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The Canadian Oilsands and Strategic Approaches to Profitability

1. Introduction

The oil price collapse in mid-2014 and ongoing sluggishness in the price recovery have tempered a lot of the excitement that drove capital investments of over C$217 billion to date[1] in the Canadian oilsands. Compounded by increasing limitations in pipeline access, whether to the United States, or across the east and west of Canada, the oilsands market does not seem nearly as attractive to foreign investors as it once did. Several international companies, including Shell, BP and Statoil (now Equinor) have sold most of their operating assets and chosen to become non-operating partners in existing ventures, if at all. Others like Exxon-Mobil have written down the values of their assets, reflecting lower expectations for future development and investment.[2] Yet others, like Chevron, have exited the Canadian oil and gas market altogether. This has raised fears that, barring major socioeconomic changes, oilsands reserves could be stranded very quickly.[3]

The emergence of light tight oil (LTO) in the United States has added more pressure on an already shaky Canadian oilsands investment market. With a more favourable investment environment,[4] shorter investment cycle, better access to markets, and the potential for faster returns; most of the capital spending on oil & gas projects in North America occurs in the US. New investment in the oilsands has largely been led by Canadian producers, especially Suncor, Canadian Natural Resources Limited (CNRL), Imperial Oil and Husky Energy. The only significant non-Canadian players are coming from China, and there are questions about whether their investment is for economic or political gain.[5]

Environmental concerns have also weighed on the debate about the future of the oilsands. Canada has been a strong supporter of the Paris agreement, committing to reducing its greenhouse gas (GHG) emissions by 30 per cent from the 2005 level by 2030. In 2014, Canadian emissions totaled 738 megatonnes (MT), which represented 1.63 per cent of the global total.[6] While overall GHG

[1] Natural Resources Canada. *Oil Sands: Economic contributions.* July 7, 2016. https://www.nrcan.gc.ca/energy/publications/18756 (accessed November 4, 2018).
[2] Yedlin, Deborah. "ExxonMobil's massive reserve writedown not reason for oilpatch panic." *Calgary Herald.* February 24, 2017. https://calgaryherald.com/business/energy/yedlin-exxonmobils-massive-reserve-writedown-not-reason-for-oilpatch-panic (accessed January 26, 2019).
[3] Debarre, R, T Fulop, and B Lajoie. 2016. "Consequences of COP21 for the Oil and Gas Industry." *Accenture Strategy.* Accessed December 1, 2017. https://www.accenture.com/t20160527T044626Z__w__/us-en/_acnmedia/PDF-11/Accenture-Strategy-Energy-Perspectives-Consequences-COP21.pdf.
[4] Findlay, J. Peter. 2016. "The Future of the Canadian Oil Sands." *Oxford Institute for Energy Studies Paper: WPM 64*, August.
[5] Lunau, Kate. 2012. "Our Chinese Oil Sands." *Macleans Magazine.* August 8. Accessed January 26, 2019. https://www.macleans.ca/economy/business/our-chinese-oil-sands/.
[6] Government of Canada. 2018. *Greenhouse gas emissions.* June 6. Accessed December 1, 2018. https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions.html.

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emissions in Canada have been decreasing (704 MT in 2016), the amount from the oilsands has been increasing. Despite energy intensity of a barrel of oil from the oilsands decreasing by 31 per cent since 1990, an increase in the number of projects and overall production has resulted in oilsands GHG emissions increasing from 15.4 MT in 1990 to 72 MT in 2016.[7] In what has been hailed as one of the most ambitious climate policies of any jurisdictions in North America, the government of Alberta rolled out a climate leadership plan that among other things, requires oilsands emissions to be capped at 100 megatonnes (MT) per year.[8]

The biggest threat that has emerged to the continued near-term profitability of the industry is the lack of sufficient market access. Oilsands companies are heavily dependent on international markets, as the refining capacity in Canada is not enough to sustain current, let alone future, production. Until 2008, market access was not a significant concern for the oilsands industry. There was a view among some analysts and scholars that although pipelines would see some initial bottlenecks as new oilsands projects were commissioned, there could end up being some spare pipeline capacity by 2009.[9] However, several oilsands projects have increased production well beyond their original nameplate design. For example, Suncor's Firebag and MacKay River facilities increased their nameplate performance from 180,000 b/d to 203,000 b/d and 28,000 b/d to 38,000 b/d over the last five years, respectively, through debottlenecking activities.[10] Other operators like Cenovus Energy and Imperial Oil have undertaken similar moves over the same horizon. While doing this provides significant benefits – primarily reducing operating costs per barrel – it also increases the volume of oil available on the market.

The focus of this Energy Insight will be on the levers within the control of oilsands firms, and how effectively they have been deployed to sustain profitability during this turbulent period. These will help shed light on the long-term viability of Canada's single largest industry continuing to be a significant contributor to the Canadian economy and a key source of non-OPEC supply.

2. Canadian Oilsands: Contemporary Performance

Before analyzing the long-term economic viability of the oilsands industry, and what companies can do to assure that, it is worth examining contemporary performance between 2013 and 2017. The upheaval witnessed by the global oil market during this period was quite unprecedented for such a short amount of time, with benchmark oil prices tumbling from highs well over US$100 per barrel to lows of US$26 per barrel in less than two years, before recovering in fits and starts. The Canadian market was even more chaotic, due to the external pressures referenced earlier.

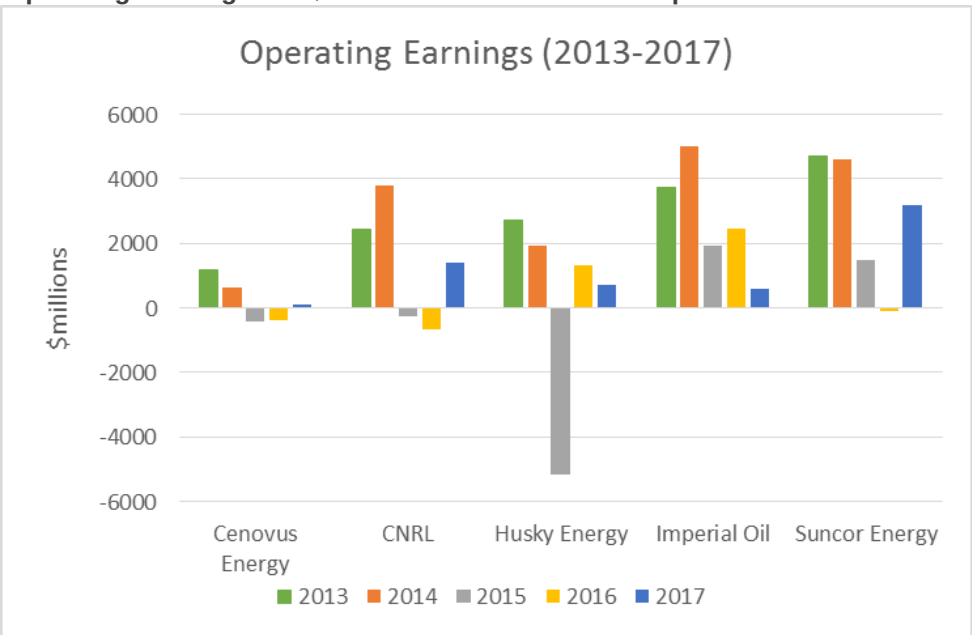
Financial data from the five major oilsands players which control nearly 80 per cent of Canadian production – Cenovus Energy,[11] Canadian Natural Resources Limited (CNRL),[12] Husky Energy,[13] Imperial Oil[14] and Suncor Energy[15] – provides a good view of the economic fundamentals of the

