as those with an API gravity of less than 27 degrees, medium grades have an API gravity between 27 and 36 degrees, and light crudes have an API gravity greater than 36 degrees.
**Assumes a 4.5 percent per year decline in production from existing conventional reservoirs. Supply from the production of existing heavy oil, coal-to-liquids, biofuels, and gas-to-liquids supplies are not projected to decline.
***This assumes that imports from each country that currently supplies crude to the United States change in direct proportion to the expected overall supply change for that country. Exceptions include suppliers projected to have large increases in crude supply over the next 20 years (over 1 mbd), such as Iraq, Brazil, Saudi Arabia, and Canada.

**Production Outlook for the Top US Crude Suppliers**

**Canada.** Although oil sands production has expanded rapidly in recent years, the future rate of growth is uncertain because of differing views on the environmental impact of oil sands development and project economics. IHS CERA's oil sands scenarios envision a high growth case of 5.7 mbd and a moderate growth case of 3.1 mbd by 2030. Historically the United States has been Canada's only crude market, but this situation could change in the future. Plans to build a new pipeline to Canada's west coast are progressing. If this project continues on course, by 2017 over 500,000 bd of crude could be flowing to the Asian market from Canada.

**Venezuela.** Oil production has fallen since hitting a peak of 3.2 mbd in 1997. In 2009 oil production stood near 2.5 mbd. Although Venezuela has awarded new blocks in the Orinoco Oil Belt, there are execution challenges. IHS CERA anticipates that by 2020 production could grow again, and by 2030 levels will be about equal to current production. A risk to future US imports is the possibility that larger portions of Venezuelan crude could go to other markets, such as China.

**Mexico.** Mexico could become a net importer of oil in the latter part of this decade, assuming the current rate of production decline (primarily the result of declines in the Cantarell field), a continued increase in domestic oil demand of approximately 2 percent per year, and minimal development of new supply.

**Saudi Arabia.** Saudi Arabia has completed a program of increasing oil production capacity, raising capacity to 12.5 mbd. The next project, Manifa, is not planned for production until 2014. With the start-up of Khurais at 1.2 mbd in 2009, Saudi Arabia has brought onstream one of the largest projects ever. Given the ample spare capacity due to decreased oil demand from traditional export locations and an outlook for long-term flat oil demand growth in the developed world, Saudi Arabia has been actively seeking to grow exports to new growth markets in China and India for some time.

**Nigeria.** Nigeria continues to struggle with producing at capacity owing to security challenges, which have caused a sizable portion of supply to be shut in. New offshore developments should help to offset declines, and the outlook is for relatively flat production capacity over the next 20 years.

domestic productive capacity is projected to be added each year. Despite this growth in new capacity, overall domestic supply is relatively flat as new production works to offset the declines from the existing fields. US liquids production, excluding biofuels, should average over 7 mbd over the next decade—just above where it is today.

Despite the existence of ample supply potential, rapid oil demand growth in the developing world will keep steady pressure on supplies. Traditional US suppliers are likely to shift increasing shares of new production to these growth markets. If production growth is robust, this should not affect the United States. However, if the oil markets experience shortages anywhere in the world, either through a loss of supply or delays in supply growth, the effects will quickly reverberate to all crude importers.

Even among the largest US suppliers, there are numerous downside risks to IHS CERA's supply outlooks. What if supply growth from the oil sands is less than projected? What if some of Canadian supplies are diverted to Asia? What if new volumes of heavy crude from

Latin America do not materialize or countries divert increasing volumes of exports to Asia? What if technical challenges in ultradeep water projects slow production growth? If these downside risks unfold, IHS CERA estimates that the United States would drop between 3.5 to 4 mbd of the projected crude supply by 2030. Admittedly not all of these circumstances are likely to unfold, but they are all possible.

*Spotlight on the "O-15"*

IHS CERA compiled the "O-15"—the top 15 countries in terms of the potential to increase oil production over the next decade (see Figure 3). The rankings shift over time; currently Canada ranks eighth. Examining Canada's characteristics within the context of the O-15 provides insight into Canada's role as a long-term future supplier of crude oil to the United States.

- **Of the O-15, Canada has among the most, if not the most, open oil and gas investment climate.** No company enjoys a privileged position because of state ownership.

- **Canadian oil sands capacity is not government controlled.** The balance between governments and companies in the global oil industry has shifted toward governments. In

**Figure 3**

**The O-15: The 15 Countries with the Most Potential to Increase Oil Production to 2020**


Source: IHS CERA.
90107-32

the next decade nearly 70 percent of planned new productive capacity will be owned by government interests (through either a government joint venture partnership or ownership of a project by a national oil company). Of the 30 percent of non–government-controlled new capacity, one tenth of this supply comes from the Canadian oil sands.

- **Canada is a neighbor in many ways.** Among the O-15 Canada is the closest in proximity and policy to the United States.
- **At the project level, government regulation of Canadian oil developments is among the most robust in the world.** Relative to traditional suppliers (Venezuela, Mexico, and Canada) most new productive capacity is distant from the United States. Canada and Brazil are the only countries in the Western Hemisphere included in the O-15.
- **Canada has the capacity to grow heavy crude supplies.** Canada, Iraq, Kuwait, and Saudi Arabia are the only countries in the O-15 projected to add new heavy crude oil supplies. Heavy crudes are an important part of the feedstock mix for US refineries.

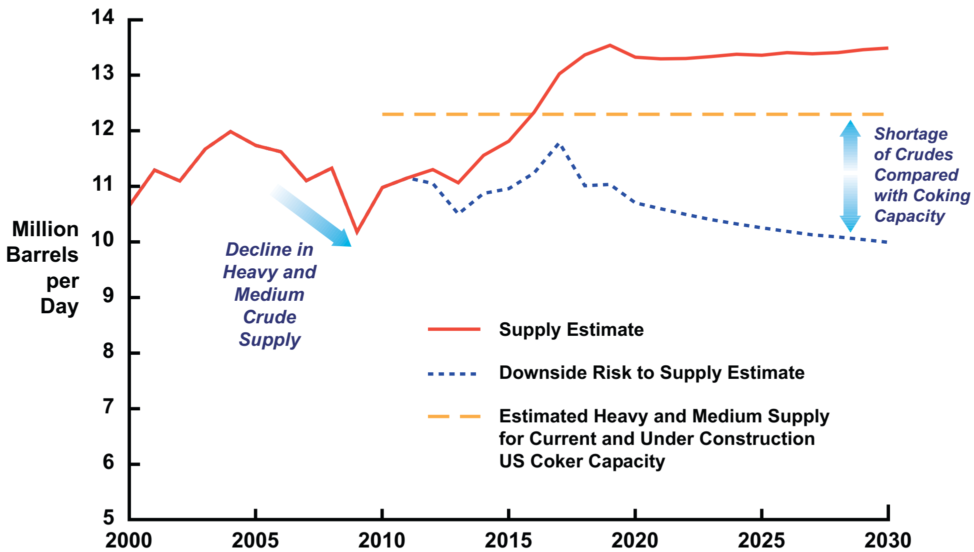
## Will Available Crude Oil Match Refiners' Needs?

In IHS CERA's downside risk analysis, in which the United States would need to find between 3.5 and 4 mbd of additional crude supply, nearly half of the global supplies at risk are heavy crudes; the remainder are medium crudes. The loss of these supply sources would further exacerbate today's tight market for heavy and medium crudes in the United States. The US refining infrastructure is complex, making it well suited for heavier crude slates; and the complexity is still growing. Based on known projects already under construction or likely to proceed, US coking capacity is expected to increase by over 300,000 bd from 2009 to 2013. To capitalize on these costly upgrading investments and maximize refined product production, US refiners will need heavy and medium crudes (see Figure 4 and the box "Implications of a Shortfall of Heavy Crude Oil Supply for US Refining Industry").

Even with the base case supply outlook—not considering the downside risk analysis—the trend of declining supplies of medium and heavy crudes and increasing coking capacity is expected to keep the market for heavier crudes tight until 2015 or 2016. At that point stabilized Venezuelan production and substantial growth in Canadian oil sands supply converge with growth in medium and heavy supply from the United States, Brazil, Saudi Arabia, and Iraq to unravel the tightness in the market and the competition for these crudes.

**Figure 4**

**Supply of Heavy and Medium Crude Oil to the US Market**




Source: IHS CERA.
Note: The downside case considers the effect of possible delays in supply growth from traditional US suppliers. Downside risks includes effects from slow growth in Canadian oil sands, delays in ultradeepwater developments, diversion of some supply to new growth markets, and possible declines in supplies from Latin America.
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## Implications of a Shortfall of Heavy Crude Oil Supply for US Refining Industry

What are the implications of a shortfall of heavy and medium crude supply for the US refining industry? Half the refineries in the United States have cokers, compared with one in six in Europe. Cokers are sophisticated reactors that upgrade the heaviest crude fractions into valuable light products. Because cokers are most efficient at processing heavy crudes, a shortage of heavier crudes will affect the mix of transportation fuels produced by US refiners.

Heavy crudes naturally yield a high proportion (50 percent or more) of heavy fractions that are upgraded essentially broken down or refined into products by refinery reactors (cokers and crackers). These reactors produce diesel and gasoline from the heavy crude fractions.

Light crudes naturally yield a high proportion (60 percent or more) of light crude fractions. After upgrading product quality, these fractions are used directly for transportation fuels.

A coking refinery configured for heavy crudes faces two problems when processing lighter crudes:

- Light crudes yield more light products, which overfills the units that upgrade transportation fuel quality (motor octane, sulfur removal, etc.).
- Light crudes yield less heavy products, and the refinery reactors used for upgrading are underutilized.

The result is a reduction in the volumes of gasoline and diesel produced. In the near term if a refiner configured to process heavy crude is forced to process 100 percent lighter crudes, the volume of gasoline and diesel produced can decrease by 15–20 percent, and refinery profitability also declines. In reality if forced to run light crudes over the longer term, the refiner would be forced to make refinery modifications to accommodate the new feedstock.

Bitumen from the Canadian oil sands is heavier than most other crudes supplied to the United States. Bitumen could offer feedstock flexibility to US refiners. When bitumen is blended with conventional crudes, the resulting mix “fits” well into a refinery configured for conventional heavy crudes. The volumes of produced transportation fuels are maintained and, in many cases, increase—often diesel volumes are boosted. However, to process increased volumes of bitumen, some refineries would require modifications.

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*Bitumen has unique properties, such as high amounts of sulfur and high yields of middle distillates, that may require some modifications to the refinery.

# PART III: A ROLE FOR OIL SANDS IN US OIL SUPPLY

Enhancing US supply security is critical so that oil and other forms of energy are catalysts, not hindrances, to economic growth. History illustrates the affects of oil shocks. From 1950 to 1990 there were six major disruptions in oil supply resulting in oil price increases that reduced the growth of the US economy. In each shock panic and expectations of conflict also drove price increases.

