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# Oil Sands Cost and Competitiveness

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**STRATEGIC REPORT**

Canadian Oil Sands Dialogue | Special Report


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# Oil Sands Cost and Competitiveness

## Key implications

Over the past 15 years, the Canadian oil sands has been a pillar of global supply growth. Yet growth did not occur without challenges. One of these challenges was rising development costs. The 2014–15 oil price collapse poses a fresh challenge for continued growth in the Canadian oil sands. This report looks back at historical costs and assesses what these trends and a changing business environment mean for the competitiveness of oil sands investment.

- **As output grew, the cost to construct new projects appreciated—indeed, cost challenges were partly a product of the industry's success—rising over 70% from 2000 to 2014.** In the early 2000s, oil sands projects were truly greenfield. Many projects were first-of-a-kind, access to labor and services was limited, and the oil sands region lacked sufficient infrastructure such as roads and power lines, which pushed up development costs.

- **Regional competition for skilled labor was a key factor behind historical capital cost escalation.** Labor cost—a function of wage and productivity—is the single largest input to construct an oil sands facility and also influences the cost of other key regional inputs. Stiff competition for workers—a product of the scale of labor demands—helped drive labor costs higher, contributing to overall project cost escalation.

- **Nonetheless, even prior to the 2014–15 price collapse, cost pressures appeared to be moderating owing to both local and international factors.** Major input cost pressures subsided in recent years. Fabrication yard capacity expanded, global steel prices softened, and oil sands companies realized the need to better manage cost pressures.

- **Lower oil prices are poised to reset costs globally, and the oil sands competitive position may shift.** Prior to the price collapse, oil sands projects were competitive with other growth opportunities around the world in the mid to high range of the cost spectrum. Oil sands costs are declining, but it is unclear how the oil sands—along with other large capital projects—will fare in terms of costs and margins in a post–price collapse world.

- **The oil sands of tomorrow will be different from the past, which may provide an opportunity to keep future cost pressures in check.** The investment ecosystem has benefited from the expansion of the regional infrastructure, the service sector, and the labor market since the early 2000s. Lower oil prices are lowering investment but also lowering capital and operating costs. Small-scale brownfield expansions—which require less labor, investment, time, and capital—will drive future growth.

—December 2015

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# Oil Sands Cost and Competitiveness

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## About this report

**Purpose.** Over the past 15 years, costs in the Canadian oil sands rose steadily. This was not isolated to the oil sands; oil production costs increased around the world. Yet, cost escalation in the oil sands was considered particularly acute. In the run-up to the 2014 oil price collapse, questions were being raised about the industry's long-term competitiveness in light of this historical trend. This report looks back at historical costs in the oil sands and assesses what these trends and a changing business environment mean for the competitiveness of oil sands investment in the future.

**Context.** This report is part of a series of reports from the IHS Canadian Oil Sands Energy Dialogue. The Dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Participants include representatives from governments, regulators, the oil and gas industry, academics, pipeline operators, refiners, and nongovernmental organizations. This report and past Oil Sands Dialogue reports can be downloaded at www.ihs.com/oilsandsdialogue.

**Methodology.** IHS conducted its own extensive research and analysis on this topic, both independently and in consultation with stakeholders. This report was informed by a multistakeholder survey; a workshop held in Calgary, Alberta, on 23 October 2014; and participant feedback on a draft version of the report. IHS has full editorial control over this report and is solely responsible for the report's content (see the end of the report for a list of participants and the IHS team).

**Structure.** This report has five parts and an appendix:

- Introduction: Growth, costs, and the future
- The unconventional oil sands
- Understanding oil sands costs: History and current environment
- Oil sands competitiveness
- Conclusion: Toward a globally competitive industry
- Appendix: Oil sands' history of capital cost escalation in detail

1. With special thanks to Carmen Velasquez, former Director at IHS Energy and currently Executive Director for Energy Programs at the University of Alberta School of Business.

## Introduction: Growth, costs, and the future

From 2000 to 2014, Canadian oil sands production more than tripled, from about 600,000 b/d to over 2.2 MMb/d. As investment increased, costs escalated—sometimes dramatically. Indeed, this issue was not isolated to the oil sands or Canada. The cost of new projects rose globally over most of this period. But for the oil sands, rising costs had a pronounced impact on the price tag of new projects. IHS estimates that from 2000 to 2014 the cost for new projects increased over 70%. That means a project that cost $2.5 billion in 2000 would cost over $4.2 billion in 2014.[2]

At the same time, western Canadian producers suffered from constrained pipeline takeaway capacity that, at times, reduced the price that producers were able to obtain for their oil. In the run-up to the 2014 price collapse, concern about escalating costs was raising questions about the viability of future projects and oil sands' ability to compete with new supply sources globally.

A much lower oil price environment poses a fresh challenge for Canadian oil sands growth. Planned capital expenditures in new projects have been cut and cut again. However, projects under construction prior to the price collapse are expected to come online and ensure that oil sands output will rise through the end of the decade—up from about 2.3 MMb/d in 2015 to over 3 MMb/d by 2020.

Yet, as these projects under construction are completed, construction activity is slowing, and cost pressures are easing. Globally, oil field development costs are poised to reset at a lower level. Shifting global cost structures could have an impact on the relative competitive position of oil sands. Moreover, the prospects of changes to fiscal terms and more stringent carbon policies have moved up the list of challenges that could affect industry competitiveness. Will the oil sands industry be able to achieve similar cost reductions as their global peers? Will oil sands' history of cost appreciation return with higher oil prices? And what will the impact be on oil sands competitiveness and future growth?

This report explores oil sands costs and competitiveness—past, present, and future. It includes a review of oil sands economics, history of capital cost escalation, and how the industry may be at a turning point in future cost escalation. The report concludes with a discussion about how lower prices may shift the oil sands, relative competitive position in the world.

There are five sections and an appendix.

- Introduction: Growth, costs, and the future
- The unconventional Canadian oil sands
- Understanding oil sands costs: History and current events
- Oil sands competitiveness
- Conclusion: Toward a globally competitive industry
- Appendix: Oil sands' history of capital costs escalation in detail

This report focuses primarily on the cost of new oil sands projects. There are multiple methods of oil sands production, including in-situ steam-assisted gravity drainage (SAGD), cyclic steam stimulation (CSS), primary or cold flow, and mines with and without upgrading. Some of these methods are discussed in the box "Canadian oil sands primer," along with relevant oil sands background and definitions. SAGD and mines with upgraders are the dominant sources of current production, but SAGD and mines without upgraders represent the majority of greenfield developments today. For this report, our analysis focuses on the cost of SAGD and mines without an upgrader, with some discussion of mines with upgraders.

2. Unless otherwise stated, all values are in US dollars.

## Canadian oil sands primer

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

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

**Bitumen blends.** To meet pipeline requirements, bitumen is diluted with lighter hydrocarbons (often natural gas condensates) into a bitumen blend. A common bitumen blend is dilbit—short for diluted bitumen—typically about 70% bitumen and 30% lighter hydrocarbons. We expect the vast majority of oil sands supply growth in the future to be bitumen blends.

