Four years of change

Oil sands cost and competitiveness in 2018

April 2019

Kevin Birn
Vice President

Crude Oil Markets | **Strategic Report**

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Key implications

In the run-up to the oil price collapse of 2014–15, the expansion of the Canadian oil sands developed a reputation for cost escalation. More often than not, the bill for a new project came in well above the projected budget. In 2015, IHS Markit documented oil sands' history of cost inflation and the impact lower prices were having on reducing oil sands' cost structure. Four years later, this report provides a new look at the market environment and the price of oil required for the Canadian oil sands.

- **By many metrics, oil sands costs have fallen.** The cost to construct a new oil sands project may be up to one-third less than in 2014, and the cost to operate an oil sands project fell more than two-fifths from 2014 to 2018.
- **The price of oil required for an oil sands project—thermal or mining—to break even has fallen since 2014.** IHS Markit estimates the lowest-cost oil sands project—an expansion of an existing thermal operation—could break even in 2018 (putting aside the extreme volatility in late 2018) at about a WTI price of $45/bbl compared with more than $65/bbl in 2014. A mining operation without an upgrader required a WTI price approaching $100/bbl in 2014 compared with nearly $65/bbl in 2018.
- **Yet, investment in the Canadian oil sands has continued to decline.** In 2019, IHS Markit estimates new capital investment could be the lowest in 15 years at about $8 billion. This result is a significant change from levels in 2014, when investment approached $33 billion.
- **Local prices, not global prices, are contributing to uncertainty over the timing of further investments in the Canadian oil sands.** Insufficient pipeline capacity to deliver growing volumes of Canadian oil sands crude to market contributed to extreme price volatility in 2018. Western Canadian heavy oil averaged $27/bbl less than WTI in 2018, compared with $12/bbl in 2017, and ranged from as little as $11/bbl to more than $50/bbl beneath WTI.
- **A more modest oil sands growth scenario is taking shape.** From 2018 to 2030, IHS Markit expects more than 1 MMb/d of oil sands production growth. This result would put total oil sands output at about 4 MMb/d in 2030. This number equates to average annual additions of less than 100,000 b/d, compared with additions closer to 160,000 b/d over the prior decade.

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About this report

Purpose. In the years preceding the oil price collapse of 2014–15, the Canadian oil sands developed a reputation for cost escalation. More often than not, the bill for a new project came in well above budgeted cost. In 2015, IHS Markit documented the oil sands' history of cost inflation and the impact lower prices were having on reducing oil sands cost structure. Four years later, this report takes stock of the current state of oil sands costs. How have they changed? Why? What are the competitive implications?

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

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

Methodology. IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

Structure. This report has six sections.

- Introduction
- Costs are down
- The price of oil required to break even is down
- Local, not global, oil prices holding back the oil sands
- An uncertain investment climate
- A more modest oil sands growth scenario emerging

Introduction

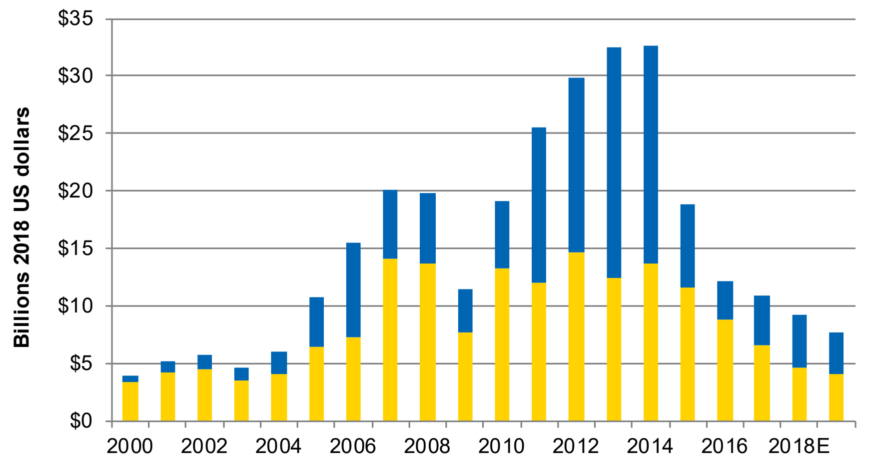
Although the global oil market remains volatile, there is a general sense that the worst of the low oil prices of recent years may be in the rearview mirror. Indeed, 2018 was marked by both a bull and bear market. Brent prices reached highs above $80/bbl and lows approaching $50/bbl. However, this was still an improvement compared with the sub-$30/bbl during the first quarter of 2016.

