



INSTITUT **C.D. HOWE** INSTITUTE

COMMENTARY

NO. 635

Last Barrel Standing? Confronting the Myth of “High-Cost” Canadian Oil Sands Production

Oil sands production is more resilient in the face of potential global demand reductions than is commonly understood. The oil sands sector will continue to weather short-term price dips as long as the expected price doesn't dip persistently below C\$40 per barrel.

Dr. G. Kent Fellows



THE C.D. HOWE INSTITUTE'S COMMITMENT TO QUALITY, INDEPENDENCE AND NONPARTISANSHIP

ABOUT THE AUTHOR

DR. G. KENT FELLOWS
is Assistant Professor,
Department of Economics
and The School of Public
Policy, University of Calgary;
Fellow-in-Residence,
C.D. Howe Institute.

The C.D. Howe Institute's reputation for quality, integrity and nonpartisanship is its chief asset.

Its books, Commentaries and E-Briefs undergo a rigorous two-stage review by internal staff, and by outside academics and independent experts. The Institute publishes only studies that meet its standards for analytical soundness, factual accuracy and policy relevance. It subjects its review and publication process to an annual audit by external experts.

No C.D. Howe Institute publication or statement will endorse any political party, elected official or candidate for elected office. Institute staff and authors provide policy research and commentary on a non-exclusive basis. The Institute does not take corporate positions on policy matters.

As a registered Canadian charity, the C.D. Howe Institute accepts donations to further its mission from individuals, private and public organizations, and charitable foundations. It seeks support from diverse donors to ensure that no individual, organization, region or industry has or appears to have influence on its publications and activities. It accepts no donation that stipulates a predetermined result or otherwise compromises its review processes or inhibits the independence of its staff and authors. A comprehensive conflict-of-interest policy, including disclosure in any written work, applies to its staff and its authors.

COMMENTARY No. 635
December 2022

\$12.00

ISBN 978-1-989483-99-2

ISSN 0824-8001 (print);

ISSN 1703-0765 (online)



Daniel Schwanen
Vice President, Research

THE STUDY IN BRIEF

Canadian and global climate change ambitions are generally associated with a goal of reducing reliance on fossil fuels as a mechanism to reduce carbon emissions. Within this context, the Canadian oil sands have been characterized as “too expensive” to maintain production if global crude oil demand falls, a view that appears regularly in the media and even in government reports. Contrary to this accepted “common sense” narrative, the oil sands are not high cost, especially in a way that matters for the relationship between global demand and domestic production. This report shows that nearly all oil sands producers will continue to produce as long as the prevailing price of Western Canadian Select (WCS) crude oil remains above C\$40 per barrel, whereas conventional (non-oil sands) production will likely require prices above C\$40 per barrel for long-term stability.

This difference in price responsiveness is due to the unique cost structure of oil sands projects. Oil sands projects require substantial up-front capital investments, however; once these investments are in place oil sands projects are able to maintain (or slightly increase) year-to-year production over several years or decades with relatively small marginal costs per barrel. This contrasts with non oil-sands producers where individual well productivity falls much faster over time, in turn necessitating new annual capital investments to maintain production.

The analysis presented in this *Commentary* forms a strong argument that legacy oil sands production is more resilient in the face of potential global demand reductions than is commonly understood. The oil sands sector will also continue to weather short-term price dips as long as the expected price doesn't dip persistently below C\$40 (and even then, some producers will continue to produce at any expected price above the C\$15-C\$20 range). In contrast, non oil-sands producers have shown that they will generally stop or dramatically slow investments in new production at West Texas Intermediate (WTI) prices below US\$45 – roughly equivalent to a WCS price of C\$40, adjusting for the exchange rate and quality and transportation differences between WCS and WTI.

The likely durability of oil sands production in a low-price environment means we cannot rely on potential global demand reductions to reduce Canada's emissions footprint through changes in the quantity of production. Emissions reductions in the oil sands will have to rely on reductions in emissions intensity or some policy that expropriates assets or otherwise enforces reductions in production. The federal oil and gas emissions cap, which aims to reduce emissions by 31 percent below 2005 levels in 2030, might end up an example of the latter, depending on how it is implemented. But if emissions reductions occur through output cutbacks, Canada will forgo the significant economic potential of continued production from legacy oil sands assets.

Policy Area: Energy and Natural Resources.

Related Topics: Environmental Policies; Efficiency and Productivity.

To cite this document: Dr. Fellows, G. Kent. 2022. *Last Barrel Standing? Confronting the Myth of “High-Cost” Canadian Oil Sands Production*. Commentary 635. Toronto: C.D. Howe Institute.

C.D. Howe Institute Commentary© is a periodic analysis of, and commentary on, current public policy issues. Barry Norris and James Fleming edited the manuscript; Yang Zhao prepared it for publication. As with all Institute publications, the views expressed here are those of the author and do not necessarily reflect the opinions of the Institute's members or Board of Directors. Quotation with appropriate credit is permissible.

To order this publication please contact: the C.D. Howe Institute, 67 Yonge St., Suite 300, Toronto, Ontario M5E 1J8. The full text of this publication is also available on the Institute's website at www.cdhowe.org.

Most energy policy in Canada is now framed in terms of the “transition to a clean growth economy.” This transition is predicated on the national goal of economy-wide carbon dioxide equivalent (CO_{2e})¹ emissions reductions of 40 percent below 2005 levels by 2030 and net-zero emissions by 2050 (Canada 2022a).

The oil and gas sectors account for nearly 21 percent of Canada’s total industrial and household emissions (author’s calculations; Statistics Canada 2019). Given the sectors’ significance, the federal government has indicated that oil and gas have “a critical role to play in meeting the country’s climate objectives” (Canada 2022b). This is placed within the context of broader global efforts to reduce emissions, and in so doing to reduce reliance on fossil fuel consumption (IPCC 2022).

Much of the public discourse on Canadian oil and gas – specifically, on oil sands production – has characterized domestic production as “high cost” and “uncompetitive” in a future with reduced fossil fuel demand. Most of the oil sands bitumen production is exported, either directly or following domestic processing. The logic then runs that, as Canada and its international trade partners begin to decarbonize, substituting away from crude oil as an energy source, Canada’s own production will quickly become uncompetitive and will decline.

Various articles have characterized oil sands production as “too expensive” to maintain production as demand falls (*Star Tribune* 2019),

“high-cost” (Dawson 2015), “some of the world’s most expensive crude” (Rubin 2015) and “more expensive to produce than in other jurisdictions” (Riley 2020). The ultimate implication of this line of thought is perhaps best articulated by sources such as Vice News, in this quotation from a 2017 article titled “Here’s How Canada’s Oil Sands Could Collapse by 2030”: “The global oil industry could be on the brink of a rapid and irreversible decline. If and when it begins, Canada’s oil sands would be one of the first major casualties” (Dembicki 2017). Multiple reports by research institutes and governments, including a report by the Senate of Canada (Canada 2018), also casually reference the oil sands as “high cost.” This characterization has been adopted almost as “common knowledge,” with little or no contemporary analysis to support it (see, for example, Jaffe 2017; Johnson, Kralovic, and Romaniuk 2016; Millington 2016; Rubin 2016).