More recently the "new oil shock" sent oil prices from $30 in 2003 to $147.27 in 2008. This oil shock was brought on not by a single event, but by a convergence of factors: the narrow balance between oil supply and demand, political tensions in several major exporting countries, increasing development costs for new oil supply, and the growing influence of investors and financial markets on the price of oil. High prices forced oil demand to the breaking point—and demand finally weakened. In the United States and around the globe the financial crisis compounded the oil shock's effects, resulting in the worst economic downturn in more than 50 years.

The oil sands offer the United States the possibility of greater oil supply security. The ultimate pace of oil sands growth and the amount available to the US market will hinge on finding the appropriate balance between protecting the environment and realizing the full economic and energy security potential of the oil sands resource.

## ECONOMICS OF OIL SANDS COMPARED WITH OTHER SOURCES OF OIL

The oil sands, like many other complex oil projects around the world, face the challenge of high development costs. Although oil sands costs are roughly comparable to those of some other large potential sources of new supply, they are higher than many projects in the Middle East and other low-cost producing regions. Even considering a strong move to oil alternatives, meeting global oil demand over the next 20 years will require that the full portfolio of oil development projects, including expensive sources of supply, are brought online around the world.

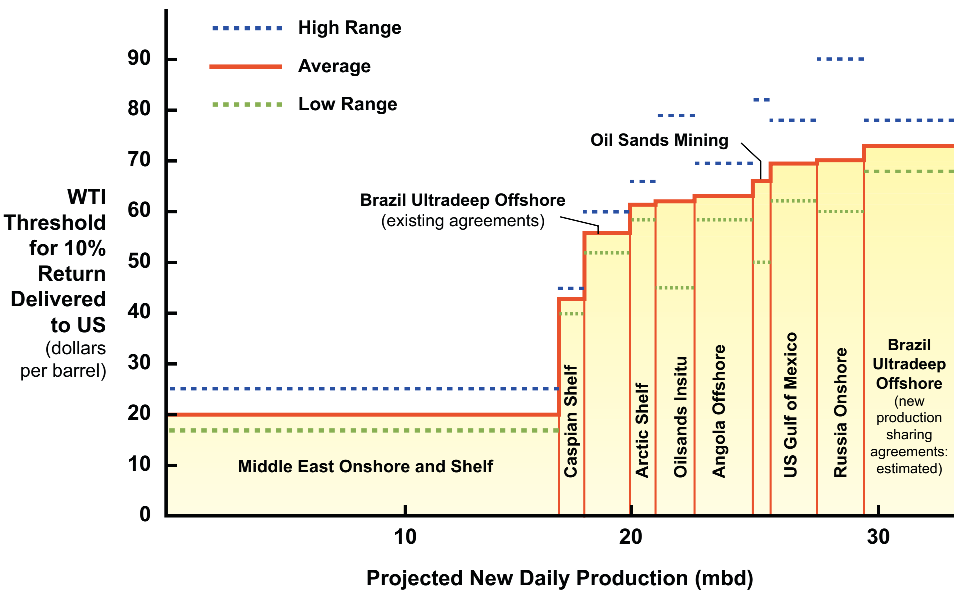
The list of potential oil development projects is long. How do some of the largest projects—ones with the greatest ability to add new productive capacity over the next five to ten years—compare with the economics of oil sands?

Figure 5 compares the economics of a number of oil development projects, evaluating the threshold West Texas Intermediate (WTI) equivalent price required to obtain a 10 percent return on the capital investment. The new oil developments compared are substantial, representing over 34 mbd of new productive capacity—as much as half of the total new capacity required to meet the 2030 high oil demand projection.

The economic analysis of each development project considers each country's royalties, taxes, government take, sustaining capital, variance in heavy and medium crude prices, transportation costs to deliver the crude to the US market, reserve sizes, current range of capital costs (assuming no future cost escalation from third quarter 2009), and operating

**Figure 5**

**Range of WTI Threshold Costs for New Crude Supply**




Source: IHS CERA.
Note: Comparison of current economics of major new supply planned over the next 5 to 10 years. Compares the threshold WTI-equivalent price of each development by calculating the oil price required to obtain a 10 percent return on the capital investment over the life of the project, including the transportation costs to deliver the crude to the US market. For oil sands projects, the economic range considers the range of economics for both integrated investments (producing upgraded synthetic crude oil or refined products) and upstream-only investments (producing dilbit). Costs are on the low range for jurisdictions that use production-sharing or profit-sharing types of agreements, which are applicable only when the projects profit (not at breakeven point). Russian onshore projects assume current upstream and export tax regimes are in effect. Threshold prices for Brazil ultradeep offshore new production-sharing agreements and productive capacity are both estimated as there have not been any contracts awarded under these new terms.
00204-21

costs. For oil sands projects the economic range is quite large—it considers the range of economics for both integrated investments (producing upgraded synthetic crude oil or refined products) and upstream-only investments (producing dilbit). A cost for carbon emissions is not included for any of the projects compared.

Oil sands face the challenge of higher costs, but they are not alone. A comparison of the costs of some of the world's largest sources of new oil supply reveals that numerous projects are in the same economic range as oil sands.

## A ROLE FOR OIL SANDS IN NORTH AMERICAN ENERGY SUPPLY

The magnitude of the oil sands resource, the second largest recoverable oil reserve in the world at 170 billion barrels (with the potential to grow many times larger as technical advancements unlock more of the resource), makes the oil sands significant in the context of global energy security. The sheer size of the resource, combined with one of the world's most open oil and gas investment climates, puts the oil sands in a shrinking group of oil development opportunities in which private sector oil companies, including US firms, can openly and securely invest.

But how will oil sands evolve in the context of US oil supply? The pace of the development could take many trajectories. IHS CERA envisions oil sands production ranging between 3.1 and 5.7 mbd by 2030. Although oil sands production alone will not meet all the world's energy needs (the range would equate to about 3 to 5 percent of global petroleum supply), it has the potential to increase US energy security dramatically while providing an engine of economic growth for the US and Canadian economies. Oil sands production of 5.7 mbd would supply 36 percent of US oil imports by 2030, compared with 20 percent in a moderate oil sands growth case and 8 percent today.

The Obama Administration's energy policy has the stated goal of decreasing dependence on foreign oil. In fact since the first oil shocks the desire for energy independence has been a constant theme in US energy policy. But does the United States consider Canadian oil foreign? Foreign implies far-off or unknown. By most measures, Canada is less foreign than other sources of supply—Canada and the United States have a highly efficient and integrated energy trade, moving electricity, natural gas, and oil efficiently, every day, via an interdependent network of transmission grids and pipelines.

Canada is a strong ally of the United States with over $1.5 billion of goods traded each day over the border. Canada is also a trusted partner on security matters.*

The United States will continue to rely on imported oil into the foreseeable future. Sourcing increasing volumes of oil from Canada offers the possibly of increasing North American oil supply security.

## CONTRIBUTION OF OIL SANDS TO THE NORTH AMERICAN ECONOMY

The growth of oil sands production in the past decade—up 225 percent—is a testament to Canada's open investment climate. US companies in particular play an important role. Collectively oil sands production from US-headquartered firms was 0.4 mbd in 2009, or about 30 percent of the total production. Financial markets are also connected. To date US investors have played a vital role in supplying the capital required for oil sands investments.

Oil sands investments have not only provided returns to investors, but have also created jobs in both the US and Canadian economies. Oil sands investments constitute billions of dollars in spending, and the economic benefits radiate far beyond the borders of Alberta to the rest of Canada and the United States. In the United States new activity arises in many sectors, for example building huge dump trucks and tires, manufacturing massive steel pipes and sophisticated process equipment, and engineering and building both small developments and megaprojects. The Canadian Energy Research Institute (CERI) projected that over the

*Both are members of the North Atlantic Treaty Organization (NATO), and in addition Canada and the United States have jointly run since 1958 the North American Aerospace Defense Command. Canadian armed forces are currently deployed in Afghanistan and have participated with the United States and other NATO forces in this mission since 2001.

next 15 years, in a higher growth scenario (production growth about 10 percent below our high-growth estimate) oil sands activities could add more than 340,000 new jobs to the US economy and contribute over $30 billion annually to the US GDP.*

## ENVIRONMENTAL FOOTPRINT ASSOCIATED WITH OIL SANDS DEVELOPMENT

Although oil sands have a larger environmental footprint than many other sources of oil supply, the gap is not always as large as portrayed.

- **GHG emissions.** On a well-to-wheels basis GHG emissions from oil sands are approximately 5 to 15 percent greater than the average crude oil consumed in the United States.** This calculation includes emissions from oil extraction, refining, distribution, and combustion of the refined products. On a well-to-wheels basis the majority of emissions are created when the fuel is combusted in a vehicle. The well–to–retail pump part of the emissions (before combustion of fuel in a vehicle) account for 20 to 30 percent of the total life-cycle GHG emissions. Some analyses have asserted that Canadian oil sands have well–to–retail pump emissions many multiples higher than the average crude oil consumed in the United States. This is not true of the typical or average oil sands development. For example IHS CERA's comparison of 11 publicly available life-cycle analysis studies found that fuel produced from oil sands mining has average well-to–retail pump emissions 1.3 times the average for fuel consumed in the United States. Similarly, fuel produced from oil sands utilizing SAGD has average well–to–retail pump GHG emissions about 1.7 times larger than the average fuel consumed in the United States. Oil sands are not alone; they are part of a group of higher carbon-intensity crudes consumed within the United States, including Venezuelan heavy crude oil; Nigerian crude oils; and crude oils from mature assets that require steam for enhanced oil recovery such as California heavy oil. Also certain fields in the Gulf of Mexico and the Middle East have comparable GHG emissions.

- **Water use.** Most types of energy production use water, including the oil sands. Net water use in oil sands production averages four barrels of water per barrel of bitumen for mining operations and 0.9 barrels of water per barrel of bitumen for in-situ production.*** Conventional oil uses 0.1 to 0.3 barrels of water per barrel of oil produced, while oil produced through enhanced oil recovery can use up to 70 barrels of water per barrel of oil. Oil alternatives can also be water intensive: ethanol from nonirrigated crops is comparable to oil sands mining, and options like coal-to-liquids can use 10 barrels of water per barrel of product. The key factor in water demand for all forms of energy is local availability of water and competition with other water uses. For example for oil sands mining local availability of water is an important issue. Oil

**The Impacts of the Canadian Oil Sands Development on the US Economy,* CERI, October 2009.
**The range is based on the average of the life-cycle GHG values reported by 11 publicly available life-cycle studies. In 2009 the Alberta Research Council published two additional studies comparing oil sands GHG emissions to those from other crudes. These studies are not incorporated within this analysis. Inclusion of these new studies and other new research on oil sands GHG emissions are the topic of the next IHS CERA Oil Sands Dialogue report.
***Net mining water use includes water from site runoff and mine dewatering, in addition to water from the Athabasca River. River withdrawals are approximately 2.5 barrels of water per barrel of bitumen.

sands mining operations rely on the Athabasca River for water. The water issues rise and fall with the river itself, for the river is seasonal, with much lower flow in winter than in summer. Thus, water availability is important in the winter when less water is available. The current volume of water allocated to users of the Athabasca is now approaching the winter withdrawal limits. As mined oil sands production increases, more water storage will be needed to reduce the need for additional river withdrawals in the winter months.