Although volatile, higher oil prices on average have allowed oil companies globally to begin to rebuild their balance sheets and resulted in an uptick in new investments in oil production.

Western Canada's oil sands, however, has seen investment continue to trend down. Since the 2014–15 oil price collapse began, most of the large oil sands projects in construction have been completed. Relatively higher oil prices in 2017 and 2018 encouraged the restart of the construction of projects deferred during the worst of the low prices. Operators have also advanced new capital efficiency initiatives aimed at improving reliability and output from existing operations. These initiatives include debottlenecking projects and investing in projects where excess capacity exists, utilizing that capacity to achieve higher output. All signs continue to point to a further deceleration in growth. In fact, investment in 2019 is expected to be the lowest in 15 years (see Figure 1).

Figure 1

Oil sands capital investment



Note: E = estimate.
Source: IHS Markit, Canadian Association of Petroleum Producers, Statistics Canada

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For detractors of the Canadian oil sands, this decline in investment confirms a view that the industry is too costly to compete. However, this view ignores the ongoing cost changes and the impact of the incredible price volatility, exceeding or in addition to global price instability, that has taken place in western Canada.

In many respects, concerns over oil sands costs are based on a historical reputation for being "high cost"—a by-product of rapid investment that preceded the oil price collapse of 2014–15. At the end of 2015, IHS Markit took stock of the efficiency gains the industry had made. We found that the industry had lowered costs, with the potential for more reductions. Indeed, when that report was issued the oil sands had yet to endure the worst of the low prices felt over the first half of 2016 (and more recently in late 2018). Through this period, the industry has continued to scrutinize existing operations and future projects for savings and adapt to a lower price environment.

This report revisits the prior report, "Oil Sands Cost and Competitiveness," released in December 2015. Now four years since 2014, how have costs changed? What does it now cost a project to produce, and what oil price is needed for a new project to break even?

Some of our methodology has changed slightly since that prior report, and subtle differences in our assessment between those years may exist. Throughout this report, we refer to various oil sands terms. See the box "Canadian oil sands primer" for definitions.

Costs are down

Since 2014, IHS Markit has tracked significant cost reductions in the Canadian oil sands. Two key components of oil sands production costs are the capital cost and operating cost.

Capital cost represents the up-front cost to develop, construct, or bring online a new facility. Capital cost is significant for an oil sands operation: it can range into the multiple billions of dollars, and for some of the largest mining operations, into tens of billions.

Canadian oil sands primer

The immensity of the oil sands is their signature feature. Current estimates place the amount of oil that can be economically recovered from Alberta's oil sands at 166 billion bbl, making it the world's third-largest proven oil reserve (after Saudi Arabia and Venezuela).

The oil sands are grains of sand covered with water, bitumen, and clay. The "oil" in the oil sands is bitumen, an extra-heavy crude oil with high viscosity. Raw bitumen is semisolid at ambient temperature and cannot be transported by pipeline. It must first be diluted with light oil or converted into a synthetic light crude oil. Different grades of crude oil are produced from bitumen.

Bitumen blends. To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. A common bitumen blend is dilbit—short for diluted bitumen—typically about 70% bitumen and 30% lighter hydrocarbons.

Synthetic crude oil (SCO). SCO is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. These units are called upgraders. SCO resembles light, sweet crude oil.

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

Mining. About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process, similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed and stockpiled for later use in reclamation. The layer of oil sands ore is excavated using massive shovels that scoop the material, which is then transported by truck to a processing facility. About half of production in 2018 was from mining. Mines can come with and without upgrading units.

- **Integrated mines.** The original mining operations all featured an integrated upgrader that transformed bitumen into higher-quality SCO.
- **Unintegrated mines.** The two most recently completed mining operations do not include an upgrader and, instead, market a bitumen blend.