The primary goal of this *Commentary* is to dispel this myth. Contrary to this pernicious narrative, the oil sands are not high cost, especially in a way that matters for the relationship between global demand and domestic production. As explained

The author thanks Charles DeLand, Daniel Schwanen, Mawakina Balafe, Kevin Birn, Ben Brunnen, Dave Collyer, Jan Gorski, Rory Johnson, Michael Morgan, Laurie Pushor, Robbie Rolfé and Robert Skinner, as well as anonymous reviewers for their assistance and helpful comments on an earlier draft. The author retains responsibility for any errors and the views expressed.

1 Carbon dioxide equivalents are based on the global warming potential of CO₂ and other greenhouse gases such as methane.

Key Concept Explainer

Oil Sands Production, By Type:

Mining: When oil sands bitumen is found near the surface, this implies the use of surface mining techniques. Earth-moving equipment is employed to dig out the oil sand, which is then transported to a processing facility by dump truck.

In Situ: When the bitumen deposits are found at greater depths, in situ methods are employed. These generally take the form of either *steam-assisted gravity drainage* (SAGD) or *cyclic steam stimulation* (CSS) techniques. Both techniques use high-temperature steam to heat the bitumen, thus reducing its viscosity. SAGD employs the use of two horizontal well bores: an upper bore for steam injection and a lower bore to collect the heated bitumen and bring it to the surface. CSS is similar but uses only one bore that cycles between steam injection (to heat the reservoir) and bitumen production phases.

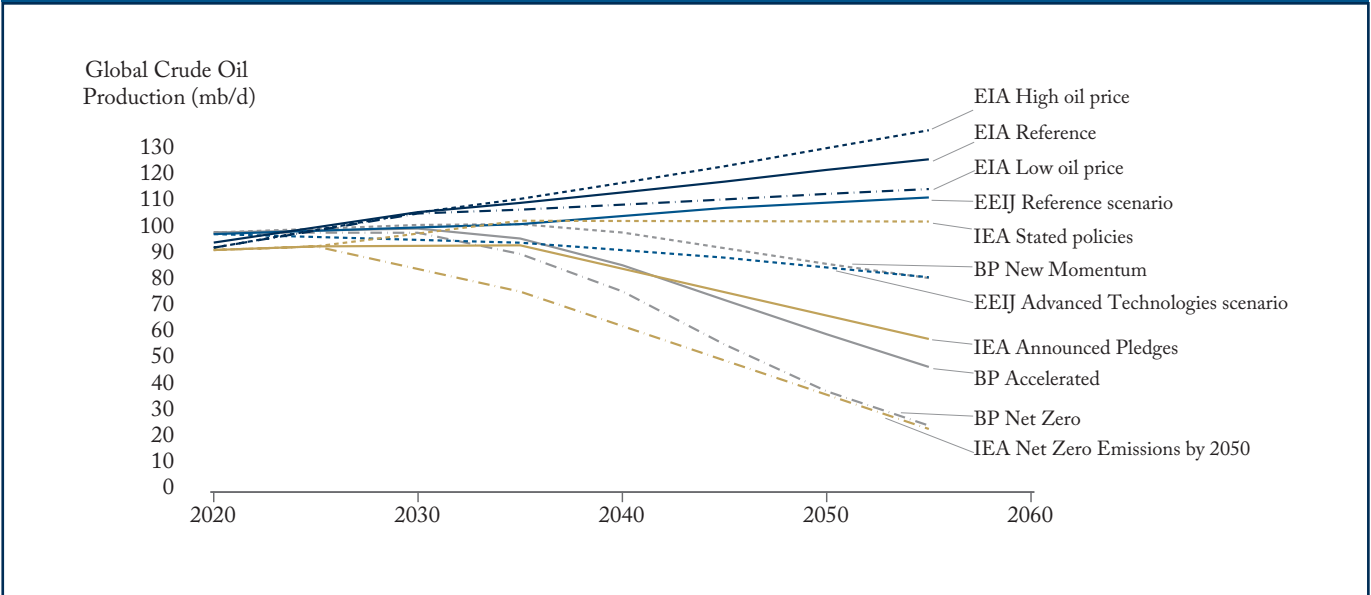
below, the domestic hub price needed to support continued oil sands production is in many cases well below \$40 per barrel, whereas conventional (non-oil sands) North American producers likely require prices above \$40 per barrel for long-term stability in production. In fact, it is possible that we will see production declines from large international state-owned oil producers – specifically, coordinated reductions by members of the Organization of the Petroleum Exporting Countries (OPEC) – before we see reductions in existing oil sands production.

The distinction between oil sands production and conventional production is related to the geology of the oil deposits, the physical properties of the oil (or bitumen) deposits and the method of oil extraction. Canada's oil sands are a somewhat special resource globally. Although there are similar bitumen deposits in other countries – notably, Venezuela, the United States and Russia – Canada's are the largest and most developed. Canada is also the only significant crude oil producer and exporter where the majority of the production is oil sands rather than conventional. Oil sands bitumen is highly viscous in its natural state, once cooled to ambient above-ground temperature, its viscosity resembles

that of smooth peanut butter. Conventional production implies the recovery of a low-viscosity crude oil from a conventional oil well bore hole. A well is drilled, and the resulting bitumen is brought to the surface. Oil sands production is different, since bitumen, in contrast to lighter forms of crude oil, is too viscous to bring to the surface using conventional methods (see Key Concept Explainer).

Because oil sands production requires earth-moving equipment and a processing facility (in the case of a mine) or a steam source (in the case of in situ), the cost structures for oil sands are very different from those for conventional production. Specifically, oil sands production requires a substantial up-front capital investment (in a mine or in situ facility) compared to conventional production, which requires only investment in an oil well. This, in turn, has implications for the emissions footprint of the sector. Oil sands production historically has been characterized as having higher emissions per barrel than more conventional sources. However, the emissions intensities of oil sands producers are highly variable (Sleep et al. 2018), and the effect of Canada's emissions pricing policies on the sector has not

Figure 1: Global Crude Oil Production Scenarios and Projections, 2020–50



Sources: BP 2022; IEA 2022; IEEJ 2021; USEIA 2021.

been uniformly negative on the profitability of individual oil sands projects. Furthermore, although it might be intuitive to conclude that the required up-front capital investment in an oil sands project implies a meaningfully higher cost than conventional producers, this assumption is not correct, particularly for legacy producers (even ones considering marginal expansion).

CRUDE OIL PRODUCTION FORECASTS

Several private sector and government organizations regularly project crude oil production under different potential policy scenarios. Figure 1 shows a selection of these scenarios and projections for global crude oil production to 2050. Each scenario is based on assumptions about the future state of national and international policies along with

assumptions about other market forces. It clearly shows significant and growing disagreement regarding global crude oil volumes out to 2050. Although most of these scenario projections maintain a reasonably narrow bound out to 2030, beyond 2030 there is a split between projections showing modest growth (such as those from the US Energy Information Administration) and those showing significant reductions (such as the BP Accelerated and BP Net Zero scenarios).