- **Land disturbance and reclamation.** About 20 percent of currently recoverable oil sands reserves lie close enough to the surface to be mined. The current footprint of mining operations is about 200 square miles (518 square kilometers), or about 2 percent of the greater Houston, Texas, metropolitan area. Direct land disturbance from mining results in a total loss of the ecological character of the disturbed land during the period of the mining operation. After the mining is complete, operators are required to reclaim the lands. Although reclamation is ongoing, to date the rate of land reclamation has not kept pace with the rate of disturbance. This is largely because of the arc of development of mining operations—it can take many years to finish mining an area so that reclamation can begin. Although slow, land reclamation has been in line with the expectations set forth in the projects' approved reclamation plans.

  About 80 percent of the recoverable oil sands deposits are too deep to be mined and are recovered using in-situ thermal processes. Direct land disturbance from in-situ production disturbs about 2 to 3 percent more land than conventional oil developments.* Like conventional developments, land disturbed by in-situ developments must be returned to its predevelopment state. Although the scale of degradation associated with in-situ development is relatively small compared to mining, fragmentation of the forest decreases the populations of some animal species, which tend to leave an area while human activity occurs.

- **Tailings.** Oil sands mines produce waste material called *tailings*; the waste materials have been difficult to reclaim and have grown larger than projected. In approximately 40 years of commercial oil sands development, the industry has produced nearly 1 billion cubic meters (35 billion cubic feet) of these fluid fine tailings, and the ponds that contain these tailings and other mining waste cover nearly 30 percent of the area currently affected by mining. As the size of the tailing ponds has grown, the public has become more concerned about potential leakage of tailings to the environment and hazards to waterfowl that land on the ponds. To address this issue, in 2009 the Alberta government introduced a new directive enforcing targets for reductions in tailing accumulations. If the goals of this new directive are met, it would reduce the rate at which future tailing accumulations grow.** Although the rate of growth is expected to

*Although a number of developments were considered, IHS CERA estimated the extent of disturbed land using aerial photographs and project approval maps for typical sites: SAGD at Devon Jackfish, conventional oil from the Fletcher Leduc-Woodbend, and conventional gas from EnCana Strathmore. The analysis did not include potential indirect land impacts.

**The directive requires that 50 percent of the clay and silt produced from the oil sands ore after July 2012 be removed from tailings ponds and made solid enough to support heavy equipment traffic. Oil sands operators have submitted plans, and technical solutions to reduce tailings and meet this directive are still being developed.

slow, overall volumes of tailings are still projected to grow with production growth from new mining operations.

- **Regulatory landscape.** Oil sands are a highly regulated industry. At a project level government regulation of oil sands activities is as robust, if not more so, than in many other oil-producing regions in the world. However, given the scale of current and potential future activity, the total impact of all of the cumulative development on the region's air, water, land, and biodiversity needs to be considered. To address this, in 2008 the Alberta government introduced the Land Use Framework, which aims to impose regional limits for air, water, and land use.*

- **Limits to growth.** If growth from current production levels were to reach the 2030 high growth projection (5.7 mbd), a number of growth limits must be addressed. Examples include these issues: water management practices must advance to minimize consumption of fresh water from the Athabasca River during winter months, the pace and scale of tailings management and site reclamation must increase, and local infrastructure must be developed in a timely manner. The high growth case requires a doubling in the rate of annual new productive capacity growth; therefore project execution must speed up to meet this growth projection.

## CONCLUSION

In September 2009 US Secretary of Energy Stephen Chu requested a National Petroleum Counsel study on the topic of "The Prudent Development of North America's Natural Gas and Oil Resources." The scope of the study considers the possible size of energy reserves and future productive capacity in a North American context, highlighting how oil sands as well as other sources of North American supply are being considered within US energy policy. Not only are North American energy sources being considered uniquely, but possibly so too are the environmental implications. In early 2009 Canada and the United States announced the "Clean Energy Dialogue." The Dialogue signals the potential for increased levels of collaboration between the two nations, working jointly to find solutions to environmental challenges while securing the energy required for future growth.

Energy security needs do not have to be at odds with the environment. Innovation in oil sands has been a constant theme. As in the past, ongoing investment in research, advancements in new extraction techniques, and improvements to existing methods should be expected. Both the US and Canadian governments, in collaboration with the industry, can play an important role in developing new technologies. Government support is important in providing funding to accelerate the development of new technologies. As production levels increase, new technologies are needed to reduce GHG emissions, water and energy use, and the scale of land disturbance and to increase the pace of land and tailing pond reclamation. A collaborative approach among all stakeholders will enable the full potential of this world-

*The Alberta Land Use Framework is developing regional plans defining economic, environmental, and social outcomes from development; it will integrate provincial policies and provide the context for land-use decisions at the regional level. A cumulative effects management approach will be used to manage the combined impacts of existing and new activities within each region of the province.

class resource to be realized in a sustainable manner, a resource that is just next door from the United States—the world's biggest oil consumer.

## REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Calgary on February 4, 2010, providing an opportunity for oil sands stakeholders to discuss perspectives on the key issues related to the role of oil sands in US energy supply. 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.

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- TransCanada

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- US Environmental Protection Agency
- UTS Energy Corporation

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Mr. Hobbs is a member of the Scientific Advisory Board of the Fondazione Eni Enrico Mattei. Prior to joining IHS CERA Mr. Hobbs had two decades of experience in the international exploration and production business. He has directed projects in Asia, South America, North America, and the North Sea. He has led major international investment and asset commercialization operations. Based in Cambridge, Massachusetts, Mr. Hobbs holds a degree from Imperial College.

**James Burkhard,** Managing Director of IHS CERA's Global Oil Group, leads the team of IHS CERA experts that analyze and assess upstream and downstream market conditions and business strategies. His team also develops and maintains detailed short- and long-term outlooks for global crude oil and refined products markets. Mr. Burkhard's expertise covers geopolitics, world energy and economic conditions, and global oil demand and supply trends. He works closely with IHS CERA clients in assessing how market, economic, and political risks could change the competitive environment. He also works with companies to assess business opportunities in both the upstream and downstream sectors. Mr. Burkhard was the project director of *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030,* a comprehensive IHS CERA study encompassing the oil, gas, and electricity sectors. He is currently leading a new initiative, the IHS Global Scenarios to 2030, which covers global economics, security, and geopolitics and focuses on the energy and automotive industries. He was also the director and coauthor of the recent IHS CERA Multiclient Studies *Growth in the Canadian Oil Sands: Finding the New Balance* and *Potential versus Reality: West African Oil and Gas to 2020.* He was project advisor to the IHS CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.* Mr. Burkhard is also the coauthor of CERA's respected *World Oil Watch,* which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Before joining IHS CERA Mr. Burkhard directed infrastructure projects in West Africa for the United States Peace Corps and was a field operator for Rod Electric. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

**Jackie Forrest,** IHS CERA Director, Global Oil, was the Study Manager for IHS CERA's recent Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance.* Ms. Forrest has more than a decade's experience in the definition and economic evaluation of refining and oil sands projects. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products. As the research lead for IHS CERA's Oil Sands Dialogue and Capital Costs Analysis Forum—Downstream, she is responsible for analyzing and monitoring emerging strategic trends related to oil sands projects. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

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*Future of Clean Energy*. Before joining IHS CERA Mr. Brady was a consultant in the oil industry, focusing on downstream regulatory issues including the transition to ethanol in the California gasoline market. Mr. Brady holds a BA from Amherst College and an MA from Johns Hopkins School of Advanced International Studies.

**William R. Veno,** IHS CERA Senior Director, Global Downstream, is an expert on crude oil and refined product markets, on refining and marketing, and on energy economics and strategy. Mr. Veno is a leader of IHS CERA's global refining and marketing research activity, with particular expertise in North American refined product demand, the transportation sector, and refined product pricing. Mr. Veno is a research leader of IHS CERA's *Driving the Future Forum: Transportation for the 21st Century*, specializing in light-duty vehicle fleet modeling and analysis. He performed the downstream market analysis for IHS CERA's recent study *Growth in the Canadian Oil Sands: Finding the New Balance*. He contributes to IHS CERA's quarterly *World Refined Products Outlook* and coordinated the oil demand analysis for the IHS CERA Multiclient Study on global energy scenarios, *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030*. He directed the IHS CERA studies *Gasoline and the American People 2007, Global Oil Trends,* and *Westward Flows and Refiners' Woes: The Growing Role of Imports in US Gasoline Suppl*y. Prior to joining IHS CERA he directed the Oil Service at an international forecasting company, where he was responsible for analysis of world and US oil markets and for crude and product price outlooks. He has conducted numerous studies for clients in the oil and energy industries and for national governments, including evaluations of refined product demand, refinery production and supply logistics, global geopolitical events, economic trends, and regulatory policies on oil markets. He has participated in several National Petroleum Council studies, including analyses of petroleum product supply, the cleaner fuels value chain, and fuel inventory dynamics. Previously Mr. Veno was Senior Petroleum Economist at Petróleos de Venezuela (USA) in New York, responsible for short- and long-term oil market analysis for the US and global markets, and had similar responsibilities as a Senior Analyst with Conoco and the US Department of Energy. Mr. Veno holds a BS from the University of Notre Dame, an MS from Dartmouth College, and an MS from Columbia University.

**Adebola Adejumo,** IHS CERA Consultant, has over eight years' experience spanning petroleum engineering and investment banking. Mr. Adejumo's expertise includes field development planning, cost estimation, and economic and uncertainty analysis of hydrocarbon assets. He has led and participated on several projects, including a major oil company's opportunity assessment in the Caspian, hydrocarbon fiscal contract modeling, due diligence and evaluation of resources for acquisition, and other lending transactions. He has delivered technical papers on issues involving marginal field development, resource availability, and gas flaring. He holds an MSc from Texas A&M University and an MBA from the Bauer College of Business, University of Houston.