**Synthetic crude oil (SCO).** SCO is produced from bitumen via refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions from which gasoline and diesel are manufactured. These units are called upgraders. SCO resembles light, sweet crude oil. We do not expect meaningful growth in SCO supply in the future because of challenging economics.*

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

**Mining.** About 20% of currently recoverable oil sands reserves are close enough to the surface to be mined. In a surface mining process similar to coal mining, the overburden (vegetation, soil, clay, and gravel) is removed and stockpiled for later use in reclamation. The layer of oil sands ore is excavated using massive shovels that scoop the material, which is then transported by truck to a processing facility. About 45% of today's production is from mining. Mines can come with and without upgrading units.

- **Integrated mines.** The original mining operations all featured an integrated upgrader that transported bitumen into higher quality SCO.
- **Unintegrated mines.** The two most recent mining operations (one recently completed and another under construction) do not include an upgrader and will, instead, market a bitumen blend.

**In-situ thermal processes.** About 80% of the recoverable oil sands deposits are too deep to be mined and are recovered by drilling. Thermal methods inject steam into the reservoir to warm and lower the viscosity of the bitumen and allow it to flow to the surface. Similar methods are used in oil fields around the world to recover oil. Thermal processes make up 45% of current oil sands production, and two commercial processes are used today:

- **SAGD.** SAGD is the fastest growing method; it is projected to grow from 34% of production in 2015 to 43% of oil sands production by 2025.
- **CSS.** CSS was the first process used to commercially recover oil sands in situ. CSS currently makes up about 11% of production and is projected to account for less than 8% of total production in 2025.
- **Primary production.** The remaining oil sands production is referred to as primary production. Less viscous, it is extracted without steam using conventional oil production methods. Primary production currently makes up nearly 11% and is projected to be less than 8% by 2025.

For more information on upgrading economics, see the IHS Energy Special Report *Extracting Economic Value from the Canadian Oil Sands: Upgrading and refining in Alberta (or not)?*

# The unconventional Canadian oil sands

## Oil economics 101

Oil production makes money on the difference between the market value of the oil produced and the cost to extract and transport it to market. The decision to invest in new oil production is based on both the anticipated oil price and the cost to produce it (both the operating and capital costs, which together represent most of the full cost of production). Additional elements that have an impact on investment decisions—apart from price and cost—include political risks, such as actual or potential changes to fiscal or regulatory regimes, and security concerns.

The most important determinant behind the cost to produce oil is the reservoir—where oil is found and how much is there. This includes whether operations are located onshore or offshore and if they are in extreme climates or remote areas, what extraction method will be employed such as whether conventional or unconventional techniques or processes are needed.

The reservoir location also influences the project risk—that is, the likelihood that the outcome will not turn out as anticipated. This includes the degree of political stability and physical security. The greater the potential instability, the faster a project may be required to be profitable to offset the risk. Together these are the broad features that underpin project economics.

## The unique attributes of the Canadian oil sands

The Canadian oil sands are unique. In most of the world, oil is found in large reservoirs within the pores and cracks of rocks deep underground. Oil is produced from these formations by drilling down into them. The greater the cracks or permeability, the more easily oil can be recovered. Over time, advancements in drilling and other technologies have enabled access to increasingly complex reservoirs.

The oil found in the oil sands is not trapped within large rocks but within a mixture of sands, clays, and water. After millions of years, the lighter hydrocarbons have escaped or decayed, leaving the larger, longer hydrocarbon chains, which results in a heavy, more viscous crude oil.

Production from the oil sands is unconventional. Extraction is done either by digging up the oil sands ore in surface-top mining operations or in situ, which makes use of more conventional drilling techniques coupled with the injection of steam into the ground to warm and mobilize the bitumen to permit recovery.

Oil sands crude oil itself is also unconventional. Known as bitumen, in its raw state it is semisolid at ambient temperature. To permit bitumen to be piped to market, it is either blended with light oil to produce a lighter bitumen blend or converted into a light SCO.

## It takes scale and large capital investments to overcome oil sands production challenges

Large upfront capital investments in processing equipment and facilities are required to overcome oil sands production challenges. For example, the sand in the oil sands is particularly abrasive, requiring highly durable parts and equipment. The climate in northern Alberta also varies widely from summer to winter. Equipment and infrastructure must be capable of withstanding a temperature variance of over 130 degrees Fahrenheit between seasons, from above 90 degrees Fahrenheit (30 degrees Celsius) in the summer to below minus 40 degrees Fahrenheit (minus 40 degrees Celsius) in the winter.

Projects are scaled up, increasing total construction costs but spreading costs over a larger volume of production to capture economies of scale. This is particularly true for mining operations, which have typically been built in phases in excess of 100,000 b/d—a project scale individually equivalent to about 5% of oil sands production in 2014.[3] In-situ projects

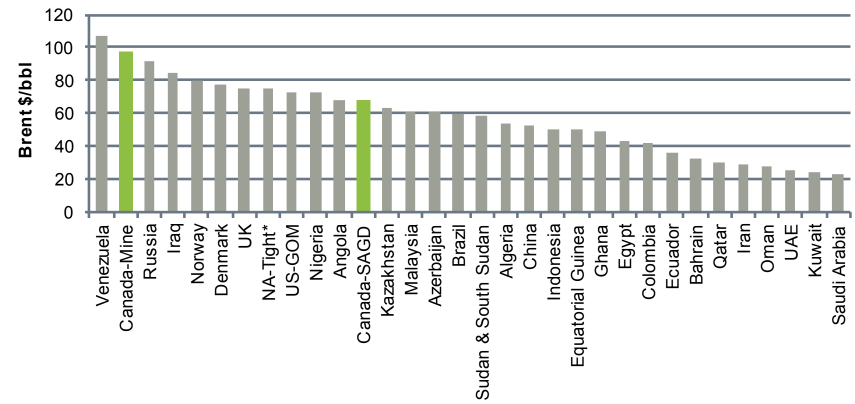
3. The two most recent oil sands mining projects to come online, Phase 1 of Imperial Oil's Kearl project and Phase 1 of Canadian Natural Resources' Horizon project, were initially scaled at 110,000 b/d and 135,000 b/d, respectively.

are typically smaller, historically about 30,000 b/d, but commercial projects have ranged from 5,000 b/d to over 100,000 b/d.[4]

Overcoming oil sands production challenges requires very high levels of investment capital. Most oil sands investments range from $1 billion to $10 billion and take between two to five years to come online once a decision to proceed has been made. But despite the capital required, costs per barrel of production are comparable to many other supply sources in the mid to high range of the cost spectrum (see Figure 1). Once operational, with periodic capital investments, oil sands facilities can produce a steady volume of crude oil for over 30 to 40 years. This long-lasting level of output is different from that of the vast majority of the world's oil fields, which enter into decline after reaching a peak in production. These features compare favorably to other resources that may be lower cost to develop but have greater exploration risk (insufficient oil is found to make production commercially viable) or are located in less politically stable or secure regions, which could cause operational and financial difficulties.