In the most ambitious of these projections (the International Energy Agency’s Net Zero Emissions by 2050 and BP’s Net Zero scenarios), total global production and use of crude oil falls to 20 million barrels per day by 2050.² Most projections, however, have the sector shrinking by less than 50 percent between now and 2050. The implication is that these projections continue to leave room for production out to 2050; however, the share of that

2 For context, the oil sands produce roughly 3.5 million barrels per day.

production that oil sands would satisfy depends significantly on regionally specific assumptions and, as argued below, the prevailing price environment, which is likely to favour production from legacy oil sands projects over conventional producers.

HOW TO THINK ABOUT “COSTS PER BARREL”

Prior to discussing “costs per barrel” and how the oil sands compare to conventional production, it is necessary to provide an overview of some economics fundamentals.

It is common to hear economic-related statements including references to “long-run” and “short-run” time frames. These phrases and concepts are thrown around very casually in the public policy space. But despite these casual references, “long term” and “short term” have very specific definitions in the economics orthodoxy. Specifically, the “short run” refers to the longest period in which capital assets are fixed and no capital can be added to (or removed from) the industry in question. The capital investment decision is made up front and fixed for the future. The “long run” is the shortest period in which new capital can be added to (or removed from) the industry in question. The capital investment decisions are made repeatedly as needed for expansion. To summarize: in the short run, capital is fixed; in the long run, capital is variable. Because of this distinction, the way producers (in any sector of the economy) think about costs and production decisions depends on whether they are thinking in the short run or the long run.

In the long run (when capital is variable), production choices are made based on average costs – the total costs of production, including capital costs, divided by total production. If the producer can expand its capital to produce more output at a cost lower than the average price it receives for that output, it should expand output. Conversely, if the producer cannot expand its capital to produce more output at a cost lower than the average price, it should maintain its current capital (or potentially

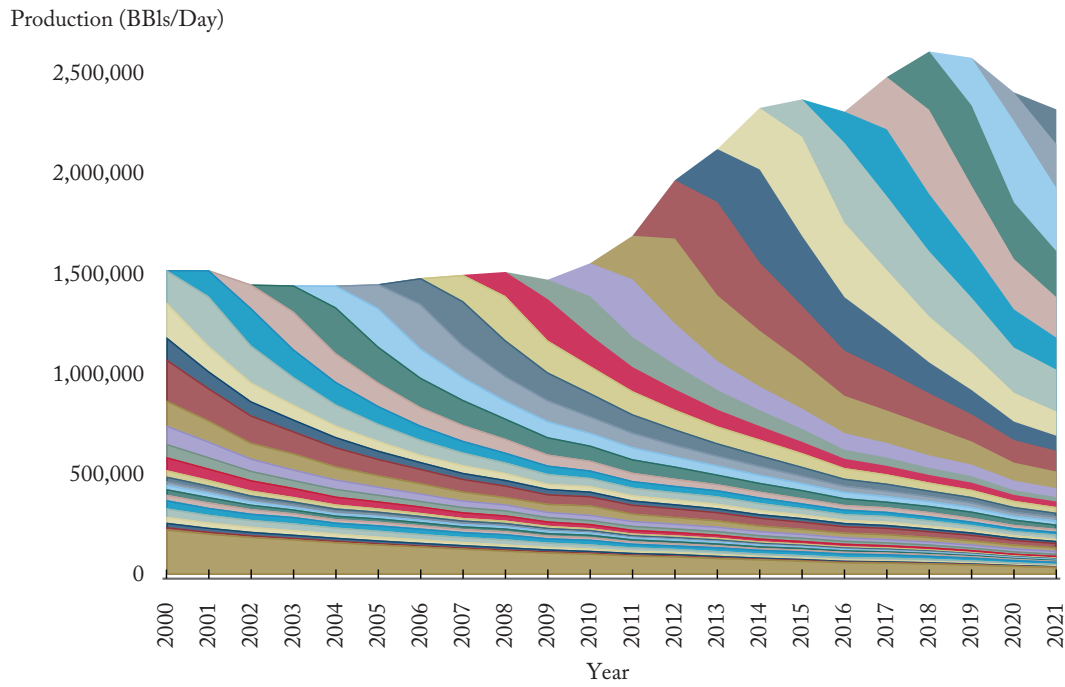
reduce it). In the crude oil sector, this relates to the decision whether to invest in an additional productive oil well (for conventional producers) or in a new oil sands project.

In the short run (when capital is fixed), production choices are based on marginal costs – the direct costs associated with producing one more barrel of output, using the existing fixed capital already in place. If the producer can produce one more unit of output at a cost lower than the market price using its existing capital, it should continue producing (or expand if possible). If the producer cannot produce one more unit of output at a cost lower than the market price using the same capital, it should reduce production (or stop producing). In the crude oil sector, this relates to the decision whether to continue producing from existing wells (conventional) or existing oil sands projects.

The real-world application is, of course, a bit more complex than this, since producers need to contend with future uncertainty. Future prices are not known with certainty and neither are the producers’ input costs, so the calculation needs to factor in expectations on both the price and the cost side of things. Regardless, the short-run versus long-run abstraction remains very useful for understanding the decisions of the different types of crude oil producers. In fact, the concept is paramount to understanding the future role of oil sands production in the context of global crude oil markets and how it differs from conventional production.

Recall that oil sands production requires a substantial up-front capital investment (in an in situ facility or mine), whereas conventional production requires a much smaller up-front capital investment (a well). The capital investments made by both conventional and oil sands producers are sunk, meaning that they cannot be recovered or reversed. But capital investments by conventional producers depreciate (in an economic value sense) much more quickly. This means that, from a textbook microeconomics perspective, conventional producers are perennially operating in the long run.

Figure 2: Western Canadian Sedimentary Basin Sedimentary Basin Conventional Crude Oil Production by Vintage 2000-21



Source: GJL Ltd. 2022. Crude Oil Production Data.

