IHS Markit™

A New Look

Extracting economic value from the Canadian oil sands

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Crude Oil Markets | **Strategic Report**

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About this report

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

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

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

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

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

Structure. This report has four sections:

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

A New Look

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Key implications

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

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

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

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

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

Part 1: Introduction

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

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

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

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

Table 1

Proposed Canadian heavy oil processing projects outside of Alberta

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

Source: Various sources and company publications © 2017 IHS Markit

The case for a new look

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

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

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

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

This report has four sections:

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

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

Part 2: Processing heavy oil

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

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

Primer: Canadian oil sands

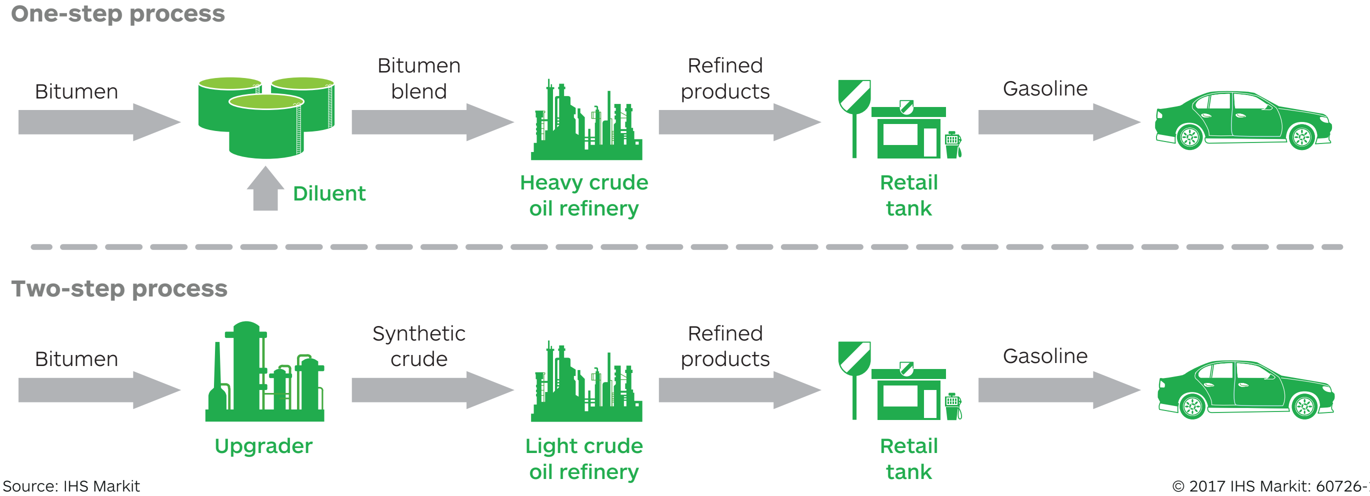
In its natural state, raw bitumen is solid at room temperature and cannot be transported by pipeline. For pipeline transport, bitumen must be either diluted with light oil into a bitumen blend or converted into a light crude oil called SCO.

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

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

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

Bitumen upgrading and refining



Source: IHS Markit

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

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

Economics of processing heavy oil

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

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

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

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

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

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

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

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

Why it costs more in Alberta

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

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

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

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

How capital costs have changed

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

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

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

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

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

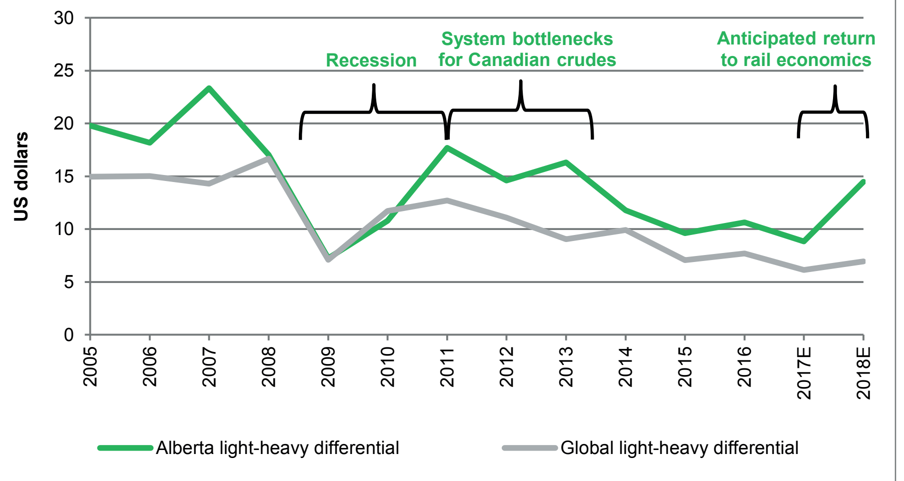
8. Temperatures in Alberta can range from over 80° Fahrenheit (F) (30° Celsius [C]) to −40°F (−40°C).

