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Why the Oil Sands?

How a remote, complex resource became a pillar of global supply growth

July 2015

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STRATEGIC REPORT

Canadian Oil Sands Dialogue | Special Report

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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.

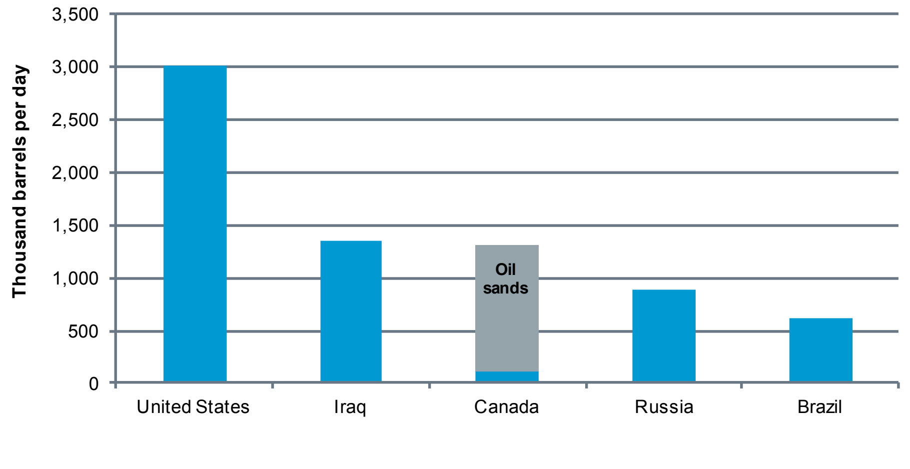
How has oil sands production growth continued, despite multiple challenges? Can output continue to expand—even when confronted with much lower oil prices?

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
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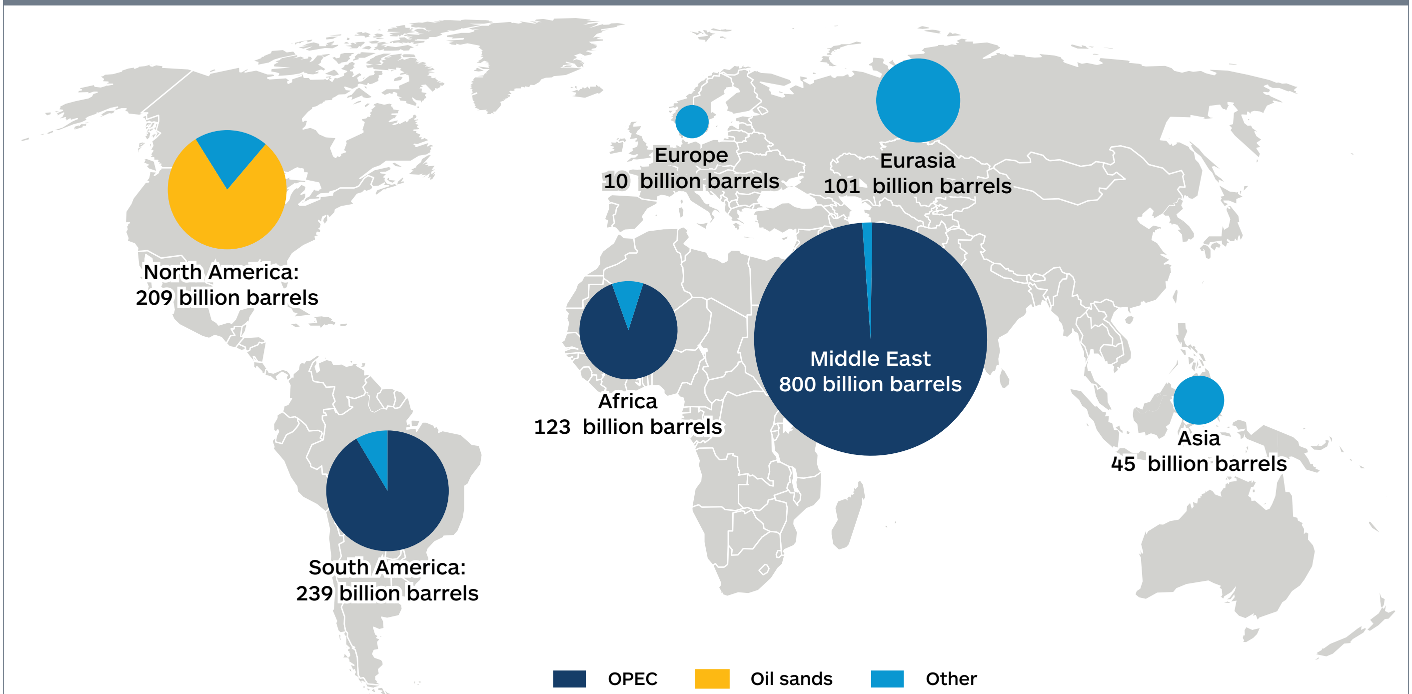
Innovation and market forces spurred oil sands development

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
© 2015 IHS: 50626-3

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.