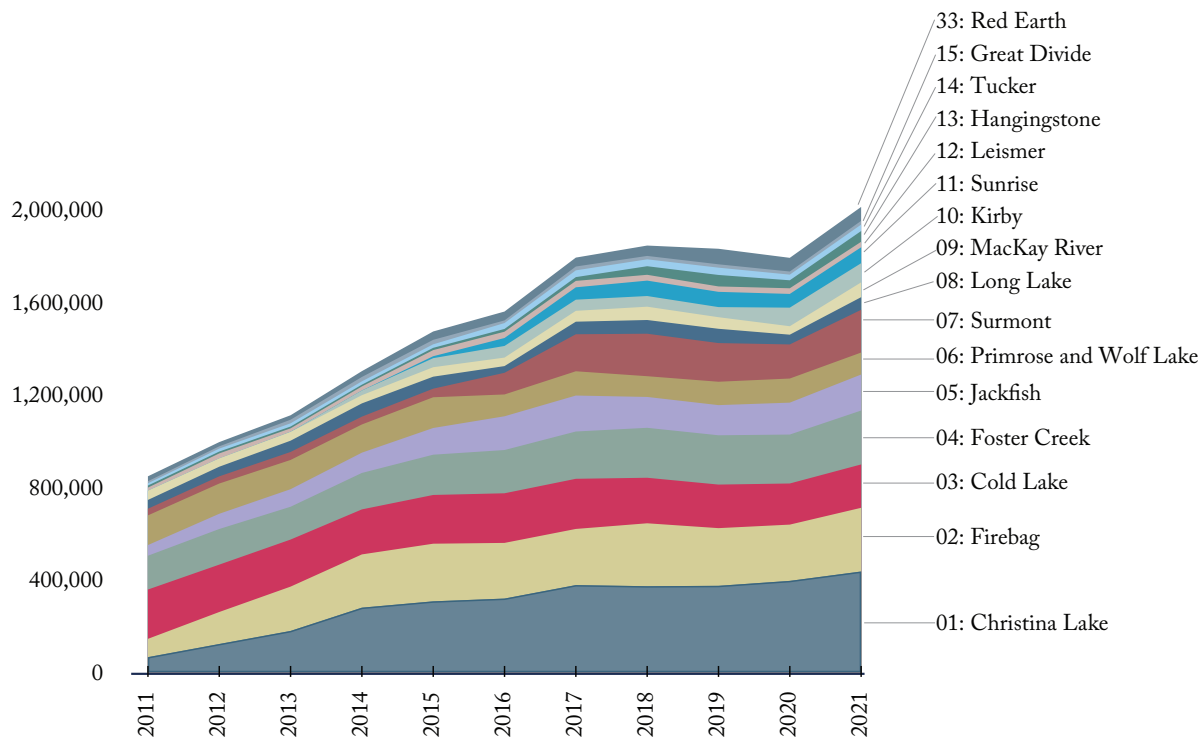
Or, more accurately their “long run” is pretty short, measured in quarters or a few years. In contrast, the sunk capital investments in the oil sands depreciate much more slowly, over decades, and so those producers are continually operating in the short run (particularly when thinking at the project level rather than the firm level).

MAKING PRODUCTION DECISIONS: THE SHORT RUN VERSUS THE LONG RUN

It is not so much the magnitude of the up-front capital investment that matters for the long-run versus short-run distinction, but the implied economic depreciation of that asset. Basically, how quickly the asset loses its productive value to generate output (and associated revenues) dictates the length of the short run.

Figure 2 demonstrates the production by vintage (when the wells first began producing) for conventional Western Canadian sedimentary basin (WCSB) crude oil. For the 2012 vintage, for example, total conventional WCSB crude oil production was just shy of 2 million barrels per day, including approximately 250,000 new barrels per day of production. Following the 2012 contour into 2021, had there been no additional capital investment (that is, no new wells) in the WCSB since 2012, total production would have fallen to 750,000 barrels per day. This decline in the production of aging wells is caused by reductions in well-level productivity over time. Although it is a function of local geology, all conventional production wells share this characteristic decline curve shape, with some oil field regions declining faster and others slower. (Even within the WCSB,

Figure 3: In Situ Crude Bitumen Production, Alberta, 2011–21 (BBLs/day)



Source: Alberta Energy Regulator 2011–21a.

it should be expected that individual wells will have different decline curves, but the average trend among conventional production is what is important.)

Within the industry, the analysis of decline curves is a primary method of forecasting well-level production. In setting their annual drilling budgets, producers need to know how much they want to produce and how much their existing wells will continue to produce. That is,

$$\text{Needed new production} = \text{Total desired production} - \text{Production from existing wells.}$$

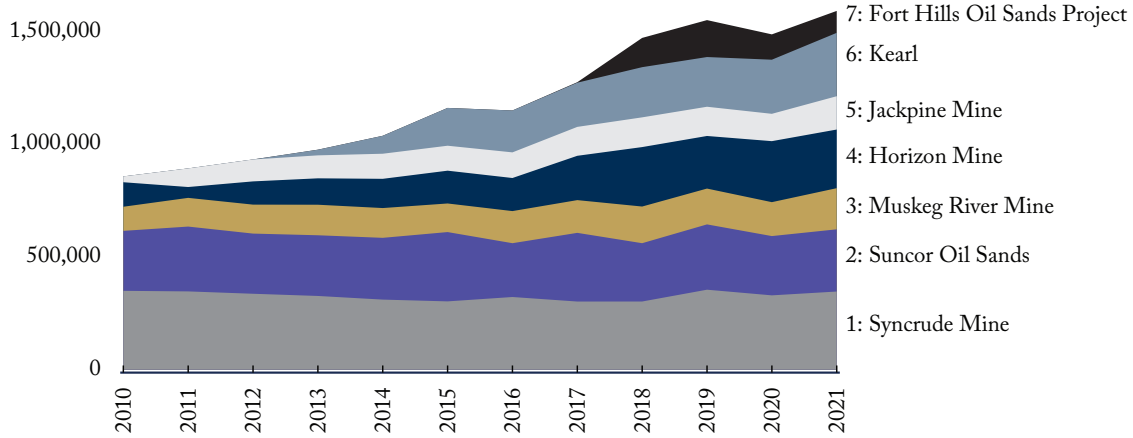
Once a well is drilled, the production decision from that well is essentially binary. It is either run at the optimal (engineered) rate of production or it is

“shut in” (production is suspended). So, the decision on “how much to produce” is effectively a decision on how many wells to drill annually. Therefore, one can characterize conventional producers as operating on long-run principles and, by extension, basing production decisions on average costs rather than on marginal costs.

Contrast the aggregate decline curves in Figure 2 with a similar plot of in situ production by project, as plotted in Figure 3. Although Figure 3 plots production by project, rather than by vintage, the concept is still analogous. Each project has a distinct date for first oil and represents an organized capital investment decision.

The difference between Figure 2 and Figure 3 is striking. Unlike conventional production, in situ production exhibits no annual decline at the project

Figure 4: Oil Sands Mining Crude Bitumen Production, Alberta, 2011–21 (BBLs/day)



Source: Alberta Energy Regulator 2011–21b.

level.³ In fact, many individual projects exhibit increasing production over time. Much of this production pattern reflects differences in geology and the implied necessary production technologies, which involve steam injection. Although some portion of the exhibited increases in production reflects smaller sustaining capital investments, the most substantial capital investment decision (the sanction of the project itself) is not a regular annual decision, but is a long-run (multi-year or multi-decade) production capacity decision.

The situation for oil sands mining is essentially the same as that for in situ production. As shown in Figure 4, production from individual mining projects is essentially stable or increasing over time. Here again, some of that increase in production might be attributable to investments in sustaining

capital. But geology and production technologies are large determinants of these multiyear production patterns. In any case, as with in situ production, the most substantial capital investment decision (the sanction of the mine) is not a regular annual decision, but again reflects a multiyear or multi-decade production capacity decision.

By comparing Figure 2 with Figure 3 and 4, and considering the differences in scale of the required up-front capital investment in oil sands versus conventional production, it is clear that oil sands operators (both mining and in situ) have different capital cycles and cost structures than do conventional producers. To summarize the most important implications of this comparison:

- For the oil sands, the short run is very long;
- fixed and sunk capital costs exhibit very slow

3 Note that individual wells within a project do exhibit some annual decline such that operators need to drill additional sustaining wells to replace production over time. However, that is a relatively small marginal cost, as explained in the discussions of Figure 6 and 7.

economic depreciation with no effective declines in production exhibited at the project level; and

- ultimately, oil sands producers will exhibit an operational focus on marginal costs rather than on average costs at the project level.