[7] Ibid
[8] Government of Alberta. 2016. *Capping oil sands emissions.* Accessed November 30, 2018. https://www.alberta.ca/climate-oilsands-emissions.aspx.
[9] Humphries, Marc. 2008. *North American Oil Sands: History of Development, Prospects for the Future.* Prepared for the Congressional Report Service (CRS), Diane Publishing Co.
[10] Suncor Energy Press Release. 2016. *Suncor Q4 2015 Oil Sands Update: Firebag Nameplate Capacity Increased and Substantial Completion of Detailed Engineering Work at Fort Hills.* February 3. Accessed January 25, 2019. http://www.canoils.com/Universal/View.aspx?type=Story&id=128993.
[11] Cenovus Energy Annual Reports. "Annual Reports (2013-2018)." *Cenovus Energy.* 2014-2019. https://www.cenovus.com/invest/financial-information/annual-reports.html (accessed May 1, 2019).
[12] CNRL Annual Reports. "Annual Documents (2013-2018)." *Canadian Natural Resources Limited.* 2014-2019. https://www.cnrl.com/investor-information/annual-documents.html#2017 (accessed May 1, 2019).
[13] Husky Energy Annual Reports. "Reports & Filings (2013-2018)." *Husky Energy.* 2014-2019. https://huskyenergy.com/investors/reports-filings.asp (accessed May 1, 2019).
[14] Imperial Oil. "Imperial Investor Day Presentation." *Imperial Oil.* November 7, 2018. https://cdn.imperialoil.ca/~/media/imperial/files/company/ir/speeches/2018_investor_day_presentation.pdf (accessed February 8, 2019).

overall industry. Key measures to be considered include operating earnings, cash flow from operations, segmented earnings for both upstream and downstream business units; realized price for oilsands barrels and oilsands cash operating costs.

Operating earnings are shown in Figure 1. While this includes non-oilsands segments, it reflects the overall financial health of companies with significant oilsands operations. Overall, the companies made a combined operating profit of C$37 billion during the five-year period. The most challenging years were 2015 and 2016, but Imperial Oil averaged over C$2.1 billion in annual operating profit, compared to C$670 million for Suncor Energy and losses for the other major players over those two years.

Figure 1: Operating Earnings in C$ for Selected Oilsands Companies

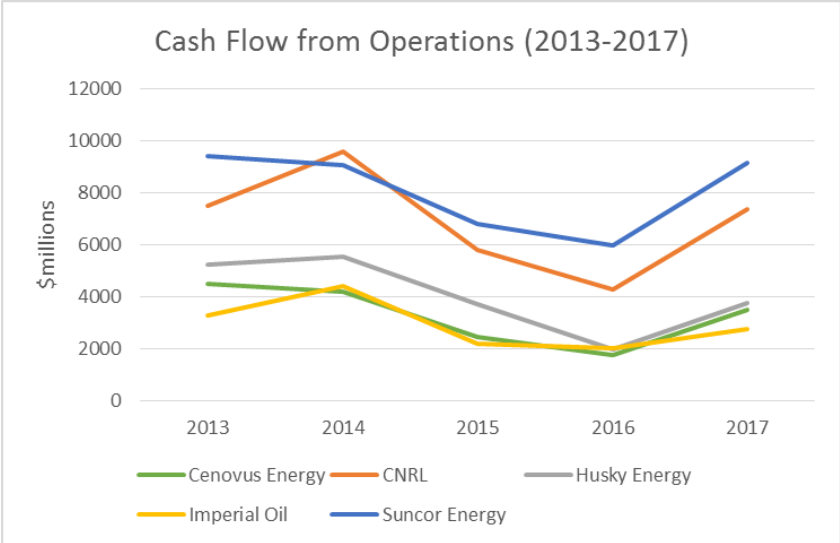


Source: Corporate Annual Reports

Cash flow from operations is another measure favoured by oilsands companies as it is often used to show investors the company's ability to generate funds and keep operations going. Despite decreases in 2015 and 2016, the major Canadian oilsands companies maintained fairly strong cash flow generation throughout the period. This cash was used to prop up projects and operations even when investors experienced concerns about investing in the industry in the wake of oil price declines.[16] Figure 2 show the cash flow from operations, and the trend indicates that by the end of 2017, cash flows for most companies were approaching the levels seen in 2013, when WTI was over US$100 per barrel, even though WTI averaged just over US$66 per barrel in 2017.

[15] Suncor Energy Financial Reports. "Financial Reports (2013-2018)." *Suncor Energy.* 2014-2019. https://www.suncor.com/investor-centre/financial-reports (accessed May 1, 2019).
[16] Bakx, Kyle. "The Great Oilsands Era is Over." *Canadian Broadcasting Corporation.* September 17, 2018. https://newsinteractives.cbc.ca/longform/the-great-oilsands-era-is-over (accessed March 9, 2019).

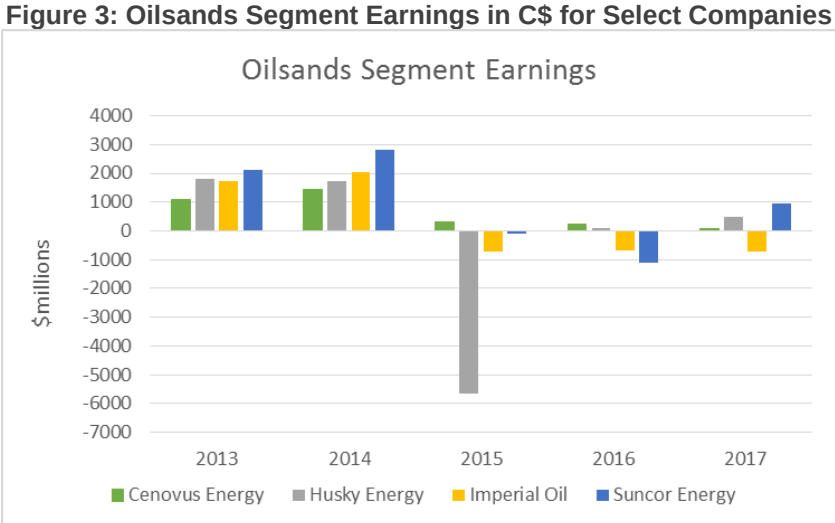
Figure 2: Cash Flow in C$ for Selected Oilsands Companies



Source: Corporate Annual Reports

With largely healthy operating earnings and cash flows, it's important to understand whether funds are being generated from oilsands or refining operations. Although CNRL does not provide operating profit by segment, data from the other four companies are available, and can be used to objectively analyze sector profitability. For oilsands segments, shown in Figure 3, the picture is relatively mixed since 2014. Cenovus has retained net operating profits from 2015 to 2017, albeit at a decreasing rate. Husky, which impaired several operating assets/projects in 2015, has been profitable otherwise. Imperial Oil has reported operating losses since 2015, driven by reliability issues at the Syncrude facility. This has also prevented them (and partner Suncor) from capturing the full value of the premium commanded by the Syncrude Light Sweet blend.

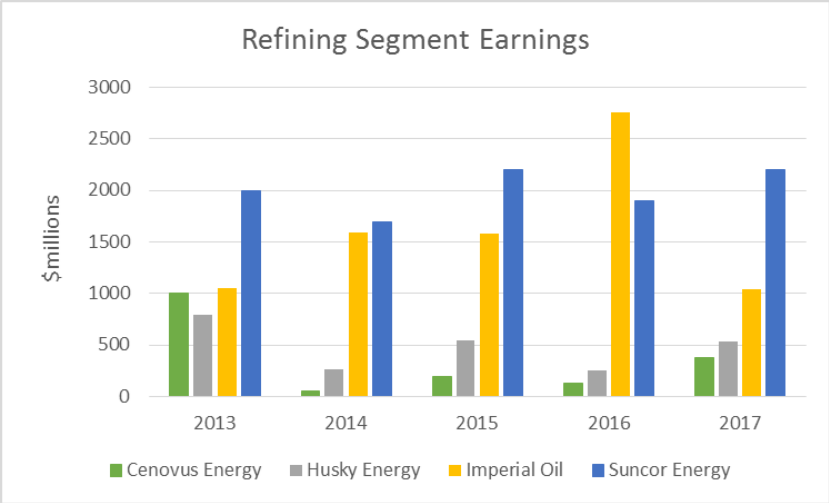
Figure 3: Oilsands Segment Earnings in C$ for Select Companies



Source: Corporate Annual Reports

Refining segment earnings are shown in Figure 4. For Imperial Oil and Suncor, which are truly vertically integrated, if oilsands and refining are looked at as *two parts of one whole*, rather than two separate entities; it's logical to make the case that the *whole* has remained very profitable despite one of the most challenging periods for the Canadian energy sector in recent memory.