Figure 1

**Average 2014 Brent break-even price full-cycle 10% discount rate by selected nations/supply: Ranked highest to lowest break even with high and low price range for new projects**




Notes: Oil sands growth is dominated by two distinct types of production, mining and SAGD. Mining break even equates to an unintegrated facility without an upgrader that markets diluted bitumen. Break-even price shown in this figure is from 2014 and should be considered as preprice collapse.
Source: IHS Energy



## The Canadian oil sands is not "easy oil"

Over the past 15 years, the Canadian oil sands featured prominently among an array of global opportunities for upstream investors. The attractive characteristics of oil sands production outweighed the negative aspects.

Despite attractive features, the oil sands resource is not "easy oil." Both a remote and challenging climate and geology pose significant development and production challenges. Overcoming these challenges requires large-scale capital investments, as outlined above. As investment in the oil sands grew, other types of challenges emerged—environmental opposition, infrastructure limitations, and cost escalation. This report focuses on oil sands costs and competitiveness. Prior reports in the IHS Oil Sands Dialogue have explored other key challenges.[5]

# Understanding oil sands costs: History and current environment

The cost of an oil sands project includes both the upfront capital cost to design, construct, and start up operations and the cost to operate and maintain production. In this section we look at the history of escalating costs in the oil sands, consider recent upfront capital costs, and then examine the day-to-day cash costs required to operate a facility. At the end of the section, we discuss at which oil prices oil sands facilities break even.

## History and current environment of oil sands upfront capital costs

High—and often rising—upfront capital costs have been a perennial challenge for oil sands investors. There are numerous examples of the final price for a project being significantly higher than the original estimate. From 2000 to the end of 2014, IHS estimates that the upfront capital cost of a SAGD project and mine project increased approximately 70%

4. Pilots or demonstration projects are not included in these estimates.

5. See the recent IHS Energy Special Report *Why the Oil Sands? How a remote, complex resource became a pillar of global supply growth* available at www.ihs.com/oilsandsdialogue.

and 80%, respectively. This means that a project that cost $2.5 billion in 2000 would cost $4.25 billion to $4.5 billion in 2014. This section explores the history and current environment of oil sands capital costs.

### Labor, the largest share of upfront capital costs and largest source of cost increases

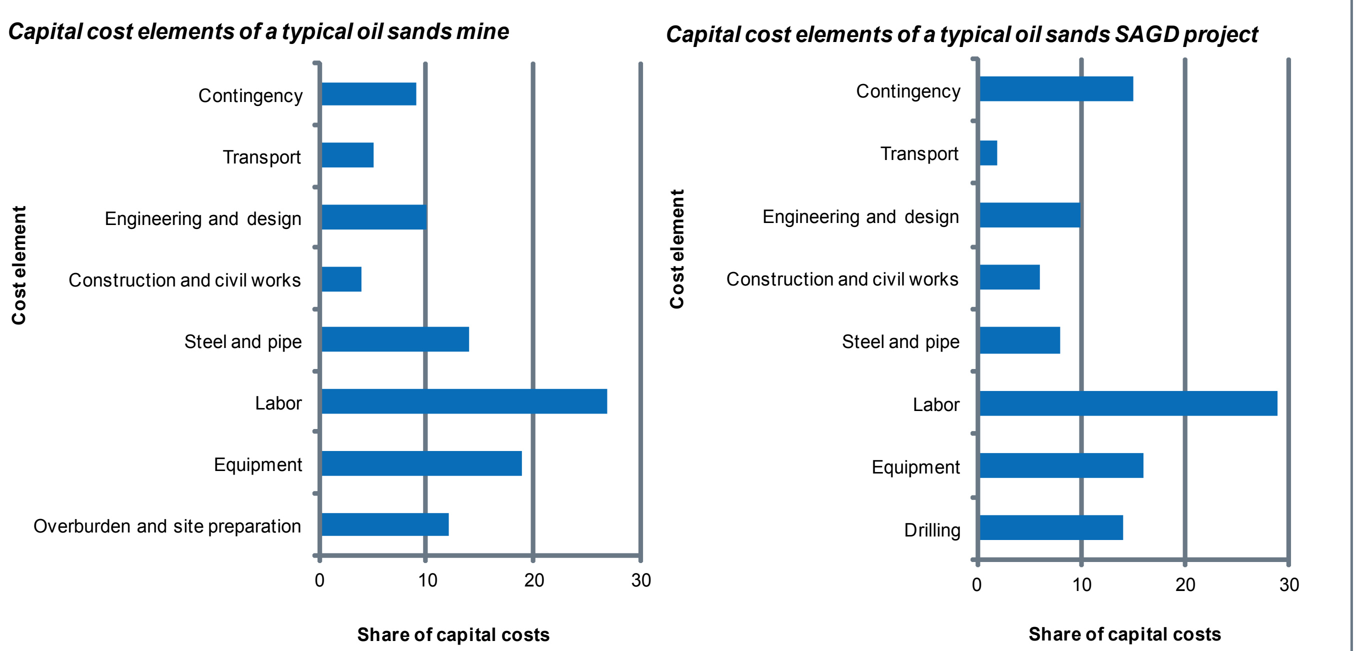
Growth in the Canadian oil sands started to accelerate after 2000, when an increase in global oil prices and the successful deployment of SAGD technology led to a material increase in investment and activity. Mining activity also grew as existing facilities were expanded and several new operations were built. In real terms, capital investment over the past 15 years, from 2000 to 2014, was over five times greater than total capital investment from 1958 to 2000—$200 billion compared with $30 billion.[6]

Labor is a key reason for cost differences among regions. Labor costs are a function of both wages and productivity, where productivity is measured by the time required to complete a given task. Alberta's climate is a concern, with cold weather reducing worker productivity. Alberta is also landlocked, keeping on-site labor requirements higher than for regions that have access to tidewater and can import large modularized components from offshore suppliers.

Construction costs for a greenfield project include many elements, but labor is the largest part, accounting for about 30% of total cost (see Figure 2). Other major cost inputs include engineering, design, and project management; cost to purchase equipment, steel, and pipe; and the cost to physically construct the facilities and to transport goods and workers to the site. SAGD has the additional cost to drill and complete steam injection and recovery wells. Mines require more extensive site clearing, involving the removal and storage of vegetation and top soil, as well as the preparation of mine pits. Both types of projects also require contingency funds to cover unforeseen developments.

Figure 2

**Capital cost elements of typical oil sands facilities, 2015**




Notes: The breakdown is the IHS estimate of a typical unintegrated mine without an upgrader and SAGD project. It is based on the IHS oil sands capital costs index, which tracks the cost appreciation of each input over time. This breakdown does not represent any individual project; rather, it is representative of a typical facility.
Source: IHS



6. Canadian Association of Petroleum Producers *Statistical Handbook*.

Since 2000, the cost of globally traded inputs into oil sands projects—such as equipment and steel and pipe—all appreciated, some dramatically. But local factors, such as labor, already relatively more expensive than for many global peers, appreciated as well.