In short, *oil sands operators will continue producing as long as the prevailing price is above the marginal cost.*

- For conventional production (both in the WCSB and in all other formations where firms are price takers), the long run is very short;
- fixed and sunk capital costs exhibit much more rapid economic depreciation, with effective decline curves that might vary by well due to local geology, but that reflect more rapid proportional declines than in the oil sands; and
- ultimately, conventional producers will exhibit an operational focus on average costs, rather than on marginal costs when setting annual drilling budgets.

In short, *conventional producers will continue producing as long as the prevailing price is above the average cost.*

That raises the next question: what, if anything, can one say about the marginal costs of oil sands producers and the average costs of conventional producers relative to the prevailing market price for crude oil?

THE MARGINAL COST OF LEGACY OIL SANDS PRODUCERS

Following a recent review of Alberta's royalty system for oil and gas, the Alberta government

began proactively releasing "Alberta Oil Sands Royalty Data" annually. These data comprise all the input data used to calculate royalty payments for each of Alberta's mining and in situ oil sands projects. The data are sufficient to permit the building of a marginal cost curve for the oil sands sector as a whole.

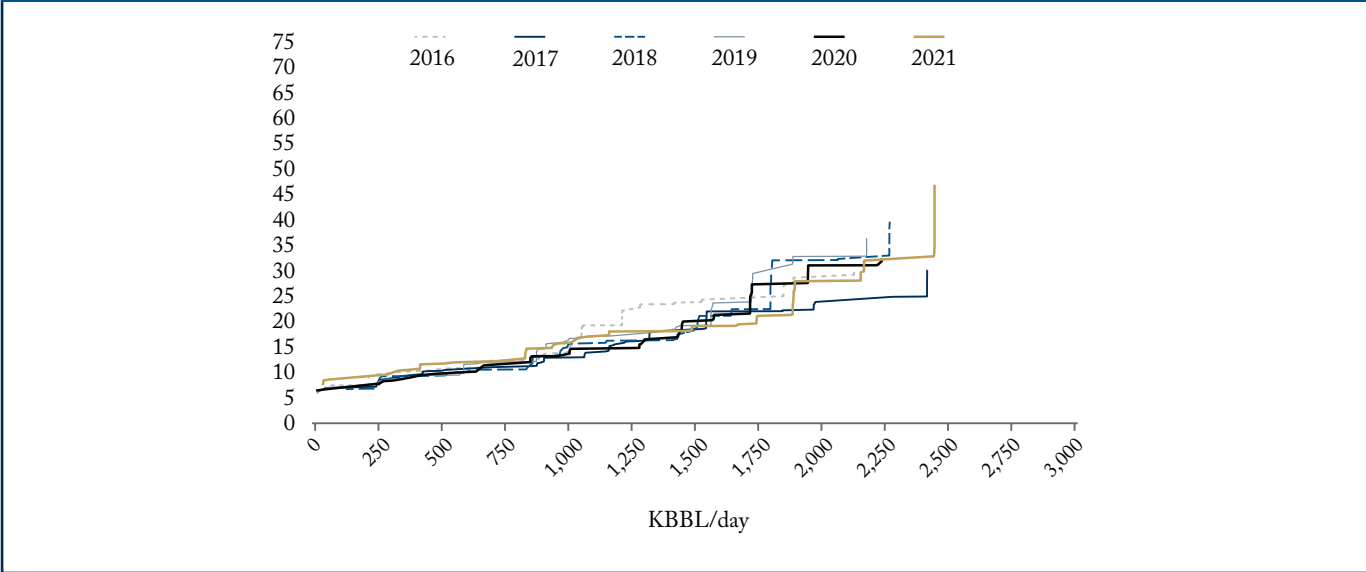
Figure 5 illustrates the marginal cost curves (for the entire sector) in Canadian dollars per barrel of clean crude bitumen,⁴ as calculated at the royalty calculation point.⁵ Each line on the figure represents a different year, calculated using available data from 2016 to 2020. This is essentially a visualization of the raw data. Analogous to the marginal cost of production, average operating costs (netting out capital costs) per barrel are summed, and then each oil sands project's annual production is ordered, from lowest marginal cost to highest. The resulting figure is, in effect, a short-run supply curve for clean crude bitumen as measured at the royalty calculation point.

As Figure 5 illustrates, the marginal cost (the cost to produce an additional barrel) across the oil sands sector ranges from as low as C\$5 per barrel to as high as C\$35 per barrel. In fact, in the most recent year for which data are available, the marginal cost of all oil sands projects was at or below C\$30 per barrel. Despite variation in some of the input costs of oil sands production (most notably natural gas, which is used to produce steam for in situ facilities), there is little year-to-year variation in this marginal cost curve for the

4 Clean crude bitumen is the measure of bitumen once the sand has been removed but before any processing or dilution. Because of its high viscosity compared to lighter conventional crude oil, bitumen is usually either processed (via an "upgrader") or diluted to reduce its viscosity before transportation. However, the royalty calculation and, by extension, the Alberta Oil Sands Royalty Data, focus on the costs and volumes associated with unprocessed and undiluted bitumen. This is because the principle underlying royalty calculation and collection is to ensure that the public gets its share of the value of the raw resource, rather than the value of a processed and/or diluted resource. For more detail on the Alberta royalties principles, see Crisan and Mintz (2016); Dobson (2015); and Shaffer (2016).

5 The royalty calculation point is the physical point at which bitumen leaves the extraction facility and enters either a pipeline transportation system or a processing plant (such as a bitumen upgrader).

Figure 5: Operating Cost, (C\$/BBL, Clean Crude Bitumen, at the Alberta Royalty Calculation Point, 2016–2021



Sources: Alberta 2021a; author’s calculations.

observed years (2016 to 2020). Note that this cost curve represents all of the operating costs associated with production (including existing carbon pricing and all other taxes paid on production).

Because Figure 5 shows the marginal cost of clean crude bitumen at the royalty calculation point, it is an exact realized measure of oil sands project marginal costs. One cannot responsibly compare this marginal cost measure, however, to the prevailing price of crude oil, for a few reasons. First, crude oil prices such as those for Western Canadian Select (WCS), West Texas Intermediate (WTI) and Brent Crude, are set at regional hubs, not at each project or well’s royalty calculation point. Crude oil is worth less at an oil sands project or well head than it is at a regional hub due to the costs of transportation.⁶ Second, the quality of oil

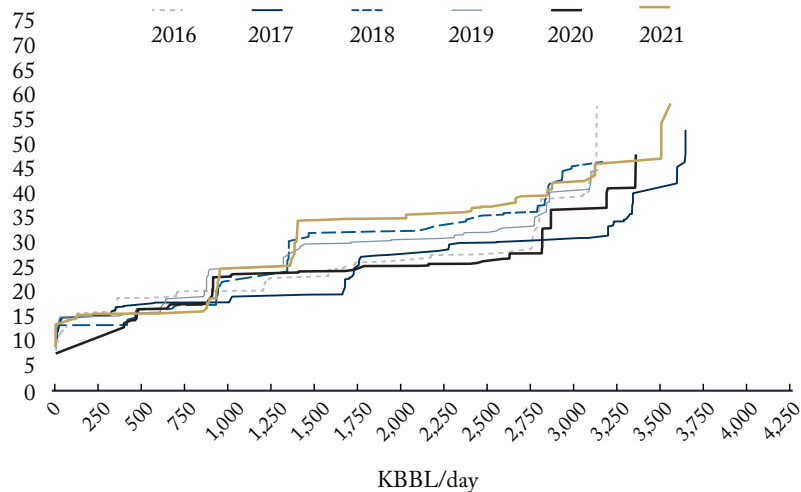
sands bitumen differs from that of the WCS blend (and indeed the WTI and Brent blends).