# What is different about differentials?

Understanding the price of oil in western Canada

17 December 2020

**Kevin Birn**
Vice President

Crude Oil Markets | **Strategic Report**

# Contents

# What is different about differentials?

## Understanding the price of oil in western Canada

**Kevin Birn,** Vice President[1]

A crude oil differential is the difference in price that can emerge as a result of variations in composition (also known as quality) and location among crude oils. In western Canada, differentials are of great interest because the value of heavy, sour crude oil—Canada's largest source of crude oil export—typically obtains a price lower than many commonly traded US and global benchmarks. In fact, so common is the perception that Canadian crude is lower value that "discount" is used synonymously with differentials. But there is a big difference: differentials are not the same as discounts. But what gives rise to the differential in western Canada, and what factors influence it? Understanding these dynamics is key to understanding the value of Canadian oil.


### Key messages

- Differences in the price of crude oil exist globally because production can occur distant from refineries, incurring transportation cost to market, and because crude oil is not homogenous, which affects the price refineries are willing to pay.
- Differentials tend to be smaller for offshore, waterborne crude oils than for inland crudes. Overland transportation tends to be more costly and less liquid (lower volume) than marine transport, which can give rise to more pronounced localized price disparity.
- Western Canadian production is both inland and distant to market, which contributes to sustained price differentials for heavy and light crude oil. However, differences in inland North American supply and demand and crude quality contribute to larger differentials for heavy versus light crude oil in western Canada.
- Canadian light crude enjoys strong inland demand relative to supply, typically travels shorter distances to market, and has a similar quality compared with WTI—the principal North American benchmark crude. Assuming pipeline transport, lighter crude oils in Alberta should obtain prices between $3 below and $2 above WTI.
- Western Canadian Select (WCS)—western Canada's principal heavy, sour benchmark crude oil—has a larger quality differential to WTI compared with western Canadian light oil, and it typically must travel farther to market and incur higher transportation costs. Assuming western Canadian heavy crude oil is able to reach US markets by pipeline, it should obtain $9–15/bbl less than WTI.
- Delays in the expansion of pipeline export capacity have contributed to wider differentials and lower prices in western Canada than otherwise would have been expected. Over the past half decade (2015–19), IHS Markit estimates WCS alone obtained, on average, at least $3/bbl less than would have been expected.

—17 December 2020


1. Special thank you to Ashok Dutta for his contributions to this report.

**About this report**

**Purpose.** A crude oil price differential is the difference in the price of crude oils that can emerge as a result of quality and location differences. In western Canada, differentials are of great interest because the value of heavy, sour crude oil—Canada's largest source of crude oil export—typically obtains a price lower than many commonly traded US and global benchmarks. In fact, so common is the perception that Canadian crude is lower value that "discount" is used synonymously with differential. But there is a big difference: differentials are not the same as discounts. This report seeks to answer what gives rise to the differential in western Canada, what factors influence it, and what should be the price expectation.

**Context.** Since 2009, IHS Markit has made public some of its research on issues surrounding the development of the Canadian oil sands. This report is part of a series of reports from the Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

**Methodology.** IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

**Disclaimer.** This report explores the pricing relationship among western Canadian crudes and inland US and global benchmark crudes. Please note that price relationships can be very complicated. The purpose of this report was not to present a forecast. Rather, it was to discuss the factor influencing the differentials in the western Canadian oil market. As a result, a number of simplifications and a wider set of assumptions were used than would be deployed in the IHS Markit pricing outlook. For example, this report made use of average pipeline tolls, as well as committed and uncommitted tolls, to arrive at estimate pricing relationships among benchmark crudes. Actual differentials faced by an individual producer may also vary and can and do fluctuate. This report should not be taken as fixed viewed, nor is the information contained in this report substitute for a detailed crude valuation study or analysis.

This report has four sections.

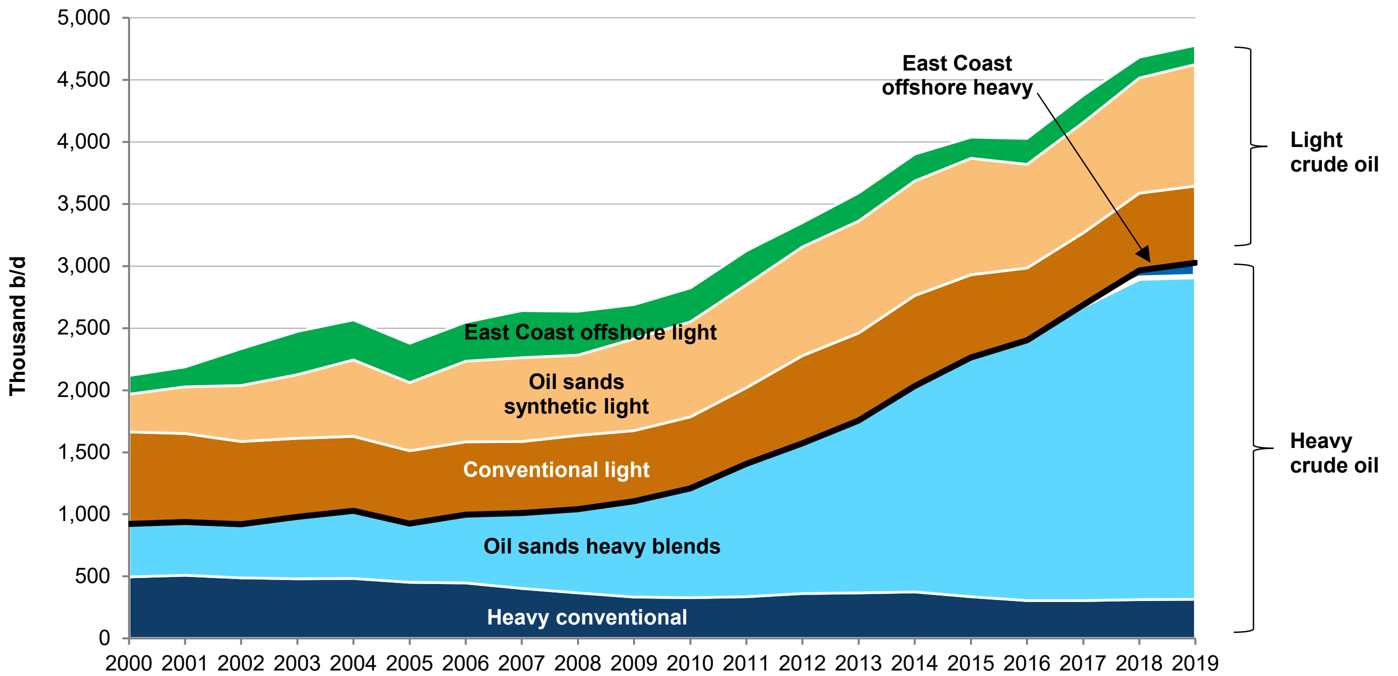
- Introduction
- Understanding a crude oil price differential
  - Crude quality complicates comparisons
  - Transportation distance reduces prices (more so for inland crudes)
- Understanding the price of oil in western Canada
  - Inland demand narrows the differential for western Canadian light oil
  - Greater supply increases distance and differentials for western Canadian heavy oil
- The opportunity to lower western Canadian differentials

## Introduction

For more than a decade, Canada has been among the fastest-growing producers of crude oil in the world. Although growth has come from all grades—light to heavy—heavy, sour crude oil from the Canadian oil sands has dominated (see Figure 1). From 2000 to 2019, Canadian oil sands output rose more than 1.5 MMb/d, pushing Canadian production above 4.6 MMb/d. This growth made Canada the fourth-largest producer in the world.

Figure 1

**Composition of Canadian production, 2000–19**




Source: IHS Markit



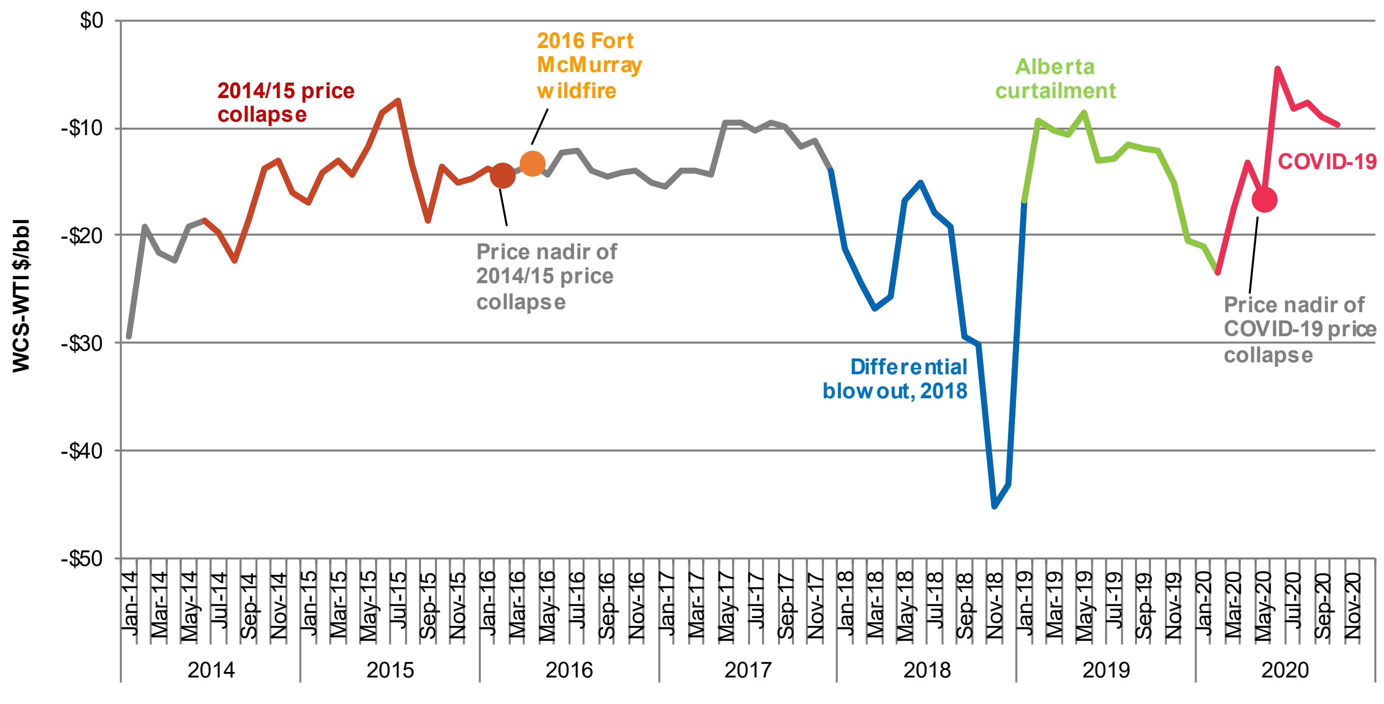
Throughout this period, pipeline projects have been proposed in anticipation of rising production. However, all the projects have faced opposition and, ultimately, delay. As a result, export pipeline capacity has struggled to keep up with demand.[1]

During the past three-quarters of a decade, there were several periods when western Canadian output exceeded regional demand and takeaway capacity. During these periods, the price of oil in western Canada fell relative to inland US and global oil prices. The most infamous episode to date occurred in the fall of 2018, when differentials for heavy crude widened to as much as $50/bbl below WTI, the inland US light oil benchmark (see Figure 2). Absolute prices fell into the midteens—worse than during the nadir of the global price collapse in early 2016. Only the most recent price rout driven by the COVID-19 global oil demand shock sent Canadian prices to a lower level.