As capital poured into the oil sands and activity increased, the demand for labor and oil field and construction services overtook regional and then provincial capacity and expanded beyond Alberta. This put upward pressure on labor costs. For example, the population of the Municipality of Wood Buffalo (the core oil sands region) more than doubled, from about 52,000 in 2000 to over 116,000 in 2012.[7] Residents of oil sands work camps expanded even more dramatically, from about 6,000 workers in 2000 to over 39,000 by 2012. Moreover, over half of the camp residents did not originate from Alberta, highlighting that labor demands reached beyond the province.

Competition for skilled workers helped push wages up and attracted less experienced workers, lowering productivity. The cost for workers went up, while the length of time it took a worker to complete the same task rose. Rising labor costs also had a knock-on effect on other capital cost elements that relied on the regional labor pool, increasing costs for associated services such as construction, drilling, engineering, site preparation, and overburden removal.

Although labor was the largest factor in escalation of oil sands capital costs over the past 15 years, other factors also helped to drive up costs. We discuss these factors in the appendix, "Oil sands history of capital cost escalation in detail."

### Recent upfront capital cost trends

In 2015, lower oil prices are lowering investment, construction activity, and ultimately costs in the oil sands. However, even prior to the price collapse, there were signs that cost escalation was moderating. Years of investment in building regional infrastructure and in expanding the capacity of the labor market and service sector were helping to moderate cost pressures. Companies have also become more aware of factors that contributed to historical cost escalation, such as labor productivity declines as projects exceed certain scale, and have become more institutionalized in their approach to new projects.

A project's construction costs vary depending on the scale or capacity of the project and the type of extraction (in situ or mining).

To permit comparisons across projects, oil sands capital costs are often expressed as a cost per barrel of production capacity. IHS estimates that at the beginning of 2015, the cost of a typical project ranged from $85,000 to $95,000 for each barrel per day of capacity for a greenfield mine and from $40,000 to $50,000 for each barrel per day of capacity for a greenfield SAGD project (see Table 1).[8] By leveraging existing project infrastructure, such as rights-of-way and cleared land, expansion of existing SAGD facilities can cost as much as $10,000 less for each barrel per day of capacity than a greenfield SAGD facility. Mine expansions generally cannot enjoy the same cost saving. Optimization of an existing mine can increase utilization rates, but meaningful capacity additions will require the construction of a new mine extraction process—known as a mine train. The cost saving of a mining expansion is relatively small compared with the cost of a new mine train.

Table 1

**Typical oil sands project and capital cost at beginning of 2015**

| | Scale | Cost of barrels per day of production capacity (US$) | Total project cost (billion US$) |
|---|---|---|---|
| Mine | 100,000 b/d | $85,000 to $95,000 | 8.5 to 9.5 |
| SAGD (expansion) | 30,000 b/d | $40,000 to $50,000 ($30,000) | 1.2 to 1.5 (1) |

Note: These values are meant to be representative of a typical project and potential range of capital costs for an oil sands unintegrated mine without an upgrader and SAGD project and are not meant represent any specific project.

Source: IHS Energy



Assuming a commercial-scale capacity of 100,000 b/d for a mine and 30,000 b/d for an SAGD facility, the average cost at the beginning of 2015 to construct a greenfield mine and an SAGD project was about $9 billion and $1.4 billion, respectively. SAGD expansion projects (depending on scale) can be about $400 million less than a greenfield SAGD

7. Most recent population estimates place the Municipality of Wood Buffalo population over 125,000. See the Wood Buffalo *Municipal census 2012.*

8. These values are not meant to represent any one specific project. Specific projects may vary from these values. Capital costs are currently falling and may change.

project. These estimates compare with recent greenfield oil sands mining projects that have ranged from $7 billion to $14 billion and in-situ projects of between $500 million and $5 billion (the costs vary by project scale or design capacity).

## Operating costs moved in different directions for different types of projects

The operating costs (also referred to as cash or lifting costs) include the expenses for day-to-day operations of running the facility. If oil prices fall below this line, then the cost to operate the facility is greater than the cash it generates from daily production.[9]

Unlike capital costs, operating costs for oil sands facilities did not rise for all project types (see Figure 3). Costs for mining operations (represented here by integrated mining operations or mines with upgraders) more than doubled, from about $20/bbl in 2005 to over $40/bbl in 2014.[10] In contrast, the operating costs of SAGD facilities managed to stay relatively constant, at between $10 and $20/bbl from 2005 to 2014. SAGD facilities benefited from falling natural gas prices, which account for roughly a third of operating costs; increasing economies of scale from project expansions that occurred over time; and operational improvements that were rolled out, in both existing facilities and newer facilities, incorporating the latest acquired knowledge.[11]

After taking into account transportation and the quality of the different marketed crudes (either SCO or some form of diluted bitumen), IHS estimates that, on average in 2015, an existing SAGD facility requires a WTI basis of between $20 and $35/bbl to cover its cash cost operating costs, and mines with an upgrader need between $30 and $40/bbl.[12]

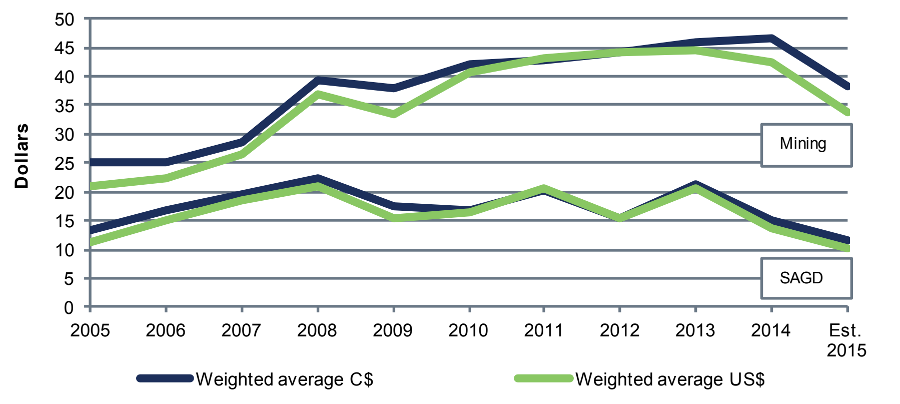
## Oil sands break-even economics

When oil production costs are discussed, it is typically in relation to the full-cycle cost—the total cost to find, develop, and ultimately produce oil. Often this is expressed as the price per barrel of oil required for an investment in new oil production to break even (with a 10% internal rate of return).