Figure 4: Refining Segment Earnings in C$ for Select Companies (source - Annual Reports)



Source: Corporate Annual Reports

Overall, then, it would appear that oilsands companies are profitable. Cash flow in particular is quite important in the context of reduced investment, restricted ability to raise external finance, and the need for companies to fully fund operations and sustaining projects. The best view of this facility-driven cash flow can be had by measuring the realized price and cash cost – both on a per barrel basis.

Realized price is what the producing company receives for a barrel of oil at the initial point of sale. Generally, the main drivers for this price are the sulphur content and specific gravity. With oilsands, other factors such as the transportation mode and destination play a significant role in the realized price. In addition, for companies that produce bitumen – increasingly becoming the default oilsands blend – condensate or other diluents must be purchased and blended with the bitumen to reduce its viscosity. The resultant crude is similar to WCS, which consists of 75 per cent bitumen and 25 per cent condensate/light oil, but with lower price realizations relative to WTI. Table 1 shows the annualized prices for major crude blends between 2013 and 2017, along with the US/Canadian dollar exchange rate over the same time.

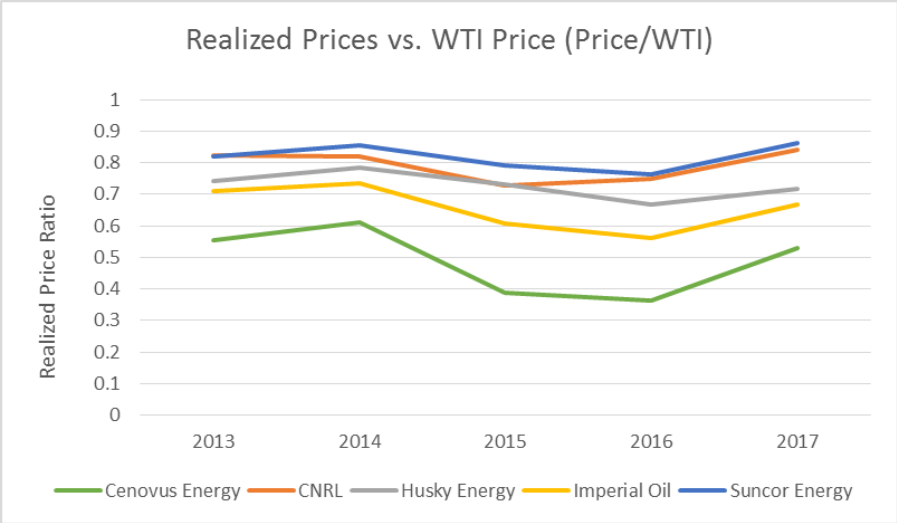
Table 1: Benchmark Prices for 2013-2017

Benchmark Prices for Crude Oil Blends and US$/Cdn$ Exchange Rates (2013-2017)					
	2013	**2014**	**2015**	**2016**	**2017**
Dated Brent (US$/bbl)	108.75	99.03	52.35	43.75	54.25
West Texas Intermediate (WTI) at Cushing (US$/bbl)	97.95	93	48.75	43.35	50.95
Western Canadian Select (WCS) at Hardisty (US$/bbl)	72.75	73.6	35.25	29.55	38.95
Mixed Sweet Blend (MSW) at Edmonton (Cdn$/bbl)	96.8	94.85	57.6	51.9	63.2
US$/Cdn$ Exchange Rate	0.97	0.91	0.78	0.75	0.77

Source: Suncor annual reports, CME Group and the Government of Alberta

As seen in Figure 5, realized prices for oilsands companies over the analyzed period have trended in line with the changes seen in commodity prices, worsened by the increasing challenges some companies have in getting their product to market. CNRL and Suncor have the most success capturing the maximum value for their oilsands crude. Although both companies have sweet crude production, the average realized price is weighted down by bitumen which must be blended with condensate before transportation. Husky upgrades 50% of its bitumen/heavy oil to synthetic crude oil (SCO), capturing 75% of the WTI price on average. Imperial Oil receives a 30–35 per cent discount to WTI, likely because its production is weighted heavily in favour of bitumen, with a positive offset from the light-sweet crude premium its 2 per cent share of Syncrude provides. For Cenovus, which produces diluted bitumen only, realized prices are even lower.

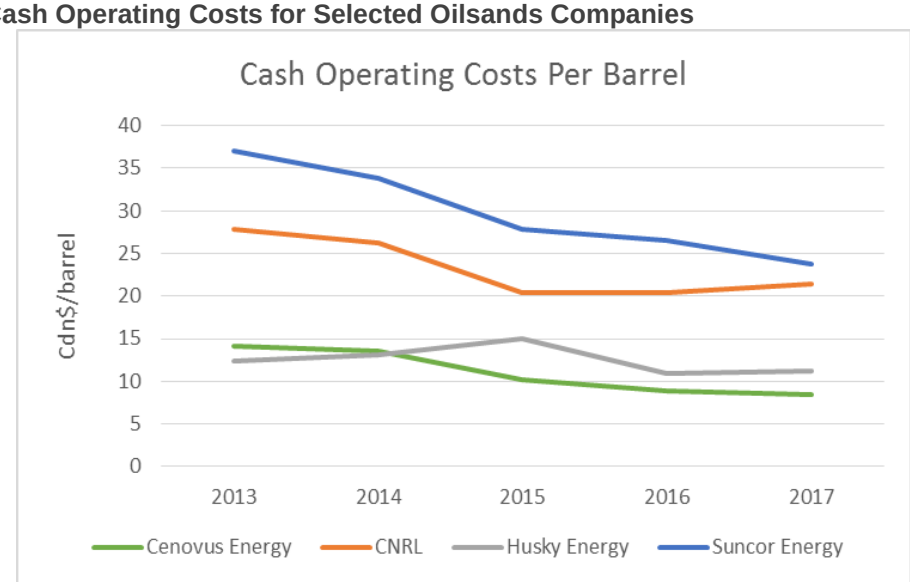
Figure 5: Realized Prices as a ratio of WTI Prices



Source: Corporate Annual Reports

Figure 6 shows the cash costs per barrel for selected major oilsands players between 2013 and 2017. Cash cost per barrel (CCB) is the cost of operating the facility, including commodity costs – usually natural gas and chemicals – and other operations costs, such as maintenance activities, operating expense projects, waste disposal and functional support. Bitumen-heavy producers have achieved significant cost reductions over the last five years. Cenovus, for example, produced a barrel of bitumen for C$8.40 in 2017, while Husky produced one for C$11.27. In addition, although Suncor's overall oilsands cash costs are over C$20 per barrel due to mining and upgrading, its in-situ facilities combined to produce bitumen for under C$9 per barrel.

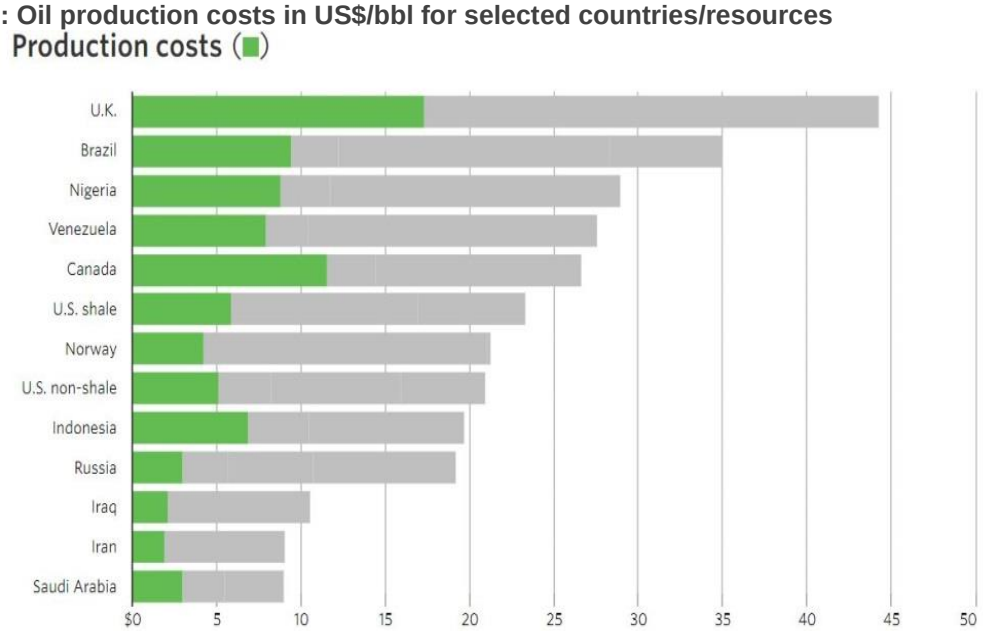
Figure 6: Cash Operating Costs for Selected Oilsands Companies



Source: Corporate Annual Reports

The significance of this improvement in operating cost performance cannot be overstated. As seen in Figure 7, Canadian oil – driven by oilsands – has the highest proportion of operating costs per barrel in the world, and in real terms is only below the North Sea region.