1. The history of the timing of western Canadian pipeline infrastructure was covered extensively in the IHS Markit Strategic Report Pipelines, Prices, and Promises: The story of western Canadian market access.

Figure 2

**Western Canadian heavy, sour differential to WTI, monthly average 2014–20 year to date**




Source: Argus Media, IHS Markit



Because crude oil is not homogenous, its price will vary depending on where it is produced and on its quality. These price differences are known as a "basis differential," or simply "a differential." In western Canada, differentials are of great interest because the value of heavy, sour crude oil—Canada's largest source of crude oil export—obtains a price lower than many commonly traded US and global benchmarks. In fact, so common is the perception that Canadian crude is lower value that "discount" is used synonymously with differential. But what gives rise to the differential in western Canada, and what factors influence it?

This report seeks to explain the factors that help set the price of oil in western Canada. In addition to this introduction, the report has three sections. In the first section, we explain how both crude oil quality and transportation cost influence crude oil price differentials. In the second section, we explore how these factors influence the price of oil in western Canada. The final section briefly discusses the outlook and opportunities for western Canadian differentials.

It should be noted that in extremely low price environments such as during early 2016 or over 2020, price differentials typically narrow. However, these episodes do not represent average or typical operating conditions. Comparisons made in this study make use of historical pricing relationships, which are likely to resume once the market recovers from the current oil surplus.

Throughout this report, there are references to various terminology and characteristics that differentiate crude oil quality. For more information on the characteristics that give rise to quality differences among crude oils, please see the box "Crude quality primer."

## Crude quality primer

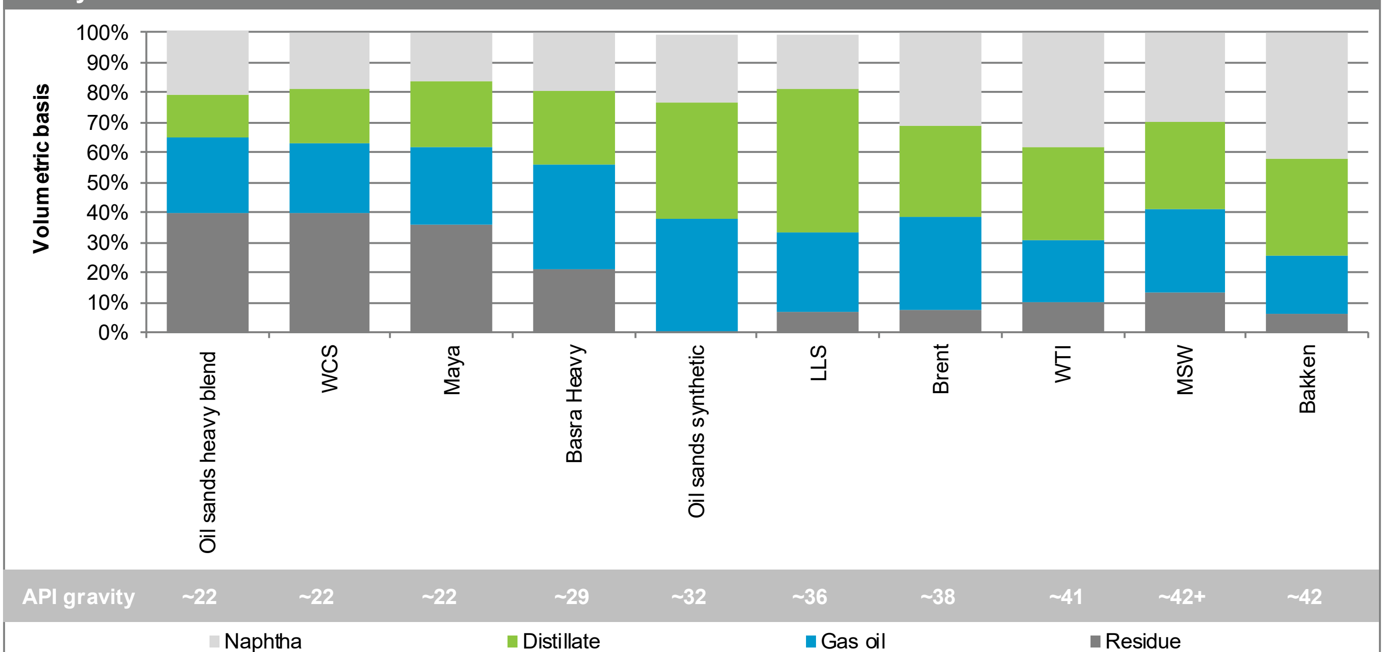
Crude oil is not homogeneous. Crude oils have different densities (which determine whether a crude is described as “light” or “heavy”) and have varying levels of impurities such as sulfur (which give rise to crude oil descriptors such as “sweet” [low sulfur] or “sour” [high sulfur]).

Density is by far the most common metric of quality, which is often measured according to API gravity. Based on IHS Markit definitions, light crude oil has an API gravity of 32° or greater. Heavy crude oil has an API gravity 24° or less (with the API gravity for extra-heavy crude oil below 10°). Medium crudes have an API gravity between light and heavy crudes. IHS Markit considers crude oil that has a sulfur content that is less than 1% by weight a sweet crude, and all levels above this are considered sour.

Differences in the density of crude oil result from the composition of hydrocarbons found in each crude oil. Within any given barrel of crude oil, there are various fractions, or groupings of hydrocarbons that distill or boil at distinct temperature ranges. Naphtha is the lightest fraction and boils at a lower temperature. Gasoline is generally derived from naphtha. Kerosene (jet fuel) and diesel are found in the distillate range, boiling at temperatures between 180 degrees Celsius (°C) and 350°C. Vacuum gasoil and residue are viscous materials that nominally boil between 350°C and 550°C and above 550°C, respectively. These heavier fractions with higher boiling points require additional processing (via catalytic or thermal processes) to be converted into lighter fractions of distillate and naphtha, which can then be converted into higher-value products. Less complex refineries (facilities that lack additional heavy crude oil processing technology) will not be able to process these heavier fractions into lighter products. As a result, they will pay a premium for lighter crude oil because its heavier fractions are minimal. By contrast, more complex refineries—facilities that have invested in specialized units capable of converting heavy fractions to light products—will seek out crude oil with larger fractions of heavier molecules. Because of the complexity and cost required to process heavier crude oils, they typically are cheaper than lighter crude oil.

Figure 3

**Assay of select crudes**




Note: Crude assays vary. Values are approximations and vary by cut point and reservoir quality, which does vary across a play and over time. Estimates are assembled from various sources and adjusted based on feedback.

Source: Derived and adapted from IHS Markit, Energy Information Administration (EIA), BP Global Energy Trading, and CrudeMonitor.ca

## Understanding a crude oil price differential

A crude oil price differential is influenced by the transportation cost between markets and differences in the composition of the oil—often referred to as quality—between the crude oils being compared. This section breaks down how these factors can contribute to price variations among crude oils.

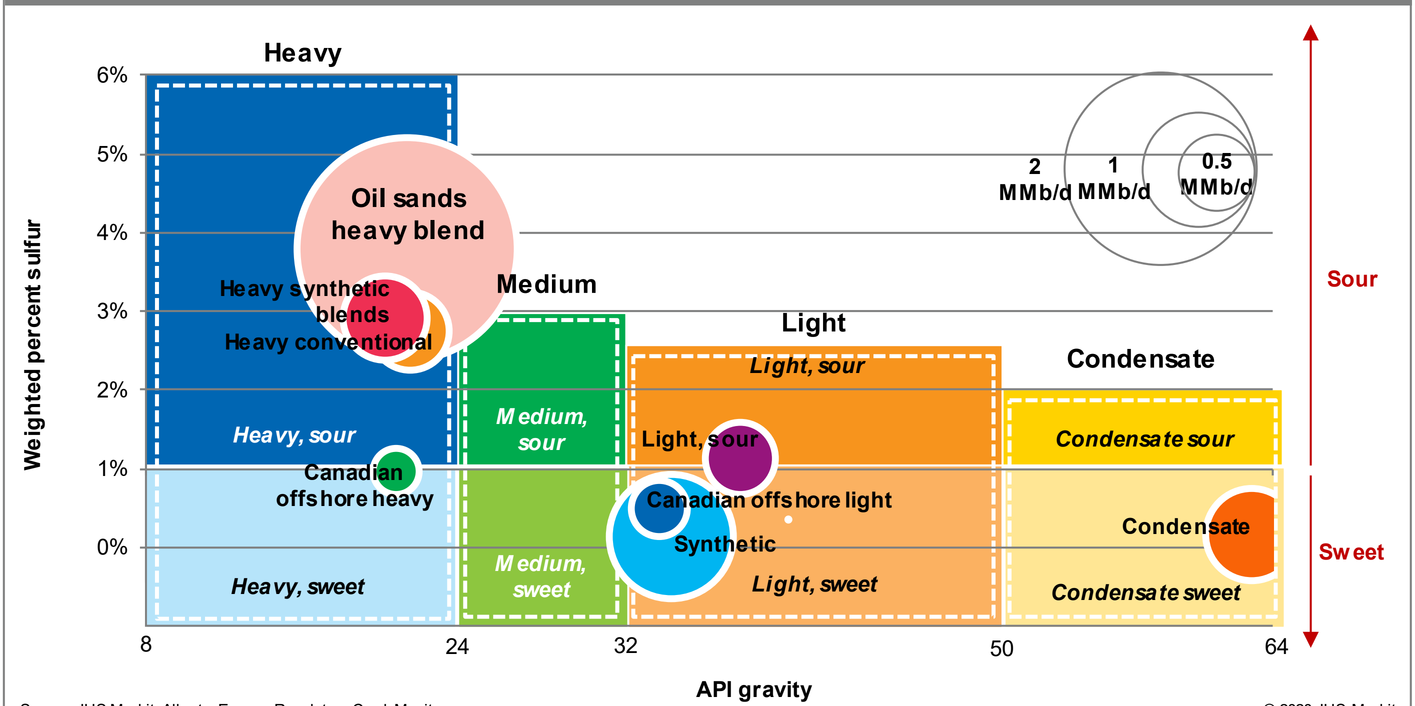
### Crude quality complicates comparisons

Crude oil is not homogenous. Crude oil is most commonly differentiated by density—light or heavy, which relates to the distillation of the crude oil—and the presence of impurities such as sulfur, acid, or solids, which gives rise to qualifiers such as "sweet" (low-sulfur crude) or "sour" (high-sulfur crude). For more information, see the box "Crude quality primer."