Economics of oil sands facilities depend on the design, scale, costs, and market conditions. Break-even points are variable across different projects and as costs decline. IHS used a range to help capture this uncertainty; break-even estimates are based on a high/low range of capital and operating costs and the average market conditions over the first three

Figure 3

**Canadian oil sands operating cost (2005 to 2015)**




Notes: Operating costs are based on the IHS expertise and interpretation of publicly available information. Owing to data availability and development of new facilities, the sample size and weighting from different facilities changed over time. The weighted average for 2015 is based on operating facilities that accounted for about 75% of SAGD production and all operating mines with an upgrader. Pilot operations and facilities in ramp-up were not included. Operating costs shown here are *not* adjusted for transportation or crude quality. Considerable variability in operating cost exists, and operating cost per barrel can be highly variable as it is a function of both the costs and output.

Source: IHS Energy



9. There is no fixed definition of what is captured by operating costs versus sustaining capital. Generally, operating costs include essential costs incurred day to day to maintain production. Sustaining capital is defined here as investment that must be made periodically to maintain production levels (not necessarily day to day). In this report, operating costs and sustaining capital do not include any overhead associated with head office administration, taxes, or royalties.

10. Mine operating costs represent facilities with upgraders and include costs associated with upgrading. One more recent facility is in operation without an upgrader, and another is under construction. These more recent facilities are more relevant in relation to production growth but not to historical operating costs.

11. Natural gas prices in western Canada also fell from over $7/MMBtu in 2005 to $4/MMBtu in 2014. Some examples of improvements include the introduction of wedge wells and greater downhole monitoring. These factors helped offset cost pressures.

12. Range shown is indicative of the operating cost over the first three quarters of 2015. The change in operating costs after adjusting for transportation and quality to WTI basis is less pronounced for mines with upgraders because their product, SCO, historically has priced similarly to or at a slight premium to WTI. This compares with dilbit, marketed from most SAGD facilities, which trades at a discount to WTI.

quarters of 2015. IHS analysis should be considered representative of the average break-even cost in 2015 but not any specific project.[13] Costs are falling in 2015, and the break-even point at the end of 2015 is expected to be lower than at the beginning. The impact of cost reductions over 2015 is discussed at the end of this section.

Figure 4 depicts the break-even economics to construct and operate a new oil sands facility. This includes capital cost, which consists of upfront capital investment, operating cost, sustaining capital, and a 10% return on investment. Sustaining capital includes the replacement costs of key equipment, upgrades, and—for in-situ projects—drilling activity to maintain a supply of bitumen.

IHS estimates that on average in 2015 a new oil sands mine required a WTI price between $85 and $95/bbl to cover all the costs associated with a project with capacity to produce 100,000 b/d of diluted bitumen. An in-situ SAGD project requires between $55 and $65/bbl to produce 30,000 b/d of diluted bitumen. SAGD expansions require prices about $5/bbl less.

Although not officially a cost associated with a particular project, transportation and crude quality have an impact on project economics. The price western Canadian producers obtain for their crude oil is a function of the quality of the crude—the ease with which it is converted into higher-value refined products—and the cost to deliver or transport it to market. To allow easier comparison, the break-even economics were adjusted for transportation to Cushing, Oklahoma, and for quality to WTI, a light benchmark crude oil (see Figure 4).

It is worth noting that it is clear that although prices in 2015 were below the break-even threshold for new projects (explaining why many have been deferred), an existing facility should have, on average, received sufficient revenue to cover its day-to-day operating costs (as shown by the combined wedge of operating cost and transportation and quality adjustments) (see Figure 4).

## Industry at a turning point—Lower prices and less spending are lowering costs

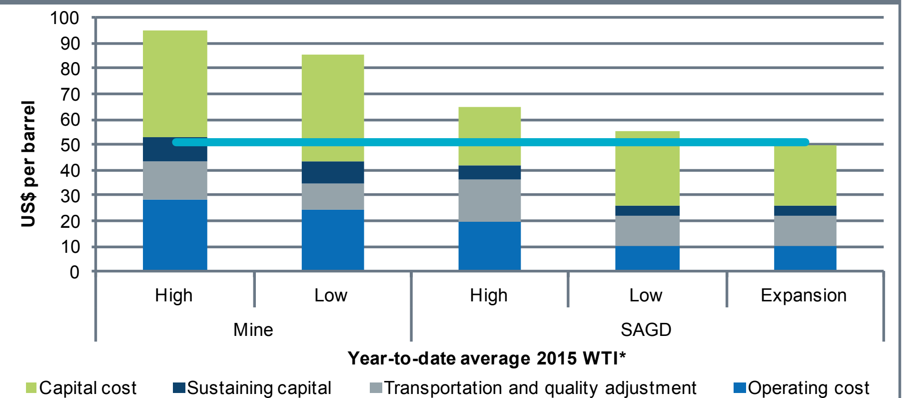
Costs—upfront capital and operating—are dynamic, changing over time and according to market variables. Capital cost increases have been a challenge for oil sands historically, while operating costs have had a more nuanced story. These factors have contributed to the current break-even prices—in the medium to high range of oil investment options.

Even prior to the 2014–15 price collapse, producers were looking to address costs. Efforts are accelerating in the low price environment. Project teams once geared toward developing the next oil sands facility are being redeployed to scrutinize project cost and find opportunities for operating and capital cost reductions.

Capital costs trended down in 2015. As during the 2008–09 downturn, there

Figure 4

**WTI-based break-even price economics of greenfield oil sands projects (estimated average over 2015)**




Notes: Underlying capital costs and operating costs are consistent with a typical greenfield mine without an upgrader, and greenfield SAGD and expansion at the beginning of 2015 (both facilities marketing heavy diluted bitumen blends) using market conditions over the first three quarters of 2015. Underlying capital costs and operating costs are consistent with assumptions presented earlier in this report.
Costs by year-end are expected to be lower; however, the range of assumptions is expected to be consistent with average break-even thresholds over 2015. Additional costs, such as taxes and royalties, are included in the capital cost range but not shown.
Economics of oil sands facilities will depend on the design, scale, project execution, and market conditions. Break-even analysis is based on a typical project and is indicative of the industry at the time of the analysis and is not representative of any one project. Considerable variability between projects exists.
Market volatility—including exchange rates, transportation costs, and diluent prices—in 2015 is influencing the relationship of key oil sands project economic inputs. A number of events also occurred, such as key refinery outages, production outages owing to upsets, and forest fires, which have made 2015 an anomalous year for pricing relationships in western Canada. Uncertainties are captured by showing a range of costs.
*The WTI benchmark price is based on the first nine months of 2015.
Source: IHS Energy


13. Lower prices are leading to cost reduction efforts but are also causing dislocations to a multitude of factors that affect oil sands break-even economics, such as natural gas prices, the exchange rate between Canada and the United States, and the cost of diluent purchased for creation of bitumen blends.

is an opportunity to renegotiate with contractors, gain access to more efficient or productive equipment and labor, and revisit capital investments. There is also less competition for inputs and less pressure on the supply chain. IHS expects the cost to construct a new oil sands production to fall about 6% in 2015 from a year earlier.[14] The Canadian dollar's depreciation against the US dollar, though helpful for producers' revenues, is counteracting some of the benefit of the global slowdown on upfront capital costs by increasing the cost of imports.[15]

Operating costs have also fallen, by about 20% (30% when the exchange rate is factored in), for both mines and SAGD projects in 2015 (see Figure 3). Even lower natural gas prices, greater focus on operational improvement, access to lower service sector rates, and more efficient workers and equipment are all contributing to reductions in 2015. Operators are also maximizing output to spread fixed costs over more units of output. This effectively lowers operating costs reported on a per barrel unit of output.