Crude oil and bitumen are not homogenous products. Bitumen’s high viscosity and other associated chemical differences mean that it is more costly to process into refined products than lighter conventional crude. Processing bitumen also produces a different mix of refined products than lighter crude. Because of this, the (nearly) raw data visualized in Figure 5 cannot be compared directly with benchmark North American oil prices (WTI and WCS).

To address this, the marginal cost measure represented in Figure 5 was modified to include the cost of diluting the bitumen and the cost of transporting the diluted bitumen (dilbit) from the royalty calculation point to the WCS pricing hub

6 As a very simple analogy, consider how much more you are willing to pay to purchase gasoline at a retail outlet compared with having to drive to your nearest oil refinery. Or compare the willingness to pay for groceries at a local grocery store compared with having to drive to a regional wholesale distributor.

Figure 6: Projected Operating and Shipping Costs of Dilbit at Hardisty, Alberta, (C\$/BBL), 2016–2021



Sources: Alberta 2021a; author's calculations.

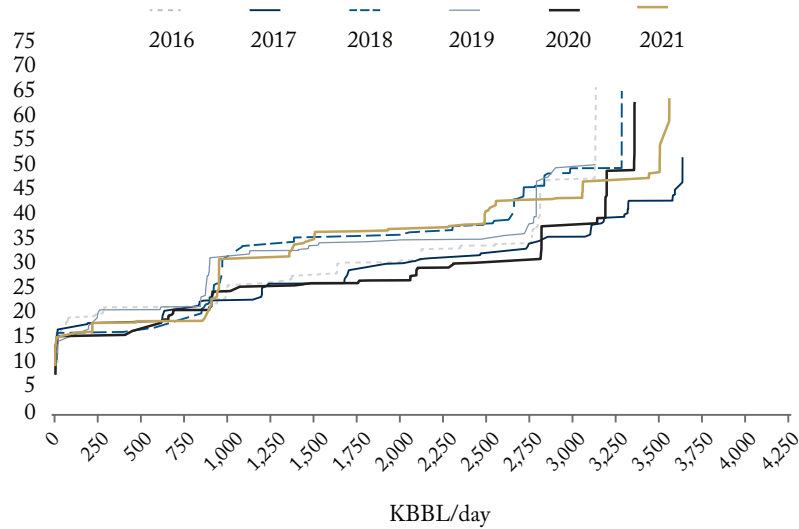
(Hardisty, Alberta). These calculations were done separately for each of the 100+ oil sands projects in Alberta. The adjustment entailed a calculation to determine the quantity of diluent required to dilute the bitumen such that the blended dilbit viscosity matches a required standard based on the viscosity of the WCS blend.⁷ Because each oil sands project produces bitumen with potentially different viscosity, and because oil sands projects in different parts of the province face different transportation costs to move dilbit to the hub, these calculations are idiosyncratic to the projects. (For details of these adjustments, see the Technical Appendix.)

Figure 6 shows the modified marginal cost curve, adjusting for blending requirements to meet the WCS viscosity and to accommodate per barrel

shipping costs to move the diluted bitumen from each oil sands project to the WCS hub at Hardisty, Alberta. These are the same data as in Figure 5, grossed up so that they represent the marginal cost of supplying oil sands dilbit to the Hardisty hub. Comparing Figure 6 to Figure 5, note that, although the shapes of the marginal cost curves look similar, the curve in Figure 6 is both a little higher and more stretched out (showing higher volumes of kilobarrels, or 1,000 barrels per day). This is because the addition of diluent increases both the volume and the cost of production of dilbit relative to clean crude bitumen. The cost of transportation, while less significant, also comes into play.

⁷ Bitumen is generally diluted by adding condensate to it. The exact ratio of condensate to bitumen depends on the initial viscosity of the bitumen (which varies by oil sands project), the viscosity of the condensate added to it (which is known and generally invariant) and the target viscosity of the blended dilbit (which in this case is based on the viscosity of the existing WCS crude oil blend as measured at the Hardisty hub).

Figure 7: Projected Operating, Shipping and Sustaining Capital Costs of Dilbit at Hardisty, Alberta, (C\$/BBL), 2016–2021



Sources: Alberta 2021a; author’s calculations.

But even including these cost additions, which allow for a more direct comparison to the WCS price, the oil sands still exhibit relatively low costs. For 2020 (the last year for which data are available), every barrel of dilbit produced in the oil sands carried a marginal cost below about C\$47 per barrel, with almost all prices per barrel falling at or below C\$40. This is directly analogous to the WCS price. Effectively, if the WCS price is above C\$50 per barrel, all oil sands operators will continue to produce. As alluded to above, when the prevailing price is above the marginal cost, firms will earn a positive return on their capital investment. That is, there will be revenue left over after paying for the variable operating costs. This return might not be sufficient to attract more capital investment to the project (or to a new project), but, as mentioned, the up-front capital investment is sunk and cannot be recovered. So it is in the best interests of oil sands

operators to continue producing as long as the prevailing price is above the marginal cost.

From Figure 6, even if the price falls below C\$47 per barrel, most projects will still have a marginal cost below the prevailing price. In fact, the prevailing price would have to drop below C\$10 per barrel before all oil sands operators would choose to cut production.

As mentioned above, oil sands projects imply a significant initial capital investment, which is then amortized over decades. Although this is by far the most important capital allocation decision an oil sands producer will make, it is not the only one. Due to a combination of physical depreciation of capital assets and the potential to make marginal expansions of the capacity of individual projects, oil sands operators also invest in “sustaining” capital. This represents a complication for the simplifying “short-run” versus “long-run” dichotomy

of orthodox microeconomics. These are capital allocation decisions, but they are not substantial when compared with the initial sunk capital investment. Nevertheless, since sustaining capital does represent an annual operational decision, one can layer it on top of the marginal cost projection shown in Figure 6.

Figure 7 represents the marginal cost associated with supplying dilbit to Hardisty, plus the observed sustaining capital expenditures (per barrel of production) for the oil sands sector. Here again, the implied costs per barrel remain low. The 2020 data show that 3.75 million barrels per day – nearly 95 percent of the sector’s production of 4 million barrels per day – were produced at a marginal cost below C\$40 per barrel, even when sustaining capital costs are included.

Figure 5, 6 and 7 also show that marginal production costs fell between 2016 and 2020 across all three cost measures. This observation is supported by recent industry research suggesting that both capital and operating costs have been falling in the sector (Birn 2019). These data, and the simple projections layered on top, demonstrate the durability of oil sands production in the face of likely future declines in crude oil prices.