Canada produces a diversity of crude oils, from ultralight natural gas condensates (crude oil that exists in vapor form in the reservoir and becomes liquid at atmospheric temperatures and pressure) to extra-heavy, sour crudes (crude oil that is semisolid at room temperature) (see Figure 4). In western Canada, nearly every form of onshore extractive technology is in use, from conventional wells, to multistage horizontal stimulation (hydraulic fracturing), to large-scale oil sands mining projects. Although there is a great variety of crude oils being produced, growth has been dominated by heavy, sour crude oil from the oil sands.

Figure 4

Distribution of Canadian crude by quality




Source: IHS Markit, Alberta Energy Regulator, CrudeMonitor.ca

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Heavier crude oil generally contains a greater share or fractions of heavier hydrocarbons, which have higher boiling points, such as residue (boils at temperatures over 550°C). These heavier fractions require specialized capital-intensive refinery processing units to be converted into higher-value refined product, such as gasoline or diesel. Additional refining units, such as hydrotreaters, are required to remove sulfur and other impurities to meet product specifications. These differences in processing requirements influence the cost of processing, the yield of refined products that can be derived from various crude oils, and their market—refineries capable of converting heavier, more complex crude oil into higher-value refined product. These factors, in turn, influence the value refiners place on a given crude oil and thus the price it obtains.[2]

In this way, variations in crude quality can result in price differences among crude oils, even within the same region. The price difference is smaller for similar-quality crudes and is greater for ones with larger differences in properties.

### The light-heavy differential

A commonly cited metric to measure the degree of quality price disparity is known as the *light-heavy differential*, which compares the price of a light, sweet crude oil against heavier, more sour crudes.

The *light-heavy differential* is important for refineries since it influences the economics of processing heavy versus light crude oil. This metric is of particular interest in Canada because it is a major producer of heavy, sour crude.

A generally accepted measure of the global *light-heavy differential* is that of Mexican Maya (Maya)—a globally traded waterborne heavy, sour crude oil, priced in the Gulf of Mexico—and Louisiana Light Sweet (LLS)—a light, sweet crude oil traded at Louisiana oil hubs.[3] During the past five years (2015–19), the price difference between LLS and Maya averaged just over $7/bbl.[4]

### The quality differential is not static

Although the price difference between two geographically approximate crude oils will be dominated by variations in quality, the price that refineries assign to quality differences can change over time. For this reason, history may not always be a reliable predicator of the future value of a quality differential. Some more common supply and demand factors that have influenced quality differentials in recent years include

- **Global oil price.** Quality differentials tend to widen in higher prevailing oil price environments and narrow in lower price environments. For example, from 2012 to 2014, when the price of oil averaged about $100/bbl, the LLS-Maya light-heavy differential averaged about $11/bbl, or about $4–5/bbl greater than in recent years when absolute prices were lower. During 2020, the spread has narrowed further—averaging below $4/bbl—but this result has also been supported by reductions in the availability of heavy, sour crude oil discussed below.[5]

- **Changes in refined product prices.** The value of refined products, such as gasoline, diesel, or fuel oil, fluctuates based on changes in consumer supply and demand. This variation influences the relative value of different crude oils based on the underlying fractions of refined product that can be derived from them. A notable example is the International Maritime Organization's (IMO) implementation of the sulfur dioxide regulations for bunker (ship) fuel, which was anticipated to reduce the demand, and thus value, of high-sulfur fuel oil. This result, in turn, was expected to affect the price of heavier, more sour crude oils globally, because they tend to have a larger fraction of sulfurous heavy bottoms (like residue).

2. According to "last barrel" economics, the price of a grade of crude oil is determined by how it is valued in the marginal refinery configuration. For example, if the incremental barrel of heavy crude oil is valued in a "cracking" refinery (with no coking or ability to process the heaviest hydrocarbons), that barrel will be valued less than by a refinery with deeper processing units. Persistently lower prices for heavy crude relative to lighter crudes in turn provide the economic incentive for a refiner to invest in additional heavy crude oil handling, such as construction of a coking unit.

3. WTI—a light, sweet crude oil priced in Cushing, Oklahoma—is the most commonly cited light oil in North America. However, because it is located inland and distant to tidewater, it can face additional transportation-driven differentials, which is why we chose to focus on two waterborne crude oils.

4. The Maya crude oil benchmark price is based on a formula managed by Pemex. In the short term, this formula can result in some divergences from what would normally be anticipated, but over the long term, for Maya to maintain its competitiveness against other crudes, it generally converges or tracks other globally traded crudes.

5. Based on the first 10 months of 2020.

- **Changes in the relative supply of light and heavy crudes.** Since late 2018, the global light-heavy differential narrowed. During this period, the LLS-Maya differential averaged about $5/bbl, which is about $3/bbl less than the 2015–17 average. During 2020, this narrowing has been helped by lower prices; additionally, the world has seen further reductions in availability of heavy, sour crude oil. The reduction in available heavy, sour crude oil has occurred owing principally to the accelerated decline in the availability of Venezuelan heavy, sour crude oil and ongoing declines in Mexican and Iranian output. This narrowing was helped along until 2020 by rising light, sweet crude oil production from the United States. The combined effect put upward pressure on the price of heavy, sour crude oil and downward pressure on lighter crudes—narrowing the difference in price between the two.

- **Changes in global refining conversion capacity/utilization.** The availability of heavy residue conversion capacity (e.g., delayed coking)—required to economically process heavy crude oil—also influences the light-heavy differential. Increases in conversion capacity boost demand for heavy crude oil, relative to supply. Delayed coking capacity has historically been added in cycles, as refiners respond to the price signals triggered by increases in heavy crude supply.

### Estimating quality differentials

IHS Markit estimates the quality differential among different crude oils based on the value of the refined product that can be obtained from processing these crudes in different refinery configurations and in different regions. The two bookends for this range are derived from the relative value that a less complex refinery may realize versus the value obtained in a more complex refinery. A less complex refinery obtains less value from processing a heavier crude oil, because of its inability to convert the heaviest fractions into higher-value refined product, leaving them with a greater share of the barrel of oil as lower-value intermediate product. Conversely, a more complex refinery would put greater value on heavier oil because it is able to convert the heaviest fractions into higher-value refined product such as gasoline and diesel. In general, this situation provides more complex refineries greater flexibility, but it also requires a higher degree of capital investment.

In this way, the properties being compared are more complex than a simple measurement of density (light or heavy), because the fractions of even similar density crudes can vary (see the box “Crude quality primer”).

Although quality differentials will fluctuate according to underlying market forces, as discussed above, they tend to do so within the bookends set by the value obtained from low-complexity and high-complexity refineries. Should the value of heavier crude oil relative to lighter crude oil widen sufficiently, the potential savings in feedstock cost can incentivize even less complex refineries to process more heavy crude, even if it means they are left selling more lower-value intermediate product such as heavy fuel oil.[6] Conversely, should the value of heavy crude oil appreciate, it can push even more complex refineries to consume lighter grades, since there is greater cost associated with processing heavier oils.[7] In this way, the value of the quality differential tends to track between these two goalposts.

## Transportation distance reduces price (more so for inland crudes)

Oil-producing regions are often remote from consuming markets, and the crude oil must be transported to market, which comes at a cost. Transportation cost affects the price producers obtain for their crude, because producers must pay to move their crude oil to market to compete with other crudes for refinery space.

All things being equal, the greater the distance a producing region is from the market or demand center, the greater the cost and the lower the price a producer will receive for their crude. This situation is known as a

6. Most of the low-complexity or “light” crude oil refiners will face technical limits in their ability to process heavy oil (i.e., most cannot run 100% heavy crude).

7. Although complex refineries are more flexible in the crude slate they can process, they can still face technical limitations in their ability to process high percentages of light crude oil (i.e., a complex refinery designed to process heavy, sour crude cannot run 100% of light crude).

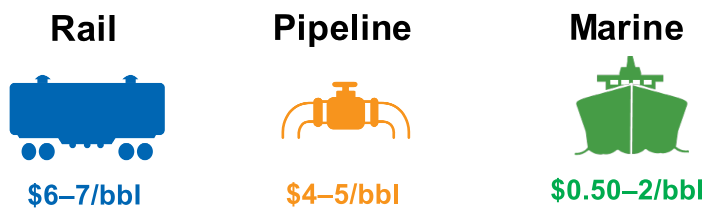
netback price (the price obtained in a distant market, netted back to the producing region by subtracting the transport cost). Price differences between regions can result, even for similar-quality crudes.

However, things are not always equal. Different regions may have access to different modes of transport, and different modes of transport have varying operational characteristics and ultimately different costs. These distinctions influence transportation-driven price differentials between regions.

Figure 5 provides a simplified cost comparison of the major modes of long-distance crude oil transport. It is important to note that even within each mode of transport shown in Figure 5, there are further differences that exist that influence the relative cost structure. For example, vessel size, pipeline size/gauge, or crude train configurations (dedicated trains known as unit trains, or mixed-use trains known as manifest trains) affect the cost of transport. Additional factors such as routing (whether the movement must move through more or less congested areas) and contractual terms (such as fixed long-term contracts versus common carrier) also influence cost.

Figure 5

Simplified cost comparison to transport a barrel of oil approximately 1,000 miles




Note: Cost ranges presented are approximations, and actual cost can and will vary depending on committed/fixed term or uncommitted/spot contracts, density of crude oil, distance, scale such as pipeline gauge, tank car specification, and/or vessel size/class, etc. Pipeline and rail costs based on North American transportation systems.
Source: IHS Markit



**Transportation differentials tend to be smaller for waterborne crudes compared with inland crudes**

For globally traded waterborne crude oils, price differences due to transportation tend to be relatively contained. Crude oil production on or near tidewater benefits from access to the relative efficiency and flexibility of marine transport. Marine transportation enables crude oil to move freely to the highest price point globally—away from regions that become temporarily oversupplied and that would provide lower prices. This result is known as arbitrage and helps stabilize the price differences between regions. For these reasons, the price differences among globally traded (waterborne) crude oils tend to be relatively small. For example, the variation in the price of key waterborne light, sweet crude oil benchmark prices around the world was on average less than about $3/bbl in 2019 despite thousands of miles between regions (and even some subtle quality differences).[8]

For onshore, inland crudes, more costly and less flexible transportation modes contribute to larger sustained transportation-driven price differences between regions. For example, in 2017, when the North American market was largely free of any pronounced transportation disruptions or bottlenecks, the price of light, sweet oil in western Canada, as measured by the Mixed Sweet Blend (MSW) benchmark, traded on average about $5 below waterborne LLS in the US Gulf Coast (USGC) offshore—a distance of about 2,000 miles (3,200 km) compared with some global waterborne distances listed above that easily exceed about 4,000 miles (6,500 km).