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

- **Steam-assisted gravity drainage (SAGD).** This process has been the fastest-growing source of oil sands output and in 2018 accounted for 40% of total oil sands production.
- **Cyclic steam stimulation (CSS).** CSS was the first process used to commercially recover oil sands in situ. Growth of CSS has been outpaced by other extractive technologies, and in 2018 it accounted for less than 10% of total oil sands production.
- **Primary production.** The remaining oil sands production is referred to as primary production. Less viscous oil sands are extracted without steam using conventional oil production methods. Primary production made up nearly 4% of oil sands output in 2018.

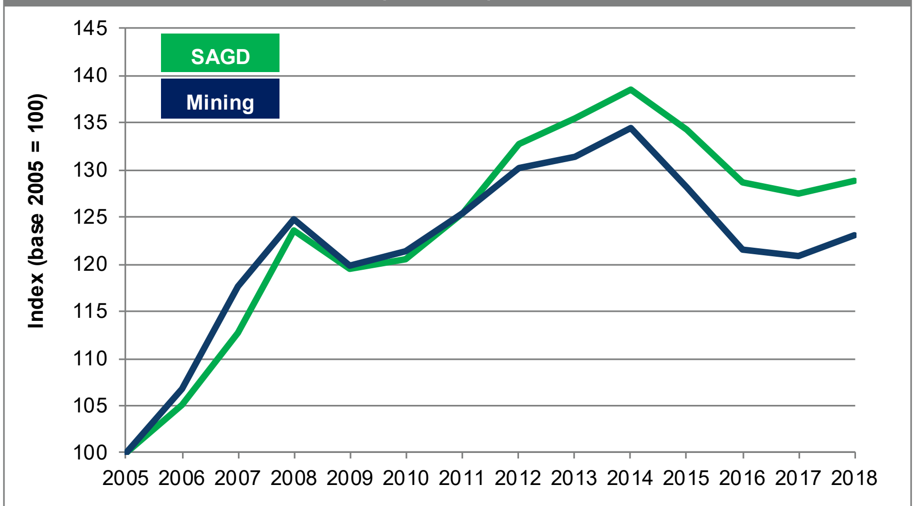
Operating cost refers to the cost to run an established plant and produce oil. Facilities that opt to upgrade bitumen into a light synthetic crude oil (SCO) will incur additional development/capital cost and operating cost than those that do not upgrade. In exchange, they sell a higher-quality and thus higher-priced crude oil. Facilities that opt to dilute bitumen with lighter hydrocarbons to permit pipeline transport will incur additional cost associated with the acquisition of the diluent. The cost of diluent is not typically reported as part of a producer's operating cost because it also has value, although generally the value received for diluent by oil sands companies from end-use refiners is less than the acquisition cost.

Capital costs have continued to fall

Since 2014, the cost to construct a new oil sands project has come down. IHS Markit tracks the cost of the individual components that underpin the construction cost of an oil sands facility—capturing the pure inflationary or deflationary changes in oil sands construction cost over time (i.e., the change in cost to construct the same operation over time). From 2014 to 2018, IHS Markit estimates that the oil sands capital cost deflated, on average, by 10%. While this result may not seem significant, considering the scale of oil sands projects—which can average more than $1 billion—it represents a savings of at least $100 million. See Figure 2 for a complete history of oil sands capital cost inflation/deflation.

Figure 2

Oil sands capital cost index (inflation)



Source: IHS Markit © 2019 IHS Markit

However, no one would build the same project today that would have been built in 2014. Over the past four years, producers and service providers have been working to reengineer and redesign operations. They have focused on simplifying project designs, building for less, constructing more quickly, and ramping up production faster. In addition to the cost deflation shown in Figure 2, recent announcements by oil sands producers indicate that reengineering may have resulted in an additional savings of 20–25% for new SAGD projects (the dominant source of growth in the IHS Markit outlook). Taken together—reengineering and cost deflation—the cost of a new oil sands project may be anywhere from 25% to a full third cheaper than in 2014.[1]