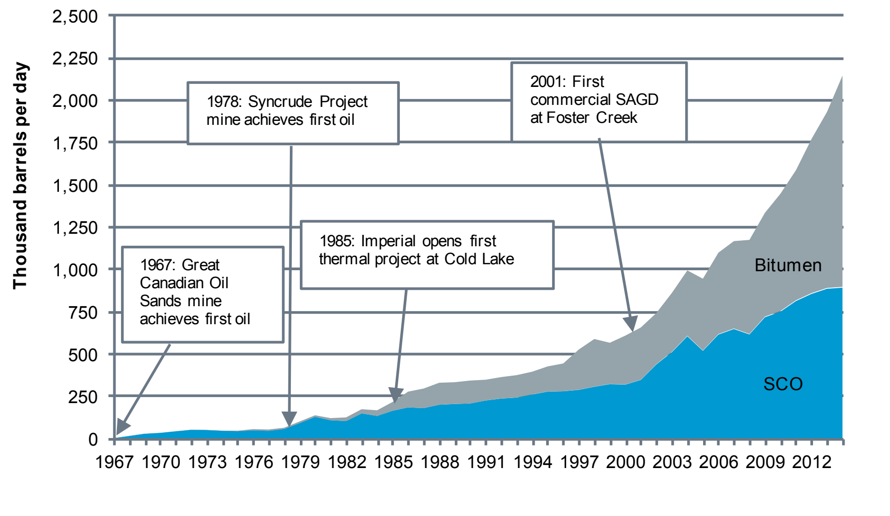
5. Hydrotransport also had the advantage of lowering the temperature (and therefore energy) in the separation process, which improved economics and greenhouse gas (GHG) intensity. Another large mining technology development during this period was a transition from bucket-wheel excavation to more reliable 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.

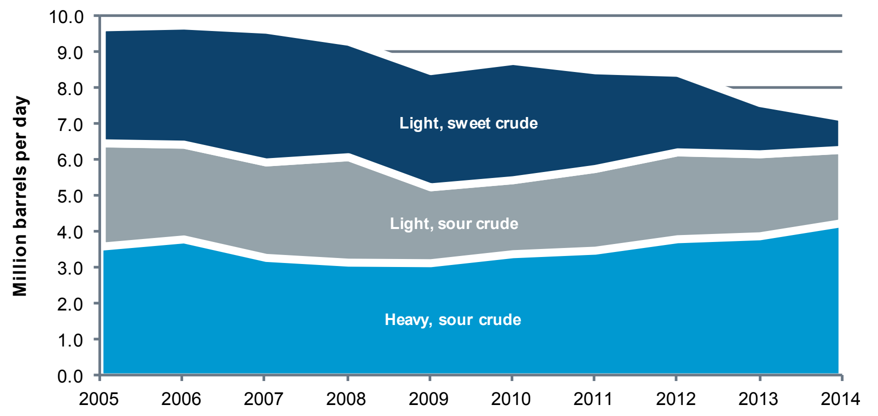
the United States' single largest source. A combination of growing Canadian and US supply led Canada to overtake the cumulative US imports from all of OPEC toward the end of 2014.[10]

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

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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.

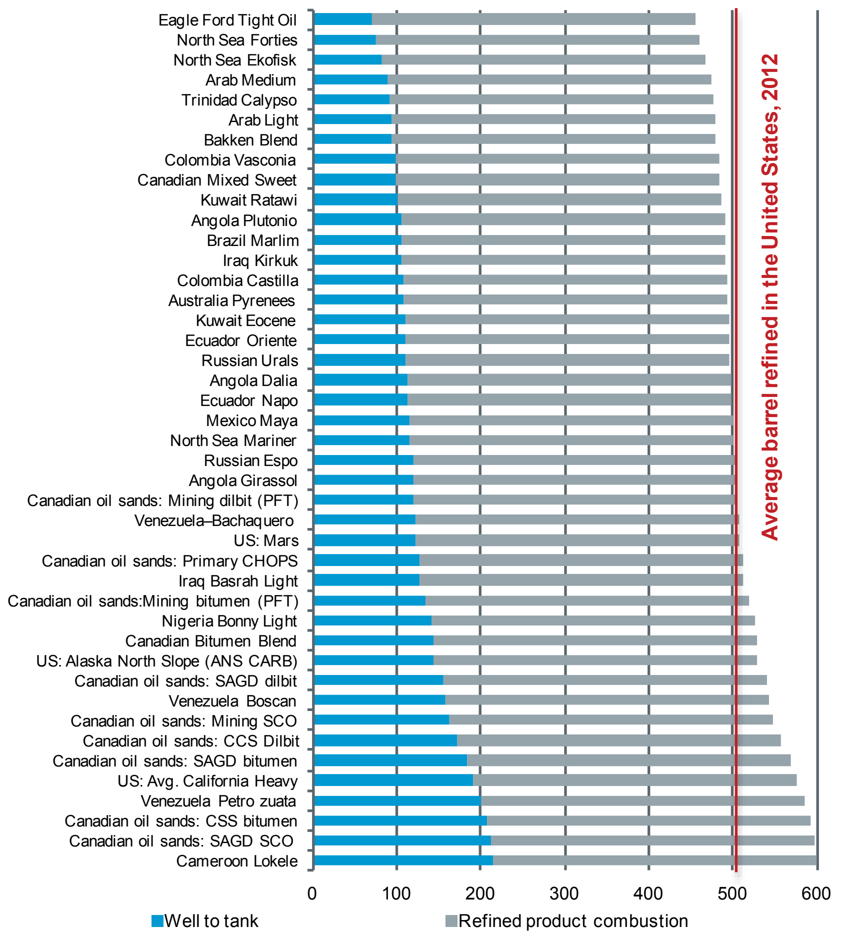
23. See Daniel Yergin, *The Quest: Energy, Security, and the Remaking of the Modern World,* Penguin Books, New York, 2012, Chapter 25.