THE PREVAILING PRICE ENVIRONMENT

In April 2020, a WTI futures price briefly went negative, meaning that producers and others holding crude oil as a commodity were paying their customers to promise to take oil from them in the future. The monthly average WTI spot price dropped well below C\$20 per barrel, and the WCS price – representing a lower-quality crude oil blend – dropped even lower to well below C\$10 per barrel. Yet, in situ production did not exhibit a notable decline in 2020 (Figure 3) and most

mining producers similarly maintained their 2019 production into 2020 (Figure 4). Why?

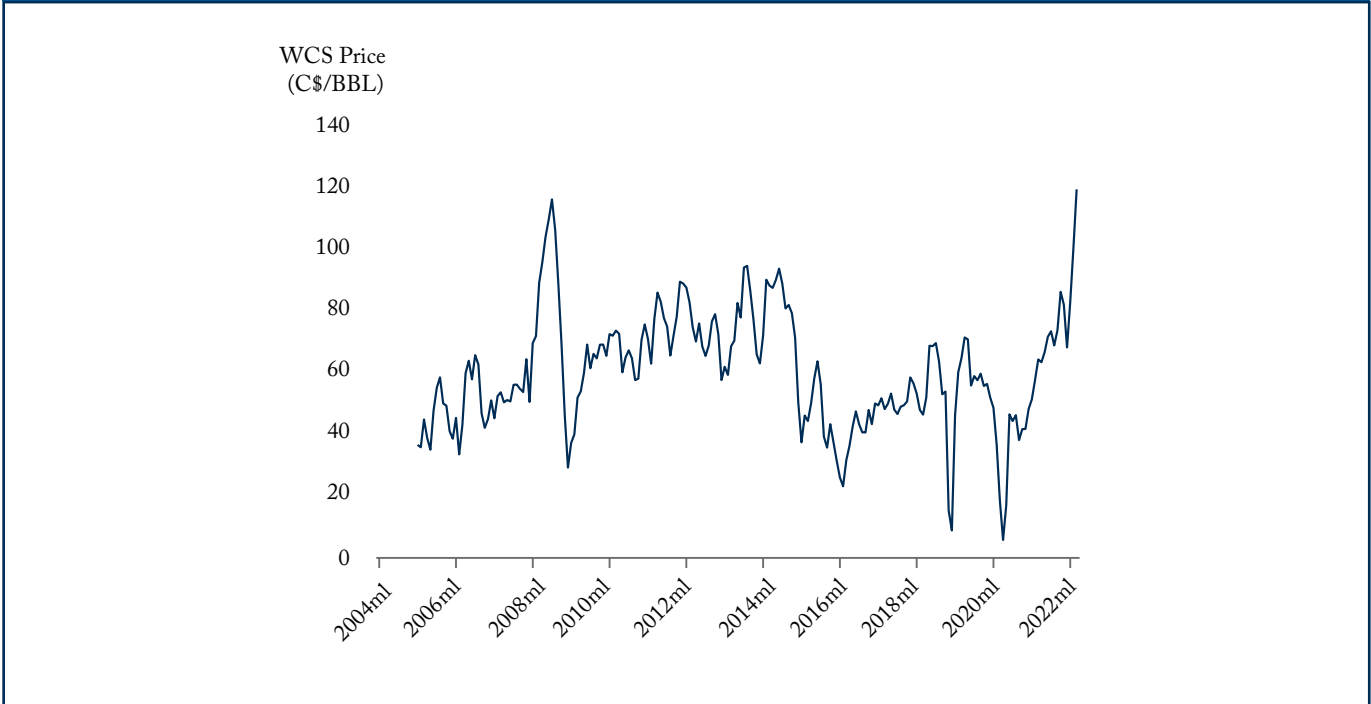
The answer, once again, lies in the timing of strategic production decisions by producers and how one thinks about the prevailing price. Although crude oil spot prices are very visible, even reported as a regular part of business newscasts, current spot and futures prices do not necessarily determine production behavior. When thinking about the “prevailing price,” it is best to consider longer-term dynamics.

Mid- to long-term price expectations matter for production decisions, even in the short run. Figure 8 shows the WCS crude oil price as reported at the Hardisty hub (comparable with the projected marginal cost curves in Figure 6 and 7). Although the price has dropped below the \$40 range a handful of times in the past fifteen years, the only period of sustained prices below \$40 occurred in late 2015 and early 2016, lasting approximately six months.

It is also worth noting that the price troughs in 2019 and 2020 caused the Alberta government to impose mandatory curtailment limits to reduce crude oil production in the province in a successful effort to support higher, more sustainable pricing (Schaufele and Winter 2021). In fact, this is the reason for the 2020 dip in oil sands production, which can be seen in Figure 3 and 4. Left to contend with market forces, absent government intervention, oil sands producers would have produced more during the 2019–20 price dips than they actually did.

Part of the reason for this likelihood is the cost associated with reducing or pausing oil sands production in the short run. Particularly for in situ projects, the production method requires keeping the reservoir heated to ensure bitumen will flow through the geological formations to the production well. It is more costly to reheat a reservoir than to maintain a heated reservoir’s temperature. Letting a

Figure 8: Price of Western Canadian Select Crude Oil (C\$/BBL), Monthly Average at Hardisty, Alberta, 2005–2022



Source: Alberta 2022a.

reservoir cool can also damage it (from a productivity standpoint), reducing the amount of recoverable bitumen from an already-producing reservoir.⁸

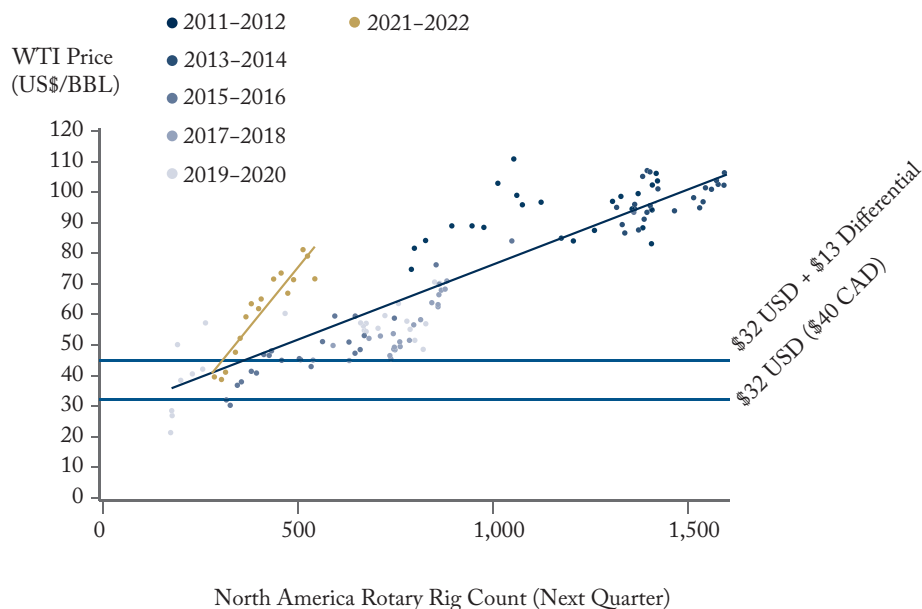
The resulting implication is that oil sands producers are willing and able to continue producing to weather short to moderate periods of depressed spot prices, as long as the expectation is for continued prices above their respective marginal costs, as depicted in Figure 6 (net sustaining capital) or Figure 7 (including sustaining capital).