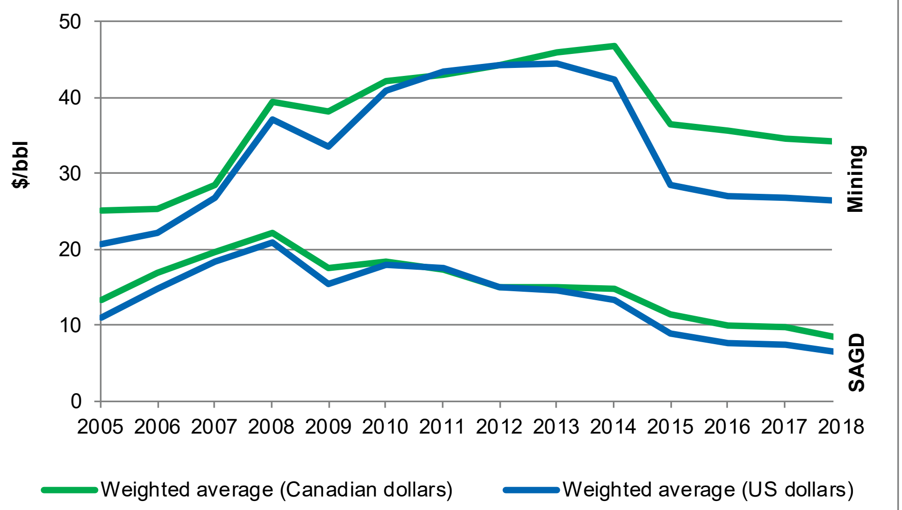
Operating costs have nearly been cut in half

Operating costs fell more dramatically than capital cost (see Figure 3). From 2014 to 2018, the operating cost for both oil sands mining operations with an upgrader and SAGD facilities fell, on average, by more than 40%. In some instances, operators were able to cut operating costs in half. In 2014, the average SAGD operating cost ranged in the mid- to high teens per barrel, whereas in 2018 it had fallen to less than $10/bbl. Some operations are achieving an operating cost approaching $5/bbl. Integrated mining operating costs averaged above $40/bbl in 2014 compared with under $30/bbl in 2018.

1. In 2014, IHS Markit assessed the typical oil sands SAGD project capital cost to be approximately $40,000–50,000 per flowing barrel, with expansions being approximately $10,000 per flowing barrel lower. Recent announcements by various operators indicate a potential capital cost range of $28,000–38,000, with expansions potentially ranging around $20,000 per flowing barrel of capacity.

Figure 3

Canadian oil sands operating cost, 2005–18



Source: IHS Markit

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The key drivers behind the operating cost reductions include access to more efficient labor and capital, finding ways to do more with less, and improvements in operational efficiency and project reliability. Slowing activity has allowed producers to access more efficient or productive labor and equipment. Project operators have also sought to weed out unnecessary expenses. For example, mines that used to run multiple garbage trucks may now run only one. What once was thought important, such as an exterior light here or there at a plant, may now be deemed unnecessary. However, the largest factor appears to be a focus on reducing facility downtime and increasing throughput—in other words, increasing reliability. Oil sands operating costs have a high fixed cost component. Improvements in reliability allow more units to be produced (greater output), which lowers the cost on a per unit basis. These improvements also have positive implications for the greenhouse gas (GHG) emission intensity, which has fallen 10% since 2014.[2]

The resilience of cost reductions

Looking at key measures of cost deflation—operating and capital cost, shown in Figures 2 and 3—it is apparent deflation may be in the trough. This situation raises questions about the potential for further reductions or how resilient current savings may be. This subsection discusses the outlook for oil sands cost.

Although Figures 2 and 3 point to slowing cost reductions, with overall western Canadian upstream activity trapped by both government production limits and available transportation capacity, a rapid rise in inflation is unlikely in the immediate term. Looking beyond current constraints, there are inflationary risks to the oil sands cost structure. These risks include the capacity of the remaining western Canadian service sector, which has contracted since 2014, as well as the potential for increased competition for services and skilled labor from emerging western Canadian unconventional plays, associated petrochemical and midstream infrastructure build-out, and advancing west coast LNG export projects.