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).

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.

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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- **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.

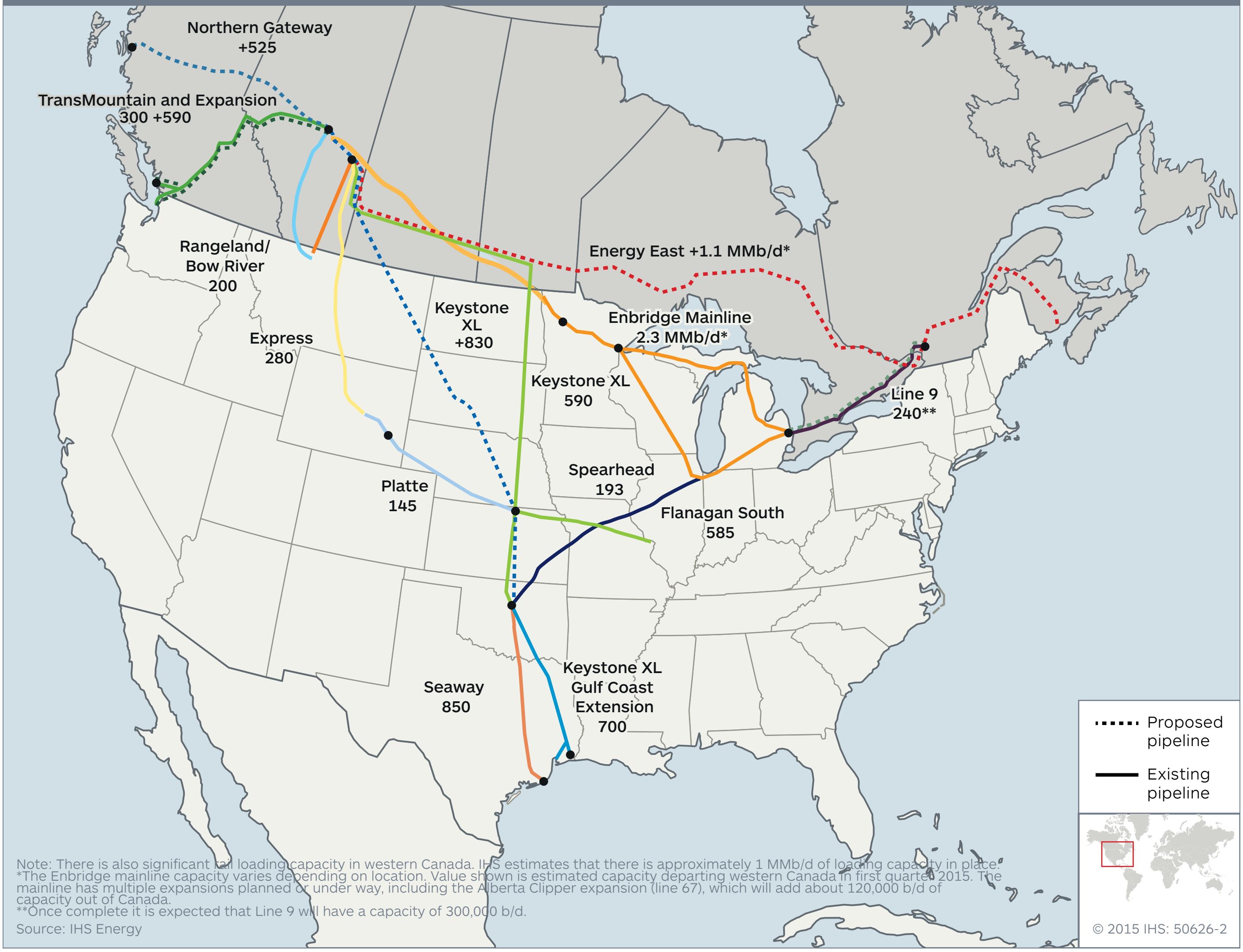
34. The southern leg of the pipeline, running from Oklahoma to the USGC, has already been built. This section did not require State Department approval because it did not cross an international border.

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.

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Canadian Natural Resources Limited

Canadian Oil Sands Limited

Cenovus Energy Inc.

ConocoPhilips Company

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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.

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