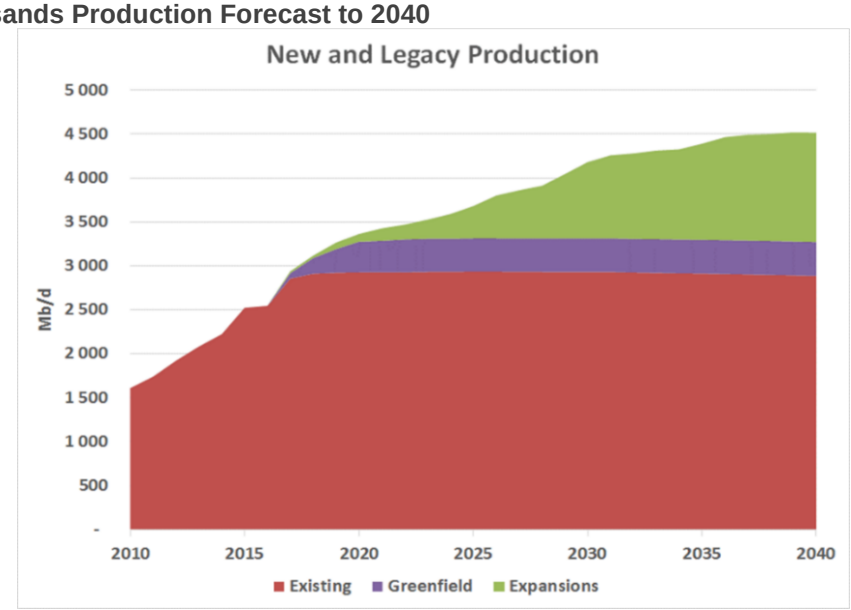
Figure 7: Oil production costs in US$/bbl for selected countries/resources



Source: Rystad Energy UCube

Most oilsands facilities are built to last for forty years or more, with decline rates of less than 2 per cent annually. By comparison, LTO has wellsite decline rates of 15 percent or more annually.[17] With few large greenfield oilsands projects expected long-term,[18] the focus is on maintaining reliable production and unlocking value from existing facilities to spur growth, as shown in Figure 8.

Figure 8: Oilsands Production Forecast to 2040



Source: NEB, Canada

[17] Ngai, Catherine. "Mind the Drop: Decline Rates From Maturing Oil Wells on the Rise." *Bloomberg.* October 9, 2018. https://www.bloomberg.com/news/articles/2018-10-09/mind-the-drop-decline-rates-from-maturing-oil-wells-on-the-rise (accessed February 28, 2019).

[18] Findlay, J. Peter. "A restrained optimism in Canada's oil sands." *Oxford Institute for Energy Studies Energy Insight: 17*, August 2017.

3. Operational Drivers & Strategic Approaches

The operational performance – and massive profits – delivered by the five major oilsands firms during the 2013 to 2017 period has not gone unnoticed,[19] but it has been little understood or explained. Deconstructing the operational bottom line into fundamental elements will enable a closer view of what the major firms have done to drive performance in each area.

3.1 Operational Drivers

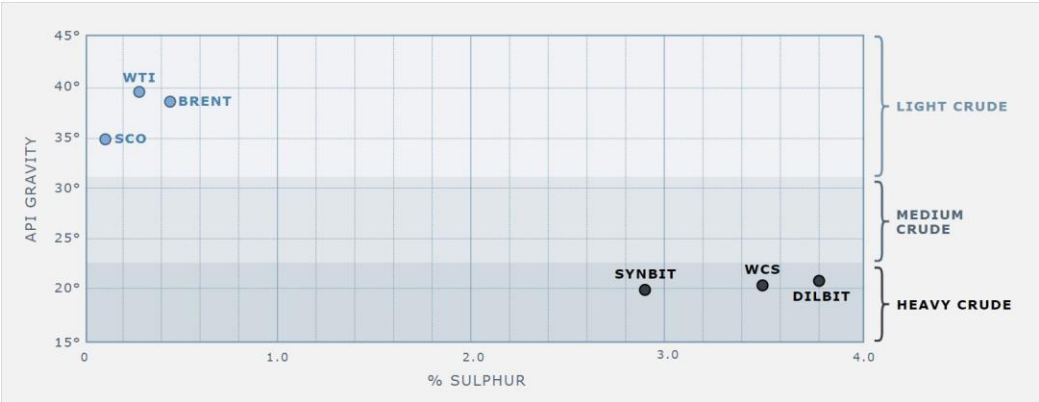
The driver of operational cash flow is the netback received on each barrel of oil, comprising the difference between the realized price and the sum of operating costs, capital costs, royalties and taxes.

Realized Price

While the market price for crude oil is an external factor beyond the control of oilsands firms, most companies have worked on increasing their average realized price to improve the netback received from sales. This has been achieved through increased production of higher margin crudes, acquiring or exploiting assets to improve the value chain of a produced barrel and securing midstream pipeline space to minimize transportation costs.

Product-wise, Canadian oilsands grades are heavily weighted towards the heavy and/or sour profile as shown in Figure 9. However, some Canadian blends are upgraded to light sweet SCO, and can capture price points on par with WTI and other lighter US blends. Examples include the Albian Heavy Synthetic and the Syncrude Sweet Premium, both of which are often priced higher than WTI and close to Brent crude prices.[20]

Figure 9 - Crude Blends (API vs. Sulfur content)



Source : Oilsands Magazine

Between 2016 and 2018, Suncor increased its share in the 350,000 b/d Syncrude joint-venture from 12 per cent to 58 per cent,[21] while CNRL acquired the Albian mine from Shell Canada and also purchased a 70 per cent stake in Shell's Scotford upgrader, where the Albian bitumen is upgraded to

[19] CBC News. "Alberta oilsands producers 'incredibly profitable' during recent economic downturn." *Canadian Broadcasting Corporation.* November 8, 2018. https://www.cbc.ca/news/canada/edmonton/oilsands-husky-cnrl-cenovus-imperial-parkland-institute-report-edmonton-1.4896996 (accessed November 24, 2018).

[20] Oilsands Magazine. *Products from the Oilsands.* April 6, 2017. https://www.oilsandsmagazine.com/technical/product-streams (accessed March 1, 2019).

[21] Suncor Energy. "Suncor Energy acquires additional interest in Syncrude and interest in Norway's Fenja field." *Suncor Energy.* February 12, 2018. https://www.suncor.com/newsroom/news-releases/2174399 (accessed January 26, 2019).

Albian Heavy Synthetic.[22] Already operating upgraders that produce a variety of sour and sweet crudes, both companies have been able to balance their operational profile between bitumen, heavy sour crude and light sweet crude production.

Oilsands companies that have downstream segments can also obtain higher margins from the sale of refined products like gasoline, diesel and kerosene. However, this value capture is significantly higher for those firms that are vertically integrated, i.e. with pipelines connecting their upstream operations with the refining complexes. In this regard, two Canadian companies – Imperial Oil and Suncor Energy – stand out. Imperial Oil's Strathcona refinery is connected to its Kearl mining and Cold Lake in-situ facilities; and bitumen from both can be routed there when required to take advantage of light-heavy differentials in the crude market. With the expansion of Enbridge's Line 9 from Sarnia to Montreal, shown in Figure 10, all four of Suncor's refineries can process sweet and sour SCO directly transported from its oilsands facilities.