The net impact of cost reductions is difficult to assess as costs continue to decline and markets are still in transition. But by the end of 2015, overall break-even thresholds could be down by as much as an additional $5/bbl compared with the Figure 4 projections. Certainty some reductions will be temporary—a factor of current market conditions. However, the degree to which cost reductions are longer-lasting will play a role in helping oil sands to maintain its relative competitive position in the world. Yet, reductions are being observed globally, and oil sands' competitive position may still shift. These issues are discussed in the following section.

## Oil sands' competitiveness

The Canadian oil sands figured prominently as a source of global supply growth over the past decade. However, rising cost structures and periodic pipeline constraints (which have reduced the prices that producers have been able to obtain for their crude oil) have lowered anticipated returns for producers, governments, and investors alike. The current lower global oil price environment is intensifying cost reduction efforts but still presents a fresh challenge for the industry.

In the aftermath of the collapse of oil prices in 2014, the oil sands is at a turning point—as is the entire global oil industry. Will lower prices drive material and sustainable cost improvements in the oil sands, or will cost pressures return with higher prices? What types of oil investment will see the greatest production decline—onshore, offshore, or the oil sands? Will the oil sands be able to compete with other sources of supply in the future?

This next section explores the factors that will help shape oil sands' competitiveness and longer-term trajectory of growth.

### Lower prices are slowing oil sands investment

The lower price environment poses a fresh challenge. Average oil prices in 2015, with WTI around $50/bbl, do not support the economics of new greenfield oil sands projects (see Figure 4). As a result, decisions on new projects have been deferred. However, by and large IHS expects both that projects in operation from before the price collapse will continue to operate and that projects under construction will be completed and brought online. At the beginning of 2015, nearly 1 MMb/d of production capacity was at various stages of construction in the oil sands. With the majority of this capacity expected online, IHS expects growth to continue through to 2020, when production is expected to exceed 3 MMb/d, up from an estimated 2.3 MMb/d in 2015. The longer-term growth trajectory depends not only on the timing of the global price recovery but also on the economics of future oil sands projects.[16]

14. Some oil sands producers have different cost reduction expectations; variability is to be expected. But another difference may be what is defined as cost. The IHS Upstream and Oil Sands Capital Costs Indices track only upfront capital construction costs. Oil sands operators will often include companywide cost reductions, such as from lower operating overhead, which can lead to some discrepancies.

15. As of November 2015, the US-Canadian exchange rate had fallen 18 cents since a high last July, when C$1.00 was worth about US$0.94 cents. The lower dollar has benefited Canadian producer revenues because oil is sold in US dollars and many expenses are paid in Canadian dollars. However, the weaker Canadian dollar has also made the cost to import key construction inputs, such as steel, equipment, and replacement parts, more expensive.

16. Since the price collapse began in November 2014, not including pilot or demonstraction projects, one project that had been under construction has been cancelled, one small project that was completed has been placed on hold, and another small-scale project has been shut-in. Some other projects under construction are being rescaled to lower capacity or being divided into multiple smaller projects to lower costs. However, these changes have not materially affected the IHS oil sands production outlook to 2020.

## Prices will eventually return to levels capable of supporting new projects

It will take time for global oil prices to recover. The price collapse of 2014–15 (or longer) has already lasted longer than the 2008–09 collapse. And it will likely be late 2016 or 2017 before the global oil supply glut is worked off. But cutbacks in investment today point to the possibility of weaker supply growth in the future, which could lead to higher prices—assuming that demand growth is steady and significant. The need to replace global production declines will eventually take hold, and adequate prices will be required to incentivize those higher-cost sources of supply in the world that will be needed to balance oil markets over the longer term. This includes not only oil sands but also deepwater offshore and non–North American tight oil, among others.

For the Canadian oil sands, prices will likely need to rise well above break-even levels—and remain there for a period of time—before significant new capital is committed to the construction of new greenfield projects.[17] With the least expensive oil sands projects in 2015 requiring a WTI price of around $50/bbl for SAGD expansions, it may be a year or more before prices could be sufficiently strong to support the economic sanctioning of expansions, let alone greenfield projects. However, if costs fall further, then the break-even price may become lower.

The pace of global demand growth, the dynamics of tight oil production, OPEC production policies, and geopolitics are among the myriad of variables that will help shape an oil price recovery. Throughout this period, the oil industry will struggle to understand a world without OPEC balancing the global oil market. Price volatility is to be expected and will complicate decisions on new projects.

## Oil sands' global competitive position may shift

The oil price is a key variable in determining the longer-term trajectory of oil sands growth. But so too is access to capital, for which the competition can be fierce. Indeed, lower oil prices are changing the competitive environment for global oil production.

Prior to the global price deflation, the break-even point for new oil sands projects, specifically SAGD, was within a competitive range to other key sources of global supply growth (see Figure 1). Low prices are now lowering costs globally. For example lower prices could push the average global capital cost for new oil projects down by as much as 20% over 2015 and 2016. Within this broad trend, the full-cycle cost—which includes capital costs as well as operating costs and government take—of particular sources of supply will decline at different rates. For example, costs for US tight oil production are expected to fall more than the global average. This differentiation suggests that some producing areas will gain competitive position while others will lose. In this world, if oil sands cost reduction efforts bear less fruit than efforts elsewhere, then oil sands' competitive position as an investment destination may shift. This could mean that, among companies that invest globally, projects in other regions could be prioritized over those in the oil sands.

## Factors supporting ongoing investment in the Canadian oil sands

Years of large-scale investment have expanded the service and the labor markets in western Canada. The industry approach to oil sands projects and growth is changing. Lower prices are also lowering costs and accelerating structural changes in the industry. How these factors could contribute to a more competitive sector in the future is discussed below.

- **Oil sands projects will, on average, be smaller-scale brownfield in-situ expansion projects.** After more than a decade of strong oil sands investment, sufficient infrastructure is now in place. As a result, production growth will be driven by expansion of existing projects rather than by greenfield developments. Over 70% of production growth during 2015–20 is expected to come from expansions, with over 80% of expansion growth coming from in-situ developments. Expansions are more manageable and predictable than greenfield projects because they are smaller, have shorter lead times, and require less labor.