However, it is important to make a distinction between inflation- or deflation-driven cost changes—increases or decreases in the cost of key inputs—versus changes that are the result of structural changes, such as how projects are designed, constructed, and operated. Structural changes tend to be more permanent.

IHS Markit analysis indicates that the largest share of oil sands capital cost reductions can be attributed to structural changes. For example, of the capital cost reductions we have tracked for SAGD, we estimate two-thirds to three-quarters of savings may be associated with reengineering and design changes. This result may mean oil sands costs have greater potential to remain in check even should inflationary pressures resume. There are also new technologies being piloted that have the potential to deliver even greater capital savings.

2. For more information on oil sands GHG intensity, see the IHS Markit Strategic Report *Greenhouse gas intensity of oil sands production: Today and in the future*.

See the text box “The promise of technology: Potential future capital efficiency gains” for a discussion of potential implications of advancing steam displacement technologies.

The promise of technology: Potential future capital efficiency gains

Producers are advancing various forms of “steam displacement technologies” as a means to drive operating and capital costs lower (as well as GHG emission intensity). Solvent-assisted extraction is the most talked about, but producers are actively experimenting with the coinjection of methane and other noncondensable gases.

SAGD operates on two fundamental principles: the transfer of heat from steam to the bitumen to improve its mobility and pressure from the application of steam to drive the mobilized bitumen to the recovery wells (assisting gravity). Producers have learned from experience that the reservoir can hold temperature better than they earlier anticipated. This fact means they may be able to reduce the energy required over time. The challenge is that they need to maintain pressure. They are experimenting with injecting noncondensable gases, like methane, that can physically replace some of the steam required per barrel. SAGD facilities are sized to manage treatment of recovered water and the generation of steam. As the steam needed per barrel falls, producers can redeploy excess steam and produce more oil from the same capital investment—increasing capital efficiency and potentially reducing operating cost depending on the cost and recycle rate of the coinjected material.

The price of oil required to break even is down

In part because of cost improvements, the price of oil required for a new oil sands project to cover and earn a return on investment capital has fallen. The oil price breakeven is an important metric that determines the relative attractiveness in investing in a new oil-producing asset. For our analysis, we include all the up-front capital required to bring an oil project online, the cost to operate the facility over its life, any sustaining capital required to maintain the operation, and a reasonable return on capital deployed (we used 10% for this analysis), discounted back to the present. Because oil sands operations produce both heavy and light crude, the breakevens are expressed on a WTI equivalent basis (adjusting for quality and transportation costs to allow for an apples-to-apples comparison).

All things being equal, the price of oil required to justify a new oil sands project—mining or SAGD—has fallen. As shown in Figure 4, IHS Markit estimated that the lowest-cost oil sands project—an expansion of an existing SAGD facility—required a WTI price more than $65/bbl in 2014 to break even. In 2018, this price had fallen into the mid-$40s/bbl. A mine without an upgrader required a WTI price approaching $100/bbl in 2014 compared with nearly $65/bbl in 2018.[3]