Figure 10: Expansion of Enbridge Line 9

Source: Enbridge

Earlier in the decade, Suncor also added a decoking unit to its 150,000 b/d Edmonton refinery, allowing that facility to directly process non-upgraded bitumen feedstock. CNRL's takeover of the Albian mine and the Scotford upgrader, both formerly owned by Shell Canada, was also performed with improved value capture in mind. In addition, the company is a 50 per cent owner of the trouble-plagued Sturgeon refinery, and is slated to supply 25 per cent of the bitumen feedstock that will be processed once that refinery is operational. Both Cenovus and Husky have refineries, and while these are not directly linked to their operations (Husky's refineries in the US Midwest process SCO but incur high transportation costs), these facilities provide the companies with the ability to process cheaper feedstock and counterbalance the lower revenues received for bitumen with higher margins on refined product streams. Husky has an upgrader, but only about 50 per cent of its bitumen can be upgraded, limiting the value that can be captured from its increasing bitumen production. Cenovus increased its share of the Christina Lake and Foster Creek projects from 50 per cent to 100 per cent, increasing ownership of a low cost resource by buying out ConocoPhillips.

Suncor owns or has dedicated pipeline space for nearly 100 per cent of its production,[23] one of the few oilsands companies in that enviable position. CNRL also owns two pipelines and most of the other large producers have secured long-term leases on pipelines for some of their production. As new production has been brought online in the last few years, demand for pipeline space has

[22] Canadian Press. "Shell to sell Canada oilsands assets to Canadian Natural Resources in $7.2 billion deal." *Financial Post.* March 9, 2017. https://business.financialpost.com/commodities/energy/shell-to-sell-all-but-10-of-canada-oilsands-assets-to-canadian-natural-resources-for-7-2-billion (accessed January 25, 2019).
[23] Williams, Steve. "Visible strategy execution: how Suncor is defining performance." *Suncor Energy* . September 5, 2018. https://www.suncor.com/newsroom/speeches/7400 (accessed February 8, 2019).

outstripped supply, with estimated takeaway pipeline space at 3.95 mb/d[24] compared to production – including conventional oil – of over 4.5 mb/d. Oilsands companies with dedicated pipelines or long-term contracts – and fixed transportation cost structures – are better able to access coveted markets like the US Gulf Coast, where they can capture higher price points than those obtained by competing for limited pipeline space in Canada.

Operating Costs

One of the most impressive strides made by oilsands companies since the global price collapse in mid-2014 has been the reduction of operating costs. Several factors have played into the hands of Canadian producers, primary among them being the fact that the Canadian dollar depreciated by about 30 per cent against the US dollar over that time. In addition, the cost of labour returned to controllable levels, as did the cost of accommodations, materials and other logistics. The biggest improvement in cost management, however, has been in the operational CCB. The ability of oilsands producers to cut operating costs, and how sustainable these cuts are, is a topic market analysts and investors are interested in.

Cenovus Energy decreased its operating costs by 40 per cent between 2013 and 2017. Cost reductions at Cenovus have been driven by extending major maintenance windows, renegotiating contracts with suppliers and debottlenecking operating facilities without adding overhead costs.[25] Although realized oil prices decreased at a faster rate between 2014 and 2016, this cost approach has allowed the company to remain profitable – in fact, it is the only one of the Canadian majors to have positive operating earnings from its oilsands segment over the 2013 to 2017 period. In this, the quality of the Christina Lake reservoir, with its low steam-to-oil ratio (SOR), gives Cenovus an advantage over its large in-situ peers. A low SOR minimizes the volume of natural gas – the most expensive commodity in in-situ operations – that has to be used to generate steam.

Like Cenovus, CNRL rationalized its maintenance spend and extended windows for maintenance events. The company also realized efficiencies of scale from the debottlenecking of its Horizon mine and upgrader. Finally, as one of the largest producers of natural gas in Canada, CNRL increased the supply of its own natural gas to its bitumen facilities,[26] capturing value on the retail-wholesale differential. These led to operating cost reductions of 42 per cent between 2013 and 2016.

Suncor has cut CCB by 36 per cent since 2013 and largely sustained that reduction even after oil prices recovered in 2017. Key drivers for cost decreases have been workforce reductions, optimization of preventative maintenance and turnaround maintenance windows, and price (and volume) reductions for chemicals in its in-situ business unit. The company also introduced autonomous haul trucks for its mining operations, a move which is expected to reduce operating costs by C$1 per barrel.[27]

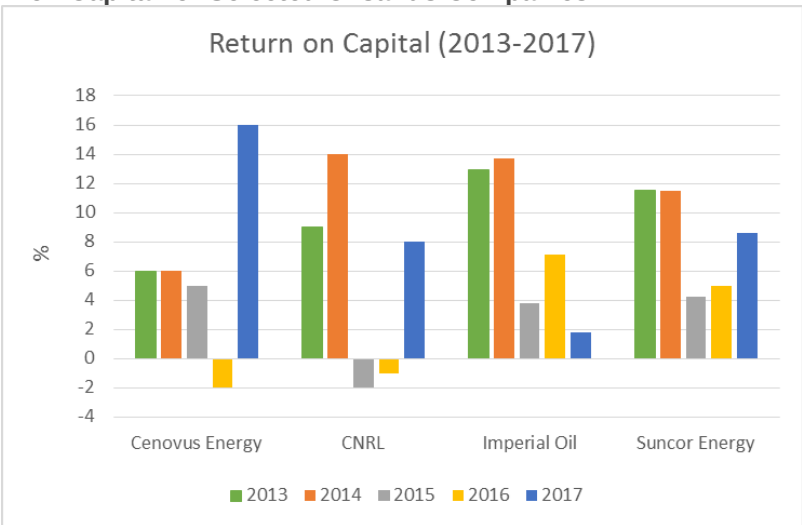
Husky, which reduced operating costs by 25 per cent between 2015 and 2017, achieved the majority of these through the debottlenecking of its Sunrise and Tucker thermal/in-situ facilities. The company has also tried to purchase existing, operationally efficient facilities, ultimately failing with a hostile takeover of MEG Energy, another low-cost bitumen producer.[28]

[24] Natural Resources Canada. *Crude Oil Facts.* September 13, 2018. https://www.nrcan.gc.ca/energy/facts/crude-oil/20064 (accessed March 1, 2019).
[25] Cenovus Energy Annual Reports. "Annual Reports (2013-2018)." *Cenovus Energy.* 2014-2019. https://www.cenovus.com/invest/financial-information/annual-reports.html (accessed May 1, 2019).
[26] CNRL Annual Reports. "Annual Documents (2013-2018)." *Canadian Natural Resources Limited.* 2014-2019. https://www.cnrl.com/investor-information/annual-documents.html#2017 (accessed May 1, 2019).
[27] Suncor Energy. "Q2 2018 Report." *Suncor Energy Quarterly Reports.* 2018. https://www.suncor.com/investor-centre/financial-reports/quarterly-reports (accessed March 1, 2019).
[28] Morgan, Geoffrey. "No white knight emerging for MEG Energy as Husky closes in." *Financial Post.* December 20, 2018. https://business.financialpost.com/commodities/energy/no-white-knight-emerging-for-meg-energy-as-husky-closes-in (accessed January 28, 2019).

Capital Costs

Companies have also placed a premium on reducing capital costs for new and sustaining projects, of particular importance given the recent challenges with raising foreign investment. As of 2014, the break-even cost for most SAGD projects was US$60 per barrel for WTI. In 2017, Cenovus announced that its break-even cost for new SAGD projects was US$40 per barrel. Suncor announced even more drastic improvements, with a break-even WTI cost of US$37 per barrel.[29] Most companies have implemented more rigorous capital program approvals processes, to ensure that only the very best projects are being sanctioned for execution. Despite a challenging market, this has resulted in solid returns on capital across the board, as shown in Figure 11.