We make reference to 2017 to illustrate the pricing relationship that would be expected in the absence of transportation system bottlenecks. There were well-documented transportation system bottlenecks that occurred in western Canada and in inland US markets in 2018 and 2019 that affected transportation-driven pricing relationships.[9]

8. Comparison is based on $63; LLS, St. James (FOB): $63; Brent, North Sea: $64; Arab Light, Sidi Kerir (FOB): $64; Bonny Light, Nigeria (FOB): $66; Hibernia, Whiffen Head: $64. Source: Argus Media.

9. In 2018, western Canada experienced a significant oversupply situation owing to insufficient export pipeline capacity that led to a dramatic reduction in western Canadian prices compared with other inland US and global benchmarks. In 2019, western Canada registered increasing demand for higher-cost crude-by-rail transportation from the basin, and in the United States transportation bottlenecks from the Permian Basin to Cushing, Oklahoma (Cushing), and the USGC contributed to additional price dislocations for inland crude oils. To be fair, 2017 is not without issues as well; however, these issues arose more from regional supply than transportation infrastructure.

## Understanding the price of oil in western Canada

All Canadian crude oil tracks globally traded crudes, subject to transportation cost and quality differences. In Canada, most production occurs inland, in western Canada, distant to and/or with limited access to marine export terminals. As a result, there is a greater reliance on overland transport—principally pipelines, but crude by rail has also increased in recent years. The inland location of Canadian producers comes at a cost, with pipeline transport a relatively more expensive and less flexible transportation option than marine transport.

The size of the price differential for Canadian producers depends on how far (and by what mode) crude oil must be transported to market and any quality differences among the crudes being compared. Western Canadian light oil has experienced a smaller transportation-driven differential to globally traded crude oil than heavy crude because Canadian light crude typically travels a shorter distance to its end market. Because of these differences, the pricing relationships for western Canadian light and heavy oil are discussed separately.

### Inland demand narrows the differential for western Canadian light oil

Western Canada produces more than 1 MMb/d of light oil. Although most of it is consumed domestically within western Canada, production still exceeds regional demand and must be exported. The most significant geographically approximate market is the US Midwest, which is accessed by pipeline. From a price-setting standpoint, the US Midwest has become the most important market for western Canadian light oil because this is where it competes with other sources of supply from North Dakota, Texas, and elsewhere for refinery space.

As shown in Figure 6, reaching the US Midwest requires western Canadian producers to cover the transportation cost to deliver their crude oil into that region. As a result, the price of western Canadian light crude oil tracks the price of light oil in the US Midwest—linking the two market prices by the cost of transport. Under existing pipeline infrastructure and tolls, it costs about $3–4/bbl to transport western Canadian light oil from central Alberta (Edmonton area) into the Chicago area.[10]

US Midwest refinery demand for light oil is greater than can

Figure 6

**Western Canadian light crude oil path to market**


Source: Argus Media/ IHS Markit: ER2020-55



10. The actual cost varies by loading area, destination, and commercial terms of the transport such as whether the shipper has a long-term contract or is uncommitted. There are several on-ramps where western Canadian and northern US production can access Canadian export pipeline systems that generally run southeast from Alberta to Manitoba.

be supplied from Canada and other Northern Tier crudes, such as from North Dakota, and crude oil must be delivered north from the market hub in Cushing, Oklahoma. Unlike Northern Tier crudes, which are landlocked with all the pipeline infrastructure pointing south, Cushing is a major crude oil trading hub. Crude oil in Cushing can flow north into the Midwest or south to refineries or export terminals in the USGC region. As a result, Midwest refineries must compete with USGC and global export opportunities for crude oil in Cushing. To obtain the crude oil they need, refineries in the US Midwest must pay the prevailing price in Cushing and then the cost of transport into the US Midwest. Based on pipeline transport from Cushing to the Chicago area, the price of light oil in the US Midwest must be, on average, about \$2–3/bbl higher than Cushing. In turn, depending on the prevailing tariff rate, the pipeline transport toll sets the price of oil in Cushing at about \$3–4/bbl below the price in the Houston area, where the price is more closely tied to globally traded waterborne crude oil (or \$4–5/bbl to offshore markets, which would reflect an additional cost of about \$1/bbl to reach global markets). Accounting for all these relationships implies that the price of light oil in western Canada should, on average, track about \$4–6/bbl below comparable crudes in offshore USGC (\$3–4/bbl – \$2–3/bbl + \$3–4/bbl + \$1/bbl) and just over \$1–2.5/bbl compared with Cushing. In 2017, this relationship fit well with MSW averaging about \$49/bbl and LLS at \$54/bbl—a difference of about \$5/bbl.

It is important to note that the availability of crude oil pricing information can vary by region. For example, there are currently no posted light crude oil benchmark prices in the Chicago area—the central refining area of the US Midwest. In fact, there are no Canadian light crude oil benchmark prices tracked south of the 49th parallel. WTI is tracked in multiple locations and is a commonly accepted comparable crude oil that can be used for comparison with Canadian lights, but there can be quality differences. On the other hand, Canadian heavy oil enjoys greater liquidity in the United States and is tracked by price reporting services at multiple locations: Western Canadian Select (WCS), the principally western Canadian heavy, sour crude oil benchmark is reported at Hardisty, Cushing, and Houston. For more information on benchmark prices, see the box "Benchmark crude oil prices."

**Benchmark crude oil prices**

Benchmark crudes are crude oils that serve as common transparent markers as to the value of crude oil being bought or sold in a particular location. There are many benchmark crudes that are used to represent different regions or quality grades. The most common ones globally are Brent, which is a waterborne light crude oil produced and traded in the North Sea, and WTI, which is the US inland light crude oil marker traded in Cushing, Oklahoma. Some examples of other common benchmarks include OPEC basket, LLS, Dubai, and Urals.

Many benchmark crude prices are tracked at multiple locations (in addition to their principal location), and for some, the pricing can be for future possession. It is important to note the terms of each benchmark to ensure an apple-to-apple comparison. Unless otherwise stated, the benchmark prices used in this report are for their principal geographical location (e.g., WTI in Cushing, WCS in Hardisty).

Even though there are various crude benchmarks by quality and geography, the variety of crude oil globally is even more diverse, and often transactions will be linked via a differential to a specified benchmark crude at a specified geography.

This situation is true in western Canada as well. For example, WCS is a purposely designed cocktail of heavy, sour oil sands crude (bitumen); light, sweet crude oil; condensate; and even some synthetic crude oil (SCO) that was created to provide greater western Canadian heavy, sour oil price transparency. Although WCS has become the dominate benchmark for western Canadian heavy, sour crude oil, most heavy, sour crude oil production is a blend of bitumen and condensate—a dilbit. These heavy oil sands blends have subtle differences to WCS, which would generally result in dilbit obtaining a modestly lower value or facing a larger quality difference to other crudes than WCS (see Figure 3).

### Comparing western Canadian light oil to WTI

Although transportation to the US Midwest and regional supply and demand dynamics are likely the most important factors influencing the price of light oil in western Canada relative to globally traded crudes, quality also plays a role. Within North America, the most common basis of comparison for inland crude oil is to WTI, Cushing.

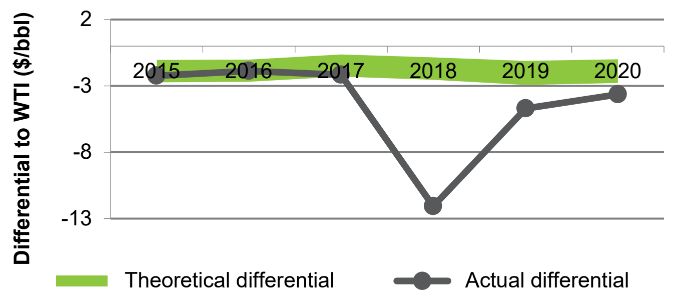
In western Canada, there are two primary light crude oil benchmark crude oils—MSW and SCO. As shown in Figure 3, these two crude oils have distinct properties compared with each other and with WTI. MSW has modestly larger fractions of gasoil and residue and less naphtha compared with WTI. Although the larger share of gasoil can result in greater yield of higher-value diesel over gasoline, this result is more than offset by the larger fraction of lower-value residue. SCO, on the other hand, is a unique product of upstream oil sands upgraders, which do the work of heavy oil processing units typically found at downstream refineries. In upgrading, the heaviest fraction found in bitumen, residue, is converted into lighter products. As a result, less complex refineries can process SCO and yield an greater share of higher-value product than WTI.

Putting aside transportation cost and considering only the value a refinery can derive from these crudes, on average MSW should obtain \$0–1 below WTI (closer to -\$0.25 to -\$0.75), while SCO should obtain a \$1–3/bbl premium. These differences in value are known as the quality differential.

All else being equal, the collective differences in crude quality and transportation can explain the price of oil in western Canada. Despite geographical distance of nearly 1,500 miles (2,300 km), MSW in Edmonton should be expected to trade, on average, between \$1 and 3/bbl beneath WTI in Cushing (accounting for net pipeline transport of \$1–2/bbl and a quality discount to WTI of \$0–1/bbl). Meanwhile, the higher-quality SCO in Edmonton should fetch between \$1/bbl below and \$2/bbl above WTI in Cushing (net pipeline transport of \$1–2/bbl and a quality premium to WTI of \$1–3/bbl). Figures 7 and 8 provide a more detailed comparison of the expected differential range for MSW and SCO based on pipeline transport and adjusting for quality differential each year (estimated by refining value) versus the actual differential over the past five years as derived from Argus Media.[11]

Figures 7 and 8

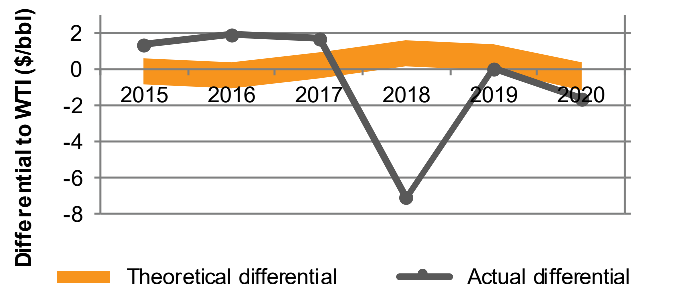
**MSW-WTI theoretical differential to actual differential**




Note: Differential estimated based on anticipated refinery value and pipeline transportation cost. Actuals derived by IHS Markit using Argus Media. Note the theoretical range based on estimated transportation tolls and refinery value, which will change from year to year. These figures make use of a wider set of potential transportation tolls and refinery valuation than deployed in the IHS Markit pricing methodology to provide a wider range of potential outcomes. Estimate for year 2020 based on first nine months.