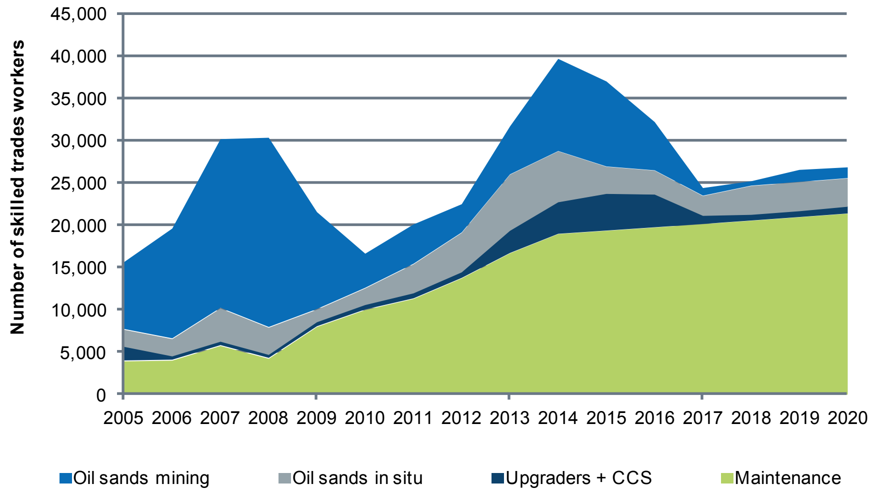
- **Future oil sands labor demand is expected to be lower.** Mines require a large number of workers. In the past, mines have taken four to five years to construct, with peak labor demand near 10,000 workers. More recent mining projects

17. During the previous downturn in 2008–09, some large producers chose to advance projects in the lower price environment to achieve cost savings. Although this is less likely in this downturn, it is still conceivable.

expect a more modest 5,000 workers on site. After the current mine projects under construction are complete, IHS does not expect a new greenfield mining project to advance (barring a transformational change in mining extraction technology). In 2017–18, around the time that labor from mines currently under construction will be finishing their job, IHS projects that oil prices may be entering a range that could justify sanctioning of greenfield oil sands projects. Without a new greenfield mine in the outlook, oil sands labor demand may never return to historical peaks (see Figure 5). This may help keep future labor costs in check.

Figure 5

**Estimate of oil sands labor demand (skilled trades workers), 2005–20**




Notes: Owing to data limitations before 2010, upgrader and carbon capture and storage workers are captured in mining and in situ, respectively.
Source: IHS Energy



- **Companies are redesigning projects for lower costs.** Oil companies are revisiting project designs and looking to greater standardization to lower upfront capital cost. Sustaining and operating costs are also being scrutinized for cost savings. Operators are looking to standardize replacement components to lower fabrication costs. Innovations that arise from these efforts may help moderate future cost pressures.

- **Service sector capacity has expanded with oil sands growth.** Years of oil sands growth resulted in an expansion not only of production infrastructure but also of service sector capacity. Fabrication yard capacity, for example, has expanded. Modular fabrication capacity—which allows projects to be constructed in pieces and then later assembled on site—expanded over 400% from 2000 to 2013.[18] As capacity has grown, fabricators have been more willing to enter into longer-term contracts, which in turn provides the industry with greater cost certainty.

- **Project proponents and service providers are adopting a more collaborative approach to project management.** The industry approach to project (and cost) management is also changing. Companies are spending more time advancing engineering and design before beginning construction and making greater efforts once construction is under way to minimize any reworking or reengineering. Project proponents and service providers, such as construction and engineering firms, are making efforts to collaborate more closely on projects. What may make the most sense from a design perspective may not always be the most cost effective to construct.

In many ways, the oil sands were a new industry in 2000. Many changes have occurred over the past 15 years. In addition to an expansion of improvements in infrastructure, service sector, and labor capacity, many lessons have been learned. The oil sands of the future will undoubtedly differ from the past.

## Other headwinds to growth

Although this report focuses almost exclusively on costs, other challenges are contributing to investor caution.[19] This includes market access and potential changes to the oil sands fiscal regime in Alberta.

Opposition to new pipeline development from western Canada has contributed to project delays and rejections. The Keystone XL pipeline, the highest-profile example, was recently denied a permit by the US government. The Northern

18. Extrapolated by IHS from Ekyalimpa, et al., *Model Assembly Capacity: A Study of Alberta Module Constructors,* 2014.

19. Such challenges are discussed in depth in the IHS Energy Special Report *Why the Oil Sands? How a remote, complex resource became a pillar of global supply growth.*

Gateway pipeline now faces the prospect that the Canadian government may deny access to marine tankers. The TransMountain pipeline expansion and Energy East pipeline continue to advance through the regulatory process but, like other pipeline proposals, have faced some degree of delay.

Insufficient pipeline access has forced oil sands producers to accept price discounts—at times steep—for their crude. The rise of crude by rail has established a ceiling for these discounts; but with the price to transport crude by rail exceeding pipeline costs, the greater price stability has not come without a cost.

IHS projects that for the time being western Canada producers should have access to sufficient pipeline capacity. Operational pipeline improvements in 2015, incremental pipeline capacity additions late in 2014, and ongoing production declines brought on by lower prices on conventional production should allow sufficient space in existing pipelines for current oil sands supply. However, at some point in 2016, supply could once again overtake available capacity, increasing price discounts for western Canadian crudes.

In addition, in recent months, the prospects of changes to the fiscal terms and more stringent carbon policies in Alberta moved up the list of challenges facing oil sands development. The June 2015 change in the Alberta government has brought tax, royalty, and carbon pricing to the fore. Since assuming leadership, the new provincial government has increased the corporate income tax from 10% to 12%, announced a plan to expand coverage and raise the price of greenhouse gas emissions, placed a cap on oil sands emissions at 100,000 metric tons, and launched a review of the provincial oil and gas royalty regime.[20] In summary, additional costs associated with taxes, and carbon pricing as well as uncertainty over the future shape of fiscal policies may add to investor caution.

## Conclusion: Toward a globally competitive industry

The oil sands industry has transformed from a niche investment opportunity to one of the most important sources of global oil supply growth. It is an economic engine not just for Alberta but also for Canada. In the earliest days of commercial development, success was about accumulating sufficient land and resource to make a commercial project viable. Then success shifted to constructing greenfield oil sands facilities, the period that is the focus of this report and of capital cost escalation. Now that significant infrastructure has been built over the past 15 years, the industry is shifting to a new period in which success will be measured by efficient operation of existing facilities. Growth will be driven by incremental expansions. The current lower price environment is abetting this transition as new projects are delayed and producers increasingly focus on best practices and operational excellence.

Ultimately, oil sands' competitive position will be shaped by local, regional, and global conditions—including changes to other sources of supply in the world. The challenge facing the oil sands is how much producers can lower their cost structures and the degree to which the pace of future cost escalation can be successfully managed. The oil sands industry—and the governments of Alberta and Canada—can make many changes, but in the global competition for capital, other sources of supply are not standing still.