Figure 11: Return on Capital for Selected Oilsands Companies



Source: Corporate Annual Reports

Modularized designs for new in-situ facilities have helped to shave engineering, procurement and construction costs. The Fort Hills project majority-owned by Suncor, which achieved first oil nearly six months ahead of schedule[30] was mostly designed and built in South Korea, with final assembly taking place at the operating site. In-situ well pad designs have also been standardized within each company, and in some cases shared across companies, to incorporate lessons learned and align operating and maintenance practices. Forums like the Canadian Oilsands Alliance (COSIA) have helped companies share ideas and partner on initiatives to optimize design and improve operational efficiencies.

Royalties & Taxes

The benefit of lower benchmark prices has been royalty reductions for producers, since rates are linked to the oil price under the Alberta government's sliding scale. In addition, taxes are lower when revenues are lower, resulting in lower taxes per barrel for the same production output.

3.2 Strategic Approaches

The operational drivers – and the manner in which they have been leveraged – allow us to summarize and categorize the strategic approaches taken by the five major oilsands players to withstand the unique challenges and opportunities facing the industry. These are cost leadership, vertical integration or an ambitious combination of both.

[29] Snyder, Jesse. "Breakeven costs of US$40 — and falling — means it's too soon to count out the oilsands." *Financial Post.* September 9, 2017. https://business.financialpost.com/commodities/energy/more-than-just-a-glimmer-of-hope-lower-costs-suggest-its-too-soon-to-count-out-the-oilsands (accessed November 8, 2018).

[30] Jaremko, Deborah. "Fort Hills hits nameplate capacity months ahead of schedule." *JWN Energy.* June 8, 2018. https://www.jwnenergy.com/article/2018/6/fort-hills-hits-nameplate-capacity-months-ahead-schedule/ (accessed July 30, 2019).

Cost Leadership

This is the preferred strategic approach for oilsands companies that are almost completely dependent on the market for their realized price, with little flexibility to sell bitumen or upgrade it into more valuable crude oil grades. This profile fits the vast majority of medium and smaller oilsands companies with no upgraders or dedicated pipeline space, for example MEG Energy, PetroChina and Athabasca Oil. Of the large firms, Cenovus and – for now – CNRL, appear to be pursuing cost leadership as well. Cenovus has doubled down on this strategy, with the attainment of full ownership of the former in-situ joint-ventures with ConocoPhillips at Foster Creek and Christina Lake. Shell's desire to leave the Canadian oilsands sector in 2016 presented CNRL with an opportunity to further solidify its upstream operations focus by acquiring reliable oilsands barrels. Looking forward, the company's 50 per cent stake in the Sturgeon refinery may position it towards a more vertically integrated or combined strategic approach.

Vertical Integration

Companies pursuing this approach are more focused on capturing the highest prices for their crude oil production than on pure cost leadership. Vertical integration in the oil and gas industry typically involves a company having upstream, midstream and downstream assets that are linked to each other, in order to capture synergies and margins. Of the large Canadian oilsands firms, Imperial Oil appears to be firmly in this category. Unlike its peers, the company does not appear to have made significant strides in operating cost reductions since 2013, other than increasing production at the Kearl mine to target a cash operating cost of US$20(C$26) per barrel. The company's strategy statement makes no mention of cost management; rather the focus is on delivering high-value products and leveraging technology to achieve higher production volumes and emissions reductions.[31] To deliver this value to its customers, Imperial Oil's oilsands production can be routed to the Strathcona refinery, allowing them to recover some downside when commodity prices are low. While the company's oilsands segment posted losses between 2015 and 2017, vertical integration allowed the downstream segment to capture profits of C$5.38 billion during the same time.

Combined Strategy

While the other major players are focusing on either cost leadership or vertical integration, Husky Energy and Suncor Energy are taking a combined approach, for different reasons. Similar to Imperial Oil, Suncor Energy is a fully integrated company. The company's majority share in Syncrude has allowed it to achieve an almost even balance between bitumen, sour SCO and sweet SCO in its production profile. Combined with its vast midstream and downstream network, it is likely the most integrated oilsands company in Canada. At the same time, Suncor has made also reducing costs at its mining and in-situ facilities a priority, whether through operational efficiencies or the deployment of technology. Husky has placed just as much focus on operational excellence, reducing cash costs by 25 per cent between 2015 and 2017. Although Husky participates in the full oilsands value chain, there is a relative disjoint between its upstream and downstream operations. This is likely the driver behind its parallel cost reduction efforts, as high transportation costs[32] suggest that the company is unable to capture the refining margins that peers like Suncor and Imperial Oil can.

4. 2018: An Encapsulation of Opportunities & Threats

The growth in oilsands production relative to pipeline capacity highlights the need for more transportation options. Although the country has rail capacity of up to 1 mb/d, rail transportation costs twice as much as pipeline transportation and is considered less safe. The commissioning of Enbridge's Line 3 in 2020 is expected to ease some of the bottlenecks by adding about 0.38 mb/d of additional shipping capacity to the US Midwest. Presently, Canadian producers are leaving up to

[31] Imperial Oil. "Imperial Investor Day Presentation." *Imperial Oil.* November 7, 2018. https://cdn.imperialoil.ca/~/media/imperial/files/company/ir/speeches/2018_investor_day_presentation.pdf (accessed February 8, 2019).

[32] Husky Value Chain presentation in the 2018 Husky Annual Report, Page 7

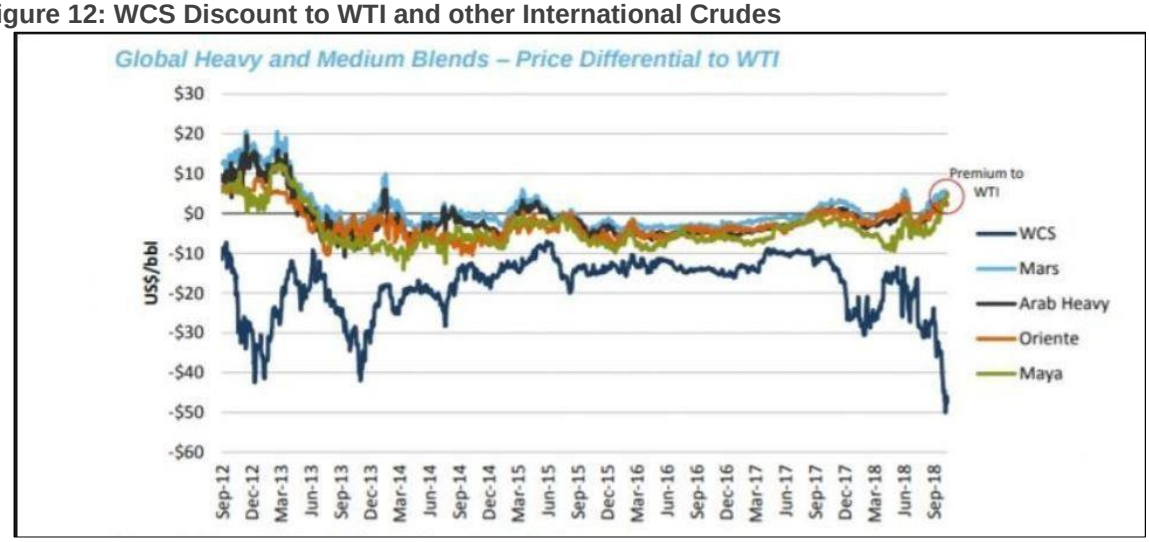
US$10 per barrel on the table when shipping by rail compared to pipelines. Table 2 provides a closer look at WTI/WCS price ratios since 2009.

Table 2: WTI/WCS Price Ratios from 2009 - 2018[33]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
WTI/WCS Price Ratio	1.19	1.21	1.22	1.29	1.35	1.26	1.38	1.47	1.31	1.69

With increasing production from the industry and no new pipelines, a crisis point was reached in the fall of 2018, when the differential between WCS and WTI grew from a steady state of under US$15 to nearly US$50, the widest margin ever recorded,[34] as shown in Figure 12.

