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?

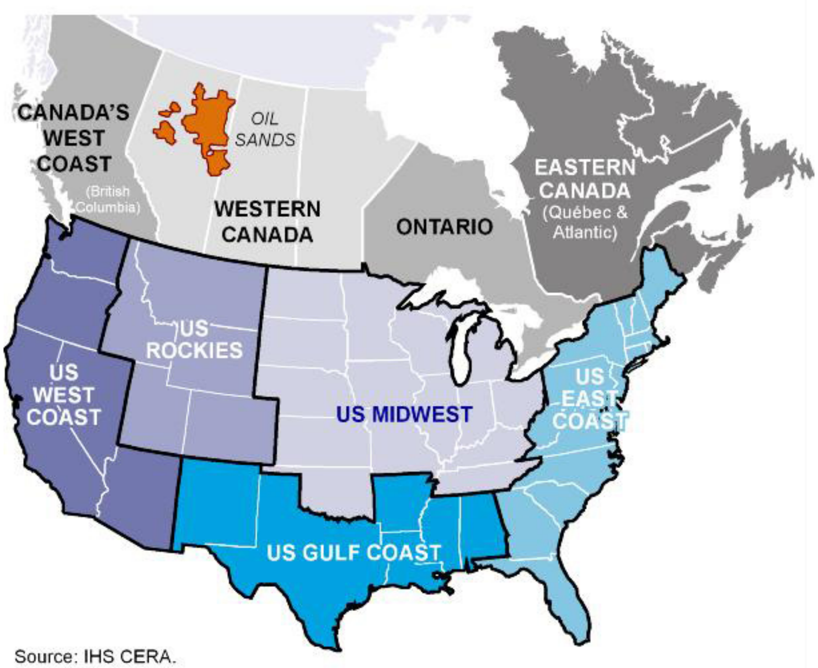
This section explains that even though Canadian producers are driven to expand their markets, the United States will remain the primary outlet.

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.
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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 Tight oil competition 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 Tight oil competition 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 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.

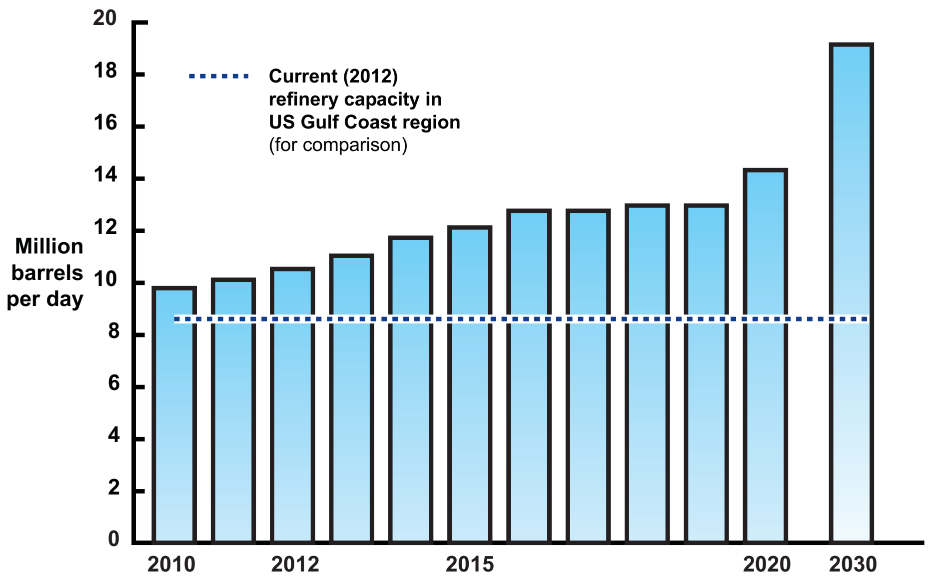
China's existing refining fleet has a capacity of about 10 mbd. Current refinery capacity is geared to light oil, so opportunities for SCO are greater than for heavy bitumen blends. In 2011 China imported nearly 1.4 mbd of light, sweet crude (similar to SCO), 2.6 mbd of light sour, and under 300,000 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.

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Total E&P Canada Ltd.

TransCanada Corporation

IHS CERA TEAM

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We also recognize the contribution of Carmen Velasquez, IHS CERA Associate Director, to this report.