Source: Argus Media, IHS Markit © 2020 IHS Markit

**SCO-WTI theoretical differential to actual differential**




Note: Differential estimated based on anticipated refinery value and pipeline transportation cost. Actuals derived by IHS Markit using Argus Media. Note the theoretical range based on estimated transportation tolls and refinery value, which will change from year to year. These figures make use of a wider set of potential transportation tolls and refinery valuation than deployed in the IHS Markit pricing methodology to provide a wider range of potential outcomes. Estimate for year 2020 based on first nine months.

Source: Argus Media, IHS Markit © 2020 IHS Markit

It is clear from Figures 7 and 8 that the market reality can vary from expectation. The ranges shown in both figures are not forecasts but an expected outcome based on a range of pipeline transportation cost and the differences in the relative value of the products a refinery may obtain from the crude oils in each year.[12]

11. As previously discussed, quality differentials are not static and contribute to changes in expected value from year to year but generally hold within the broader average differential discussed in this paragraph.

12. Playing with potential refinery yields and/or configurations can accentuate the range of potential values, but they should generally center on the range shown.

In reality, additional factors, such as unanticipated shifts in global supply and demand or unforeseen transportation system upsets, also play an important role. For example, in both Figures 7 and 8 the differential range shown assumes that production is able to reach market by pipeline. The large divergence between expectations and reality in 2018 was the result of supply overtaking available pipeline export capacity, which led to a temporary but dramatic reduction in western Canadian prices. In addition, SCO is produced from only four facilities, which makes each operation material to overall supply. In 2016, 2017, and 2018, there were incidents that contributed to a temporary tightening of SCO supply, which likely supported some of its price strength (although the impact in 2018 was muted by larger regional oversupply).[13] The year 2020 had its own set of very unique market fluctuations as a result of the global pandemic.

## Greater supply increases distance and differentials for western Canadian heavy oil

Over the past decade (and more), western Canadian heavy, sour crude oil supply growth has outpaced light oil. Western Canada produced about 3 MMb/d of heavy supply in 2019.[14] As supply grew, it overtook demand in the traditional markets of western Canada, the US Rockies, and the US Midwest. In response, export pipeline infrastructure expanded, and lengthened, to reach increasingly distant markets in Canada and farther south in the United States. The USGC region, which was already the largest heavy, sour oil–consuming region in the world, has provided a readily available market for growing Canadian supply.[15] However, the longer distances to market contribute to a greater transportation-driven differential and smaller netback value compared with western Canadian light oil. Western Canadian heavy oil currently competes against globally traded heavy crudes of similar quality in the USGC region.

As shown in Figure 9, this result makes the transportation costs all work in the same direction for heavy oil and increases the transportation-driven differential to global crudes compared with western Canadian light crude oils.[16]

The majority of existing western Canadian heavy crude oil pipeline export infrastructure transits through the US Midwest, with

Figure 9


13. In 2016, the Fort McMurray wildfire impacted several integrated mining operations that market SCO. In 2017 and 2018, there were unanticipated outages at the Syncrude facility.

14. Heavy conventional, blended bitumen, and heavy SCO.

15. See the IHS Markit Strategic Report Looking north: A US perspective on Canadian heavy oil.

16. The exception was in 2020, when reductions in upstream supply were so acute that the price-setting market temporarily moved further north.

additional capacity able to move supply farther south, onto Cushing and then the USGC. Canadian crude then competes for refinery space against globally traded waterborne crudes in the Houston, Texas, and Port Arthur, Texas, refining hubs. Assuming pipeline transport, the cost to move Canadian crude to the USGC includes $4–5/bbl to transport heavy oil from western Canada to the US Midwest, then $1–3/bbl from the US Midwest to Cushing, and then $3–4/bbl from Cushing to Houston. In total, these costs imply Canadian heavy should track crude oil of similar quality in the Houston area by $8–12/bbl (depending on pipeline route and committed versus uncommitted contracts). Demand for heavy, sour crude oil in the USGC region exceeds available onshore supply, and offshore imports are required. To attract waterborne cargoes, the onshore price should be modestly higher (about $1/bbl) than waterborne crude oil to cover the cost of landing the crude oil relative to competition elsewhere in the world. Taken together, Canadian heavy, sour crude oil should trade about 7–11/bbl ($4–5/bbl + $1–3/bbl + $3–4/bbl – $1/bbl) below globally traded crudes of similar quality.

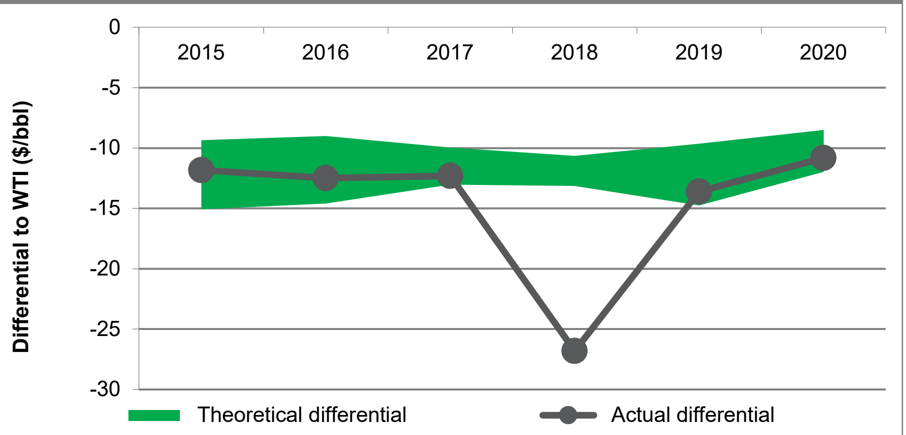
The most common basis of comparison for western Canadian heavy, sour crude oil to global crude oil of similar quality in the USGC region has historically been Maya. In 2017, WCS in western Canada traded down to Maya crude within the expected range averaging $8/bbl. Again, owing to transportation system limitations in both 2018 and 2019, the year 2017 was chosen for this illustration.

**The larger Canadian heavy-light differential**

Even though WCS will track globally traded crude oils of similar quality like Maya, the common basis of comparison for inland North American crude oils is to WTI in Cushing. In a very general sense, WCS in Alberta should tend to trade within $9–15/bbl less than WTI in Cushing (net pipeline transport of $5–7/bbl and quality discount to WTI of $4–7/bbl) (see Figure 10). Excluding the exceptional pipeline export situation that occurred in 2018, from 2015 to 2019 (thus also excluding COVID-19–led 2020 market impacts), WCS in Alberta obtained about $13/bbl below WTI, Cushing.[17]

Figure 10

WCS-WTI theoretical differential to actual differential




Note: Differential estimated based on anticipated refinery value and pipeline transportation cost. Actuals derived by IHS Markit using Argus Media. Note the theoretical range based on estimated transportation tolls and refinery value, which will change from year to year. These figures make use of a wider set of potential transportation tolls and refinery valuation than deployed in the IHS Markit pricing methodology to provide a wider range of potential outcomes. Estimate for year 2020 based on first nine months.

Source: Argus Media, IHS Markit



## The opportunity to narrow western Canadian differentials

Western Canadian production is inland and distant to market, which contributes to higher transportation costs and therefore larger differentials to benchmark crude markers than typically experienced by waterborne crude oils. Differentials for western Canadian heavy crude against light crude markers are accentuated by the fact that these barrels can only be processed efficiently by complex refineries. Together, transportation cost and quality differences have made differentials part of the western Canadian lexicon. Yet, in the public

17. The potential range of expected value is greater than the Canadian light comparison made earlier (for example, $9–15 for heavy versus $1–3 for MSW) because of a greater range of potential transportation costs and a wider potential variation in quality valuation.

dialogue around the value of western Canadian production there has been confusion about what level of differential is “normal” or to be expected.

There can be little doubt that a key source of this confusion is linked to the fact that differentials can be complicated to unpack—requiring an understanding of regional supply and demand, crude oil flows, transportation costs, and refinery valuations. Differentials can also be volatile—moving around from day to day—based on market forces.

In western Canada, however, uncertainty about the value of differentials is also linked to the region’s long-running struggle to bring online adequate pipeline export capacity. Pipeline export constraints have contributed to larger differentials, and lower returns for Canadian crude oil, than otherwise would have been expected. Although the impact on differentials has been sporadic, had there not been any transportation constraints over the past half decade (2015–19), IHS Markit estimates that western Canadian heavy crude oil would have obtained, on average, at least $3/bbl more compared with WTI, Cushing. The impact of this lost value over millions of barrels produced each day during the last past half decade is significant—about $14 billion (US dollars). Moreover, this estimate is likely conservative, since it is based on differentials only in excess of the uppermost bound of the anticipated range and only considers the impact on heavy, sour crude oil (see Figure 10).[18]

Looking forward, with a number of pipeline export projects now in construction, the opportunity exists for narrower differentials, on average, for the western Canadian market than over the past half decade. This would support greater price stability within the region and help prevent the abnormally wide differentials of the past half decade.

It is hoped that this report will shed some light and understanding on the factors that shape the price of oil in western Canada and the approximate value exports should obtain based on a free and functioning market.

18. The IHS Markit estimate is based on average daily differentials between WTI, Cushing, and WCS, Hardisty, from the start of 2015 to the end of 2019 as derived from Argus Media compared against a scenario in which the differential did not exceed $15/bbl—the upper bound of the range provided in the prior section. The estimated financial impact is based on value reduction associated with the abnormal differential each year from 2015 to 2019 multiplied by the annualized western Canadian heavy, sour supply less regional refinery consumption. It is reasonable to assume some producers with access to their own firm pipeline export capacity would have been able to insulate some of their production reducing the volume of exports exposed to abnormal differentials. Conversely, the estimated differential impact is likely greater than estimated. The use of $15/bbl was the maximum of the upper bound of the range during 2015–19 shown in Figure 10. Meanwhile, the average of the upper bound was just over $14/bbl, with the average of the actual differential, excluding the year 2018, nearly $13/bbl. Because WTI, Cushing, was subject to its own transportation bottlenecks during this period, a comparison was also made between WCS, Hardisty, and Maya, FOB. In this comparison, the estimated loss was greater. For these reasons, we view our estimate as conservative. This estimate also only considers the impact on heavy, sour crude oil and not exports of lighter grades.

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