Figure 12: WCS Discount to WTI and other International Crudes



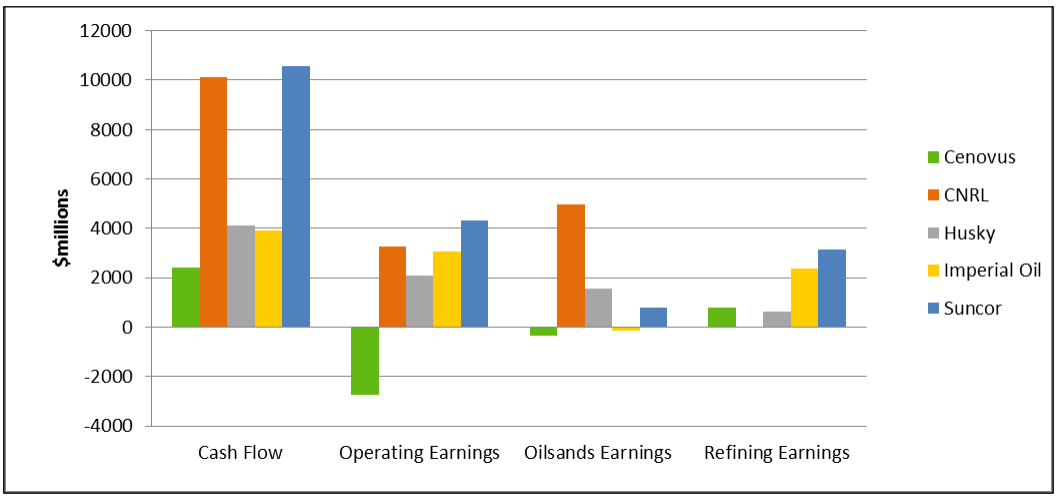
Source: Bloomberg, AltaCorp Capital Inc.

There were concerns about the near-term prospects for oilsands companies – especially those with production profiles dominated by bitumen and thus, heavily dependent on WCS prices. While most oilsands companies reported losses in the fourth quarter of 2018 – CNRL lost C$783 million[35] while Suncor lost C$383 million from its oilsands operations and C$280 million overall – most companies maintained their performance levels from the 2013 to 2017 period across 2018.

Figure 13 summarizes the financial performance of the largest oilsands companies, with all but Cenovus and IOL recording profits from the oilsands segment. Cenovus blamed risk management (i.e. hedging) activities for their losses,[36] suggesting that the segment may have been profitable otherwise. Imperial Oil's vertical integration strategy from the last few years appears to be holding – a willingness to accept losses from the oilsands segment in return for massive profits in the refining business. As a group, these companies recorded over C$31 billion in cash flow, C$10 billion in operating earnings, and crucially, C$6.8 billion in oilsands earnings.

[33] Author calculation based on data from multiple sources (corporate annual reports, NEB, Government of Alberta)
[34] Aliakbari, Elmira, and Ashley Stedman. "Dearth of pipeline capacity drives Canada/U.S. oil price differential to widest point on record." *The Fraser Institute.* October 3, 2018. https://www.fraserinstitute.org/blogs/dearth-of-pipeline-capacity-drives-canadaus-oil-price-differential-to-widest-point-on-record (accessed January 26, 2019).
[35] Data compiled from analysis of fourth-quarter 2018 results released by Canadian Natural Resources Limited, Suncor Energy and various media reports.
[36] Explanation provided in the 2018 Cenovus Annual Report.

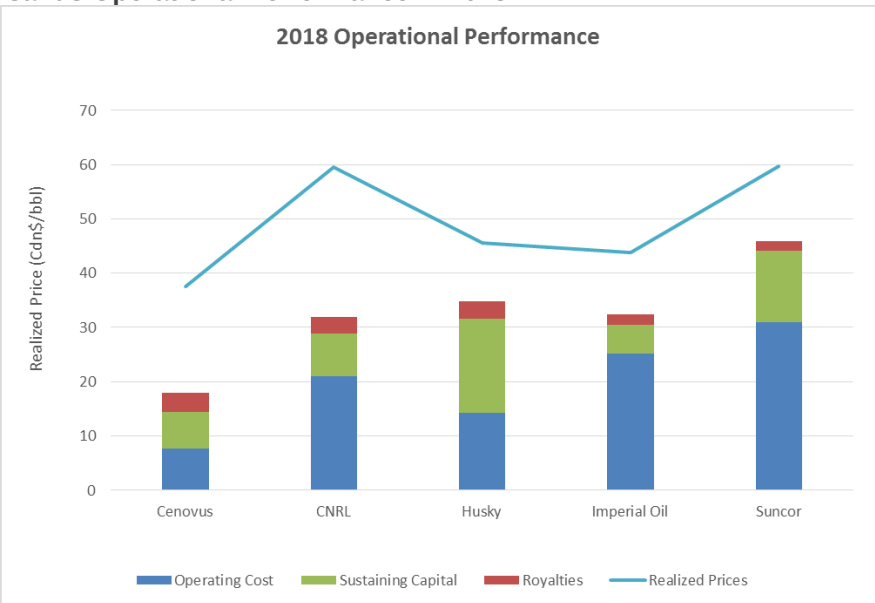
Figure 13: Oilsands Financial Performance in 2018



Source: Corporate Annual Reports

On the operational side, all the analyzed companies realized positive netbacks from oilsands operations in 2018, averaging C$16.60 per barrel, as shown in Figure 14. While these netbacks do not translate directly into net profits – amortization, depreciation and development costs are not included – they are a sign of how well the operating areas returned cash to the business. It's also important to note that these operating costs include carbon taxes, under the Climate Action Plan introduced by the Alberta government in 2015, and implemented as of 2018. While there is some uncertainty about climate policy development and implementation, most producers are factoring these costs into their operations. Suncor, for example, builds in an emissions cost of C$0.70 per barrel into its long-range forecasts.[37]

Figure 14: Oilsands Operational Performance in 2018



Source: Corporate Annual Reports

[37] Suncor Energy Inc. *Carbon policy and regulation.* 2019. https://sustainability.suncor.com/en/climate-change/carbon-policy-and-regulation (accessed July 29, 2019).

5. Impact on Forward Strategy

After reviewing the various data, it is quite apparent that reducing operating costs is both the biggest success so far, and remains the biggest opportunity going forward, for oilsands firms. The ability of Canadian producers to debottleneck their operations and take a less conservative approach to major maintenance, while renegotiating contractual terms with suppliers due to their size and scale, provides competitive advantages. In addition, Canadian producers have chosen to defer capital expenditures due to the longer-life nature of their assets. This has given them added flexibility in controlling costs.

Despite realizing the lowest prices of the five largest producers, Cenovus consistently had one of the largest netbacks. On the other hand, despite a strategy that is boldly focused on vertical integration and capturing marginal value on refined products, Imperial Oil was often the least profitable company modeled. While Imperial Oil is more likely to have higher marginal value per barrel as benchmark prices increase, investors may be more likely to reward the fiscal discipline showed by the low-cost producers. It is important to consider that the vertical integration strategy may be sustainable even in a low price environment, as long as firms can convince shareholders that loss-making oilsands segments can be negated by net profits from the holding company. On the flip side, downward price shocks like that seen in the fourth quarter of 2018 are detrimental even to the most cost-conscious producers. The various strategic approaches adopted by oilsands firms, and their implications, are summarized in Table 3.

Table 3: Strategic Models for Oilsands Firms

Strategic Approach	Key Message(s)	Challenge(s)
Cost Leadership	Control the controllables	Upside-limited
	Protect the downside	Downward price shocks
Vertical Integration	Maximize company-wide returns	WTI/WCS differential shrinks in a low price environment
	Less reliant on crude benchmarks	Investors look more towards upstream than downstream
Combined Strategy	Be profitable in all environments	Potential lack of focus
	Efficient operations drives successful integration	Requires more investment

The combined strategy adopted by both Suncor and Husky appears to withstand most of the negative impacts modeled in the sensitivity outlook. That both companies are integrated will give them additional absolute margin on their barrels, even if their oilsands segments report losses. Their focus on lowering costs will also limit the downside to any losses incurred in a low price environment. As a company with significant mining interests, which has expanded aggressively in the last decade through acquisitions (Syncrude) and growth (Fort Hills), the challenge for Suncor will be optimizing these new additions to be as cost-efficient as its base mine and in-situ operations. However, the value that is consistently unlocked from its refining business continues to give Suncor an edge over its peers in total earnings. On the other hand, while Husky has low costs, the lack of pure integration with its refining business limits top end value relative to pure integrated firms like Suncor and Imperial Oil.