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

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

Figure 2

Global and Canadian light-heavy price differentials



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

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

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

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

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

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

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

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

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

All paths to market require pipelines

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

Part 3: Methodology

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

What follows is a brief description of our methodology.

Table 2

Project types and markets included in IHS Markit analysis

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

Source: IHS Markit © 2017 IHS Markit

Three options for processing heavy oil

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

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

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

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

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

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

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

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

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

A partial process to market

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

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

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

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

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

Summary assumptions

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

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

Table 3

Key assumptions for economic calculations

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

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

Source: IHS Markit

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

Part 4: Results

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

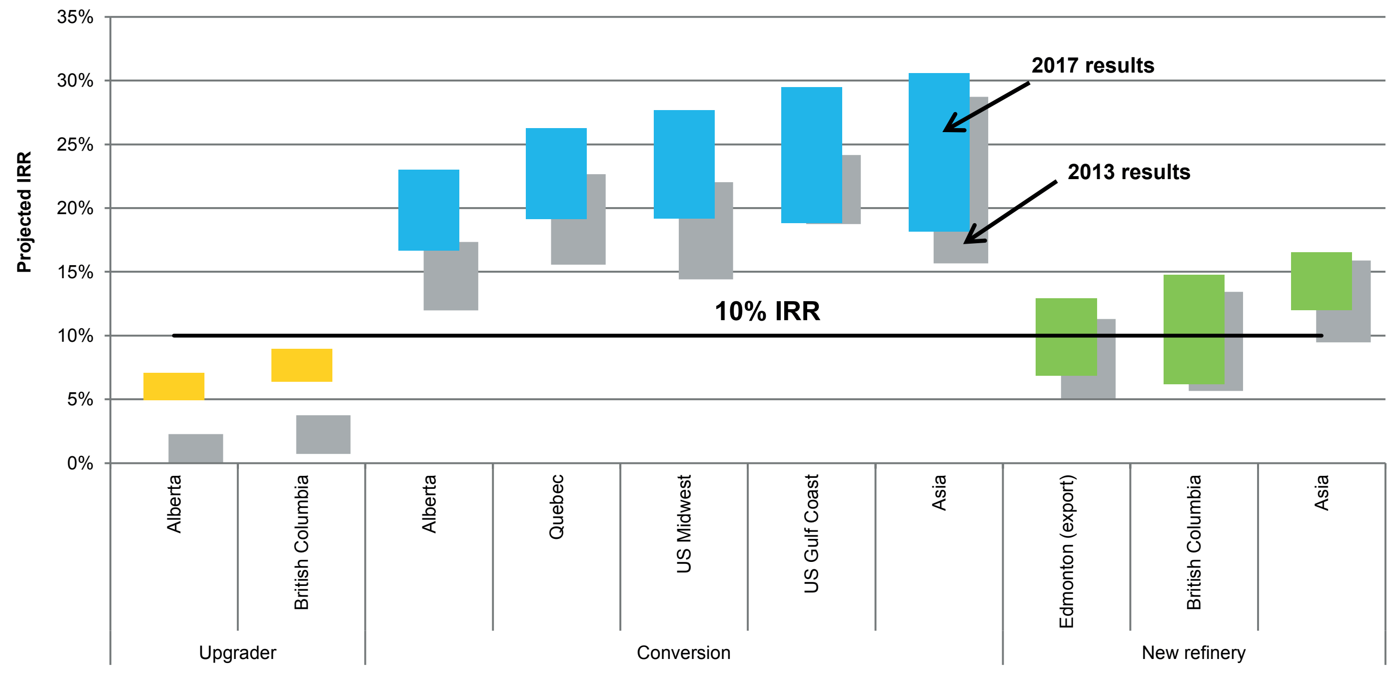
These results are best interpreted as a range of equally probable outcomes. Our study does not explore the comparative economics of alternative refinery configurations and/or grades of crude oil (i.e., light, medium, heavy, etc.). All cases are generic and are not configured or meant to replicate any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

Summary

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

Figure 3

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



Source: IHS Markit

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

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

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

Refinery conversions

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

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

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

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

Greenfield refineries

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

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

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

Upgraders

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

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

Concluding remarks

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

The IHS Markit team

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

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