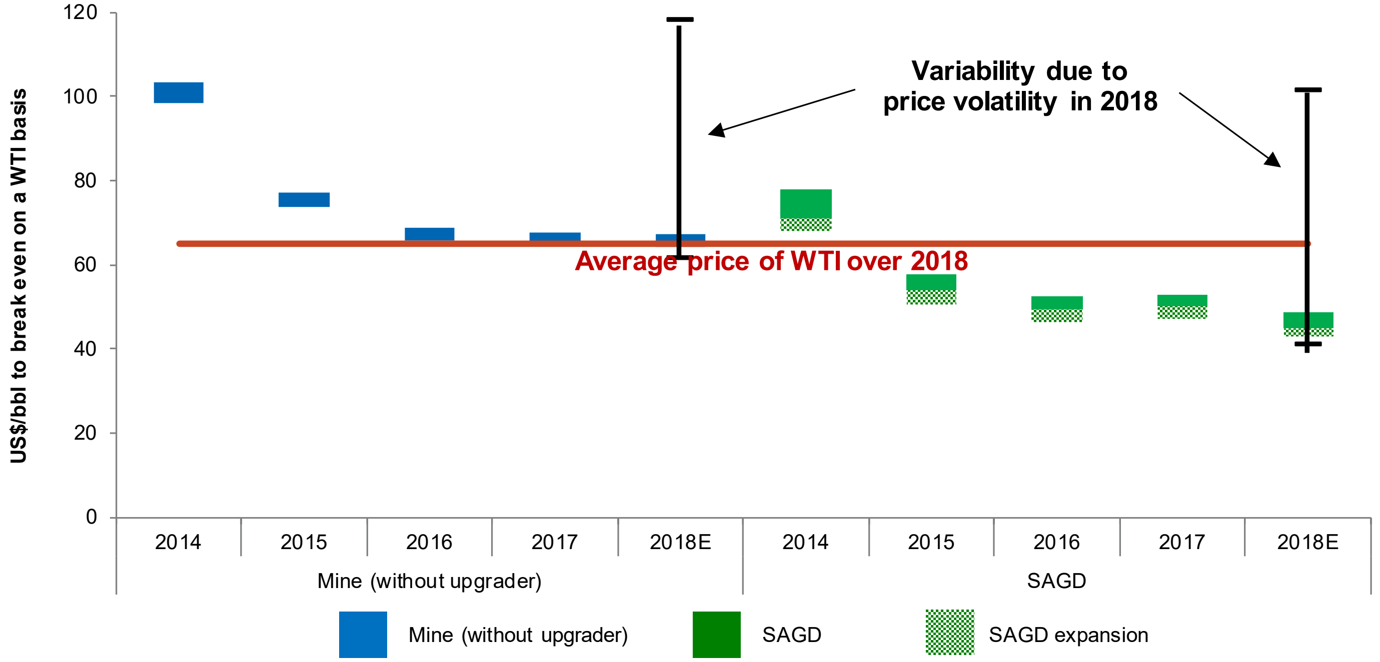
Local, not global, prices holding back oil sands

Despite the sizable reductions in operating cost and capital cost, oil sands economics hinge on a number of market-based factors. These factors can be as important as, if not more important than, factors arguably within the producer’s control (such as operating and capital cost). These include factors like the price of natural gas used to generate heat and steam; the price of condensate used in the creation of diluted bitumen (for facilities that lack an upgrader); exchange rates that influence the cost of goods purchased in Canadian dollars while oil is sold in US dollars; and finally (and perhaps most importantly), the basis differential or difference in price between crude oil in western Canada and crude priced in the US and international markets.

3. It is important to note that these break-even estimates assume a differential between western Canada and WTI more consistent with that in 2017 (and early 2019), approximately $12/bbl between western Canadian heavy oil as tracked by Western Canadian Select (WCS) and WTI, as opposed to the extreme volatility in 2018.

Figure 4

Canadian oil sands break-even analysis, 2014–18



Source: IHS Markit

These market-based inputs are not necessarily always negative for the Canadian oil industry. Canada is a major exporter of crude oil, and during the low oil prices of the past few years, the rapid reduction in the value of oil exports contributed to a weakening in the value of the Canadian dollar. This reduction, in turn, lowered the price of goods that producers sourced domestically. Therefore, although producers were receiving a lower price for their oil, the lower cost of goods helped offset some of this impact. Additionally, the price of natural gas—an important input cost for oil sands producers—has fallen since 2014. From 2014 to 2018, the price of natural gas in western Canada has fallen more than two-thirds, from $4.00/Mcf in 2014 to about $1.20/Mcf in 2018. Additionally, the expectation is that western Canadian gas prices will likely remain beneath $3.00/Mcf for the foreseeable future. The price of condensate in western Canada typically commands a premium to light crude oil, but also tracks global benchmarks, and its value declined along with crude oil over the past few years, another benefit on the cost side for oil sands producers.

To a large extent, these market variables worked in the oil sands' favor through the worst of the low oil prices over the past few years. However, the impact of oil price differentials is a different story. A differential is the price difference of a particular crude oil relative to the price of oil in another region or globally, as typically tracked by key oil benchmarks such as WTI or Brent.