20. In Canada, provinces typically control the development of natural resources within their borders.

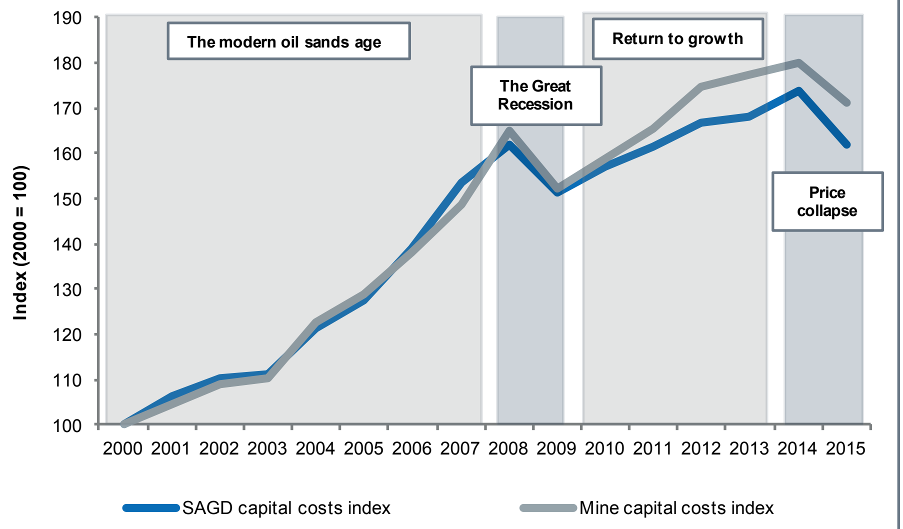
# Appendix: Oil sands' history of capital costs escalation in detail

Over the past 15 years, distinct periods of escalation have occurred (see Figure A-1). These are described below.

**The modern oil sands age (2001–08).** As oil prices appreciated in early 2000s, capital poured into the oil sands, kicking off the modern oil sands age. The first commercial SAGD project came online in 2001 and triggered growth with a new form of extraction. By 2008, SAGD accounted for about 23% of oil sands production.[21] From 2000 to 2008, annual oil sands capital investment in new projects rose from $4 billion to over $18 billion, and IHS estimates that capital costs rose 60%—the greatest period of cost appreciation over the past 15 years. From 2000 to 2008, the number of large oil sands projects in operation more than doubled, from 7 to 18, with construction advancing on several others. This included the expansion of both original mining operations and two completely new mines over this period. All of these mines included upgraders to convert bitumen to SCO, which added to project scale and costs.

Figure A-1

Oil sands capital costs indexes




Source: IHS Energy © 2015 IHS

As labor demand outstripped local and then regional labor supply, wages increased and productivity declined. From 2000 to 2007, the wage for skilled trades in Alberta increased 50% more than the national average—and nearly double what occurred in Ontario, Canada's most populous province.[22]

Labor pressures were amplified by difficulties with project execution. Many workers and companies were at an early stage of the learning and experience curve. Construction at times advanced at a pace that overtook design or that exceeded requirements by either using higher-cost materials or overbuilding in anticipation of future expansions. These missteps ultimately slowed construction, increased labor costs, and contributed to cost overruns.

The oil sands region also lacked adequate infrastructure such as roads and power lines, which had to be built to support growth. This contributed to additional activity, exacerbating demand for labor and material, and helped to push costs higher. This was a period of construction, development, and learning, with many companies advancing their first oil sands in-situ or mining project.

**The Great Recession (2008–09).** The global financial slowdown and the subsequent dramatic, but ultimately short-lived, reduction in global oil prices slowed investment for a time. The price of WTI lost three-quarters of its value, from a high in July 2008 above $140/bbl to under $40/bbl by December. Annual investment in new oil sands projects fell 40%, or $7 billion, between 2008 and 2009. Unsanctioned projects were delayed and some new project construction halted, leading to concern about the economic viability of future growth. Yet, oil sands production growth continued through this period as many projects already under development proceeded to completion, including a mine expansion and three SAGD projects. Projects that continued through the downturn were able to realize cost savings, because the global slowdown helped eased some cost pressures as investment slowed. The labor market loosened, allowing access to more efficient equipment and workers, allowing some companies to realize productivity gains. Overall IHS estimates that capital costs fell by about 6% from 2008 to 2009. However, the cost of some construction inputs, such as steel and pipe, fell by as much as 25%.

21. Production is defined here as raw bitumen, not marketed products.

22. Source: Statistics Canada. Table 282-0069 - Labor force survey estimates (LFS); accessed 15 August 2015.

**The return to growth: 2010–14**. By late 2009, oil prices were recovering, and the oil market entered a period of remarkable price stability. Between 2010 and mid-2014, WTI ranged between $80/bbl and $110/bbl.[23] From 2010 to 2013, annual capital investment in oil sands project development nearly doubled, from $17 billion to $30 billion, as construction accelerated. Along with reinvigorated growth, cost pressures returned as labor demand reached new heights. By 2012, the capital costs for mine and SAGD projects exceeded their pre-recession level. Yet toward the end of this period, there were signs of slowing cost appreciation. For example, prior to the Great Recession, in 2007 capital costs appreciated around 7% per year. In 2010–12, annual capital cost appreciation was lower, at around 4%. Capital cost inflation decelerated further, to around 2% in 2013–14. Years of investment to build regional infrastructure and expand labor market and service sector capacity helped keep a lid on cost escalation. Also, the oil sands industry had matured. Companies had become more aware of factors that contributed to historical cost escalation, such as that labor productivity declines as projects exceed certain scale, and had grown more institutionalized in their approach to new projects. Other global factors, such as an oversupplied steel market, also helped keep capital costs in check.

**The price collapse and the industry at a turning point: 2015+.** The next chapter in oil sands capital costs is being written as the industry copes with the reality of a low price environment, even as costs are declining. This is discussed in the report's final section.

23. Prices ranged from a low of about $70/bbl in 2010 to above $110/bbl in 2011, but on a weekly average basis, prices were between $80/bbl and $110/bbl 88% of the time from 2010 to mid-2014.

## Report participants and reviewers

IHS hosted a focus group meeting in Calgary, Alberta, on 23 October 2014 to provide an opportunity for oil sands stakeholders to discuss perspectives on the key factors that contributed to oil sands growth. Additionally, several key stakeholders participated in a survey that helped form this analysis. A number of participants also reviewed a draft version of this report. Participation in the focus group or review of the draft report does not reflect endorsement of the content of this report. IHS is exclusively responsible for the content.

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Natural Resources Canada

Shell Canada

Suncor Energy Inc.

TD Securities Inc.

TransCanada Corporation

## IHS team

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**Jeff Meyer,** Associate Director, IHS Energy, focuses on the global oil market and industry trends. Prior to joining IHS, Mr. Meyer was a correspondent for Dow Jones Newswires, based in Shanghai, where he covered China's capital markets and economy. At Dow Jones he also contributed to *The Wall Street Journal*. He has held short-term positions with J.P. Morgan's Emerging Asia economic research team and with the US Treasury's Office of South and Southeast Asia. Mr. Meyer holds a BA from Haverford College and master's degrees from New York University and from Johns Hopkins University School of Advanced International Studies. He is proficient in Mandarin.