CNRL's strategy is currently low-cost, but the company appears to be transitioning to a combined approach as evidenced by its ownership stake in the Scotford upgrader and the Sturgeon refinery. With its large oilsands mines, CNRL will probably never be able to capture the operating costs that non-miners like Husky and Cenovus have been able to achieve, despite the great strides made so far. The industry seems to have arrived at the belief that low prices are here to stay, and as shown, the mining companies have a slight disadvantage. The ability to unlock additional value lies either by further reducing costs or capturing more from the value chain, a direction CNRL appears to be headed in.

While the models presented operating costs and royalties as fairly static, in reality these variables are likely to change if realized prices increase. This is not a significant risk assuming oil prices stay high, but that is far from certain or expected. With the need to continue rewarding shareholders and invest in growth projects, the market expectation is that companies will continue to cut costs in order to remain viable in a low-cost environment. The challenge for oilsands companies will be to sustain or deepen the cuts that have been made, especially as facilities age and require more maintenance.

5.1 Technology: A Strategic Enabler

From a strategic standpoint, technology presents an opportunity for the industry to reduce operating and capital costs even further, while improving environmental performance in the context of the low-carbon transition. Canadian oilsands companies spend over C$1.4 billion annually on clean technologies, the largest by any single sector in Canada.[38] Technologies include enhanced recovery techniques, carbon capture and storage and increased automation/digitalization.

Enhanced oil recovery in the oilsands is being pioneered at most oilsands in-situ facilities, where the vast amounts of steam used in the extraction process contribute to the growing GHG emissions from In-Situ (37.5 MT in 2016 vs. 17.5 MT for mining facilities). Suncor is currently piloting the use of electrical antennae to heat up the reservoir, a process which – if successful – could eliminate gas-fired steam generation at in-situ facilities,[39] significantly cutting down on upstream GHG emissions. This will also have a positive impact on operating costs, with natural gas the single most expensive commodity for in-situ extraction.

The other technology that has long been touted for the oilsands industry is carbon capture and storage (CCS). Research conducted by the Pembina Institute[40] identified and evaluated scenarios under which GHG emissions could be reduced by CCS, with a focus on low-cost carbon capture technologies. Using forecasted rates for both production and emissions out to 2040 provided by the NEB, the researchers determined that emissions from oilsands could be reduced to 35 MT CO_2e per year with 100 per cent CCS penetration. The Shell Canada-operated Quest CCS facility was launched in 2015, and has stored over four million tonnes of oilsands-generated CO_2e at lower than expected costs, demonstrating that the technology is viable.[41]

Automation and digitalization have been gaining in popularity among oilsands companies. Suncor pioneered autonomous haul trucks in its base plant mining operations and will be introducing the fleet to its Fort Hills mine. Other miners – IOL and CNRL – have since followed Suncor's lead,[42] in a bid to improve safety and reduce operating costs. Other initiatives include the use of holographic headgear and virtual reality to map mine and tailings operations for increased accuracy (and lower capital costs associated with mine planning and reclamation). The same technology can also be used to optimize planning and execution of the costly major maintenance turnarounds executed every four to five years at the large upgraders and in-situ facilities.

5.2 Market Access: Roadblocks or Full Steam Ahead?

Pipeline capacity, or market access, is the biggest external threat to the industry. In the fall of 2018, the differential between WTI and WCS widened to its largest ever level, US$43.55, representing a ratio of 8.29. The government of Alberta's decision to intervene in the market and curtail production was welcomed by some as a necessary move to safeguard the Alberta economy. However, for an industry currently struggling to attract attention from investors, it may have sent the wrong message. While realized prices did recover, the fact that these prices have remained relatively stable since the curtailment was partially lifted, suggests that pipeline capacity may not have been the only reason for

[38] Morgan, Geoffrey. 2019. "Innovation Energy: Oilsands step up to take on clean tech challenge." *National Post.* July 4. Accessed July 5, 2019. https://business.financialpost.com/feature/innovation-energy-oilsands-step-up-to-take-on-clean-tech-challenge.

[39] Rassenfoss, S. 2012. "Oil Sands Get Wired - Seeking More Oil, Fewer Emissions." *Society of Petroleum Engineers*, September 1: 10.2118/0912-0034-JPT.

[40] Kilpatrick, Ryan, Adam Goehner, Eli Angen, Matt McCulloch, and Duncan Kenyon. 2014. *CCS Potential in the Oilsands.* Report prepared for Alberta Government, Alberta Innovates, Energy and Environmental Solutions, and Climate Change Emissions Management Corporation, Pembina Institute.

[41] Shell Canada. 2019. Quest CCS Facility Reaches Major Milestone: Captures And Stores Four Million Tonnes of CO2. May 23. Accessed July 30, 2019. https://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2019/quest-ccs-facility-reaches-major-milestone.html.

[42] McDermott, Vincent. 2018. "Imperial plans deployment of seven automated trucks by year's end, CNRL to start pilot in 2019." *Fort McMurray Today.* July 31. Accessed July 30, 2019. https://www.fortmcmurraytoday.com/news/local-news/imperial-plans-deployment-of-seven-automated-trucks-by-years-end-cnrl-to-start-pilot-in-2019.

the differential.[43] As a result of these pipeline issues, companies like Suncor and CNRL have stated that they will not commission any new projects until pipeline capacity is increased. The lack of growth investment is not as detrimental to oilsands as it is for conventional or LTO fields, but it does create uncertainty about the industry's prospects going forward. The commissioning of Enbridge's Line 3, and the potential to build the TransMountain line to the Pacific Coast, will ease the concerns in this direction. Certainly, continued growth of the industry will require these two pipelines to be built at a minimum, or oilsands companies to be more comfortable with lower realized prices relative to other benchmarks.

6. Conclusion

The oilsands remains a financially viable industry, with major companies in the sector remaining profitable even during the recent oil price collapse. Strategic models that appear the most resilient are either cost leadership or a combined approach of cost leadership and vertical integration. While pure vertical integration may be viable from an enterprise perspective, in a low-price environment it risks showcasing the company's oilsands segment as a loss-making business unit, a prospect that is unattractive to investors.

Most oilsands companies are publicly stating that they can break even at a WTI price of US$45 or less. The evidence suggests that if no new growth projects are sanctioned, existing operations – which have long lives – can remain profitable at WTI prices closer to US$35 or lower. For this to happen, variables that have favoured oilsands companies, such as the US$/C$ exchange rate, will likely need to remain at present levels. Even if Enbridge Line 3 is commissioned in 2020 as planned, at least one other pipeline needs to be built to ease current constraints, likely the TransMountain pipeline from Edmonton, Alberta to Vancouver, British Columbia. This pipeline recently received regulatory approval for the second time, after facing significant opposition from environmental groups and politicians in British Columbia. Its construction is not certain by any means.

In addition, the impact of the Alberta government's cap of 100MT on oilsands emissions is yet to be fully understood. The technological costs required to stay under that emissions cap (and still pay for any greenhouse gases emitted by operations) could exceed the values modeled for this analysis. Inefficient producers lacking the scale and capital heft to explore such technologies – carbon sequestration, solvent-heating or others – could find themselves out of business.

Despite the challenges and chaos of the last five years, oilsands firms have shown a remarkable resiliency and desire to survive. Resolving the pipeline bottleneck without the need for frequent – or ideally, any – governmental intervention to curtail production is necessary. This will help improve the mid- and long-term viability of oilsands firms, even in a low price environment.

[43] Refinery maintenance in the US Midwest was variously reported as the trigger of falling WCS prices in the early fall of 2018. It is likely that the crude stored during this time flooded the market at the same time as the pipeline constraints worsened in late fall, exacerbating the impact of the latter.

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