A differential typically consists of both a quality factor, which accounts for the differences in properties of various crude oil, and a transportation factor, which captures the cost to move a crude oil between markets. For an inland producer of crude oil, the narrower the differential, the lower the difference in price between regions would be, and the better it is for the producer. In western Canada, if the market is functioning smoothly and producers can move their crude to US markets via pipeline, western Canadian heavy crude oil should trend toward $14–16 beneath WTI on average—reflecting the approximate transportation and quality difference to Cushing, Oklahoma, where WTI is traded.

Through the oil price downturn from 2014 to 2017, differentials seemed to work in the producer's favor. In fact, in 2017, western Canadian heavy oil averaged $12/bbl beneath WTI—a stronger level than what would otherwise be expected.[4] However, in 2018, western Canadian supply began exceeding available pipeline capacity, forcing some producers to seek alternative means to market, most notably crude-by-rail. Canadian oil exports by rail more than doubled over 2018, from 144,000 b/d in January to 354,000 b/d in December.[5] Despite this rapid expansion, movements still lagged demand. Some producers faced the prospect of not being able to move their product to market and were forced to discount their barrels by increasingly larger amounts, which led to a widening of the differential. In 2018, the western Canadian heavy oil differential, as tracked by WCS, averaged $27/bbl below WTI—more than double that in 2017. Moreover, over the course of the year, the differential ranged wildly from $11/bbl to more than $50/bbl beneath WTI—the worst level in recorded history.

The impact of the volatility in the western Canadian differentials transferred to the price of oil in western Canada—above and beyond global price volatility. At its worst, the price of western Canadian heavy oil reached lows of $14/bbl around mid-November. This result was lower than that in early 2016 during the nadir of the global oil price collapse.

Because differentials impact the price of oil received by producers in western Canada, they have a direct and pronounced impact on oil sands economics. Generally, the wider the differential, the lower the price of oil in western Canada relative to global benchmarks and thus the higher the break-even price will be required to offset the differential. When differentials were at their narrowest in 2018—about $11/bbl beneath WTI—we estimate that a new greenfield SAGD project would require a WTI price in the low $40s/bbl (and expansion of an existing facility being even lower) to break even. At the worst or widest differential in 2018, the differential exceeded $50/bbl. If sustained, the implied breakeven would have ballooned to nearly $100/bbl. For unintegrated mines, the breakeven ranged from $60/bbl to $120/bbl, WTI.

The extreme price volatility in late 2018 resulted in the Government of Alberta intervening in the market to reduce the extraordinary price differentials by mandating a cap on oil production in 2019. This action, coupled with a tightening of available heavy oil globally, principally from further deterioration of Venezuelan production, has contributed to narrower than historical light-heavy spreads and thus attractiveness of oil sands project economics. Over the first quarter of 2019, the differentials averaged about $12/bbl between WCS and WTI. However, it is expected that as Alberta eases production limits, known as curtailment, over 2019, the differentials should increase to reflect the higher cost of crude-by-rail. The decision by the government may have bought the industry time to bring in additional rail capacity to prevent a recurrence of the extreme volatility seen in 2018. However, the uncertainty of unresolved pipeline issues and potential for price volatility is contributing to price insecurity in western Canada in the immediate term.

An uncertain investment climate

Investments in the Canadian oil sands are generally based on the long-term potential returns that accrue from projects that can produce oil for multiple decades—a time horizon that is unique in the world of oil production. However, investments in the Canadian oil sands are not immune to investor confidence, which tends to take a much shorter view.

Ongoing campaigns against the expansion of the Canadian oil sands have contributed to multiple delays in the timing of new pipeline takeaway capacity, which ultimately contributed to the extreme price volatility of 2018.

4. For more information on why this premium occurred, see the IHS Markit Strategic Report *Looking north: A US perspective on Canadian heavy oil*.

5. Source: National Energy Board, "Canadian Crude Oil Exports by Rail – Monthly Data," https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/cndncrdlxprtsrl-eng.html, accessed 24 February 2019.

Investors are now questioning Canada's ability to complete the necessary pipeline infrastructure projects and thus the potential value of western Canadian crude.

Out of a fleet of five originally proposed pipeline projects, three remain in the race (see Table 1), with the average length of time in review now exceeding three-quarters of a decade. The Line 3 Replacement project is currently the most advanced and could be online in the second half of 2020. This project is followed by the Keystone XL and Trans Mountain pipeline projects, which could stream in late 2021 and 2022, respectively—although Keystone XL is increasingly looking like it may not be online until 2022 as well. IHS Markit estimates that Line 3 will be insufficient on its own to absorb the existing production potential in western Canada and that additional capacity is required. In the interim, IHS Markit believes crude-by-rail will be a critical component of the western Canadian transportation mix, with a structural element remaining in place over the long term.

Historically, industry hesitated in investing in additional rail capacity based on the anticipated timing of future pipelines that in the end have continued to be delayed. In the end, however, supply ended up overtaking available takeaway capacity in 2018. This result encouraged a more rapid expansion of crude-by-rail. It is hoped that the Alberta government's action to curtail production will provide time for additional capacity—both pipe and rail—to be brought online to prevent a future shortfall in takeaway capacity.

A more modest oil sands growth scenario emerging

Despite remarkable cost reductions outlined in this report, the western Canadian oil market continues to move through a period of price uncertainty. This period of uncertainty was first brought on by the shift to lower global oil prices that began in 2014 but is now largely dominated by regional price disparities stemming from significant delays to the timing of advancing pipeline projects. To add complexity, there are yet more challenges on the horizon for the industry, including the pending international low-sulfur marine fuel specification coming into force in 2020, which could once again weaken heavy crude prices relative to light crudes.[6] These challenges—particularly around the value of western Canadian heavy oil—are expected to continue to contribute to hesitation over future large-scale investment decisions in the Canadian oil sands until some of the uncertainty can be resolved.

Looking out over a longer horizon, IHS Markit believes growth will continue in the Canadian oil sands—albeit at a much slower pace. During 2009–18, oil sands grew at an annual average rate of approximately 160,000 b/d. Over the coming decade (and a bit), from 2018 to 2030, IHS Markit expects oil sands additions to average

Table 1

Major long-distance Canadian crude oil export pipeline projects

Destination	Pipeline project (proponent)	Route	Incremental capacity (b/d)	Review initiated	Status
US markets	Line-3 Replacement (Enbridge)	Edmonton, Alberta, to Superior, Wisconsin	About 380,000	2012	Permitting
	Keystone XL (TransCanada)	Hardisty, Alberta, to US Gulf Coast region	830,000	2008	In review
Eastern Canada and East Coast offshore	Energy East (TransCanada)	Hardisty, Alberta, to tidewater in Saint John, New Brunswick	1.1 million	2014	Canceled
West Coast offshore	Northern Gateway (Enbridge)	Bruderheim, Alberta, to Kitimat, British Columbia	525,000	2010	Denied
	Trans Mountain Expansion (Government of Canada)	Edmonton, Alberta, to tidewater in Burnaby, British Columbia	590,000	2013	In review

Source: Various sources, IHS Markit

6. For more information on the low-sulfur marine fuel specification, see https://ihsmarkit.com/research-analysis/navigating-choppy-waters-initial-findings.html and https://ihsmarkit.com/Info/0818/navigating-choppy-waters.html.

beneath 100,000 b/d per year. Although more modest than the past decade, the anticipated growth should still be sufficient to allow oil sands production to top 4 MMb/d by 2030—1 MMb/d more than in 2018. This level of growth may seem significant, but a lot of supply can come simply through optimization and ramp-up of existing or recently completed facilities. In fact, nearly one-third of growth in the IHS Markit outlook to 2030 comes from ramp up, optimization, and then sustaining of existing facilities. Key to the scale of future growth will be the ability of government and industry to restore confidence that Canadian crude oil will get to market by pipe or rail.

IHS Markit Customer Care

CustomerCare@ihsmarkit.com
Americas: +1 800 IHS CARE (+1 800 447 2273)
Europe, Middle East, and Africa: +44 (0) 1344 328 300
Asia and the Pacific Rim: +604 291 3600

IHS Markit®