CONVENTIONAL NORTH AMERICAN CRUDE OIL PRODUCERS' AVERAGE COSTS

The assertions and observations made to this point strongly suggest that oil sands production is durable in periods of low pricing. This is due to the sector's relatively low marginal costs (Figure 7) and the length of the "short-run" period in which production decisions are based on marginal costs rather than on average costs, which is much longer for oil sands

8 This was a point raised during the Fort McMurray–area wildfires in 2016, when a small proportion of in situ oil sands projects was forced to shut production for safety reasons, and there was significant concern among producers about whether production could be restarted before the producing reservoirs cooled too much (see Williams 2016).

Figure 9: North America Rotary Rig Count versus Lagged Price of West Texas Intermediate Crude Oil, 2011–2022



Sources: Baker Hughes 2022; St. Louis Federal Reserve 2022b.

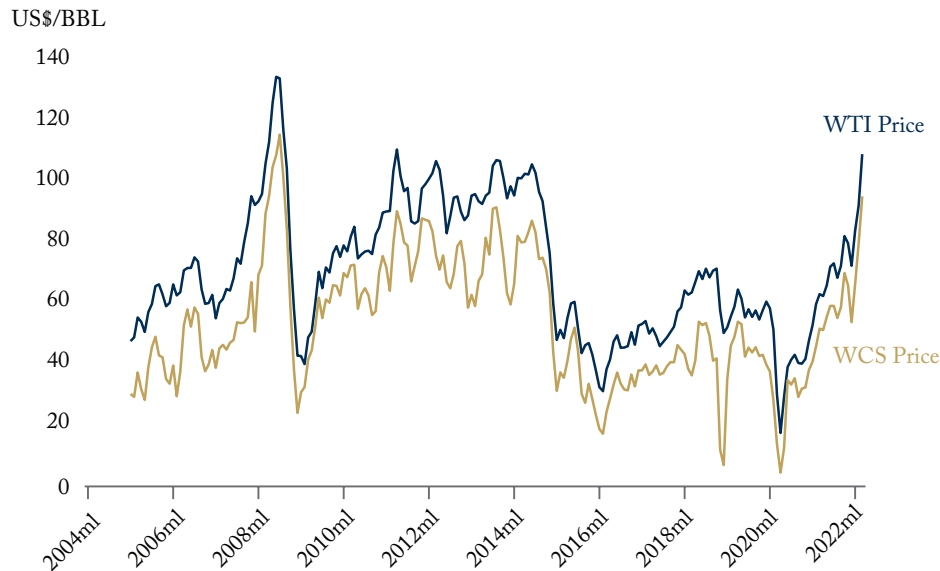
producers (Figure 3 and 4) than for conventional producers (Figure 2). Recall that conventional producers have a much shorter “short run” – using the technical definition of short run as the period in which capital is fixed – and recall also the elementary economics assertion that conventional producers will continue producing as long as the prevailing price is above their average cost.

Given the diversity of geology and the idiosyncrasies of individual conventional producing wells – numbering around 1 million in the United States alone (USEIA 2022) – it is not feasible to produce an average cost curve for conventional producers that would be analogous to the oil sands marginal cost curves presented above. One can gain significant insight into the average costs of conventional production, however, by comparing new investment to prevailing crude oil prices.

The North America Rotary Rig Count (Baker Hughes 2022) serves as a useful proxy for new investment. The count is released weekly and indicates the number of rotary drilling rigs that were actively exploring for or developing (drilling) for oil or natural gas during at least four of the previous seven days. It serves as a measure of investment activity in conventional production, and has long been recognized as a leading indicator of drilling and completion activities related to conventional production.

A simple scatter plot of the Rotary Rig Count against the (lagged) WTI price shows an unmistakable relationship between the two variables, as seen in Figure 9. The figure clearly shows a strong positive relationship, which is expected since conventional producers should expand production when the prevailing price is

Figure 10: Prices of Western Canadian Select and West Texas Intermediate Crude Oil, 2005–2022



Sources: Alberta 2022a; St. Louis Federal Reserve 2022a, 2022b; author's calculations.

above their average cost and otherwise should contract.

The WTI price is recorded at Cushing, Oklahoma, and is denominated in US dollars. To make it comparable to the previous figures (which show the WCS price in Canadian dollars) requires two steps. First is an exchange-rate conversion to deal with the different denominations. Second is to account for the difference in the location of the pricing hubs (Cushing and Hardisty) and the quality of the crude oil blend (light and sweet for WTI, heavier and more sour for WCS).⁹

The quality and location differential between WTI and WCS is highly variable, owing to several factors, including pipeline and refinery capacity –

particularly for refineries tooled to take the heavier WCS blend. It is reasonable, however, to assume a natural differential in the US\$13 range (see, for example, Fellows 2018). Figure 10 shows the two prices over time, with the WCS price converted to US dollars.

To support a more direct comparison between the oil sands producers' marginal cost curves and the average costs of conventional producers (as proxied using the Rotary Rig Count), Figure 9 indicates the equivalent US dollar prices for the C\$40 WCS price, including and excluding the \$13 WCS-to-WTI differential. That is, the upper line indicates a WTI price of US\$45 (\$32 plus the \$13 differential), and is therefore roughly analogous to

9 The heavy versus light distinction is related to the oil's density and viscosity, whereas the sweet versus sour distinction relates to the amount of sulfur impurity present per volume.

a market outcome where WCS is priced at C\$40. Note that, as the WTI price drops below this level, the Rotary Rig Count (indicating new investment in conventional production) drops markedly. This strongly suggests that conventional production in North America is not resilient in a low-price environment.

As the price drops below US\$45 (WTI) or C\$40 (WCS) range, the rig count drops, indicating a significant depression of new investment in conventional production. Another pattern of note is that the relationship between rig counts and the WTI price has strengthened in recent years. Figure 10 includes two lines of best fit through the data, one for the period 2011–20 and another for the past two years of data (December 2021–April 2022). The more recent data show a more muted response to higher WTI prices (the rig count rises by much less than it used to as prices rise). This might indicate more risk aversion by conventional producers.

OPEC AS A PRICE MAKER, NOT A PRICE TAKER

Conventional and oil sands producers in North America are *price takers*. This is evident in the simplified production decision descriptions indicated above:

- oil sands operators will continue producing as long as the prevailing price is above their marginal cost;
- conventional producers will continue producing as long as the prevailing price is above their average cost.

These producers' role as price takers occurs because individual North American firms are too small to

exercise any significant market power. Even the largest crude oil-producing firms in North America cannot unilaterally influence the benchmark crude oil prices (WCS and WTI). As noted earlier, Alberta's crude oil producers were unable to coordinate reductions in production to mitigate the extremely low price environment in 2019 and 2020.¹⁰ This is because individual firms do not control enough production to move the price quantity relationship up or down the crude oil demand curve in a significant way. If a price taker cuts production, the price does not move (or does not move substantially), whereas that firm loses revenue because it is producing (and selling) less crude oil.

In contrast, OPEC represents a cartel of state-owned oil companies¹¹ that exercise substantial productive capacity. The OPEC cartel produces approximately 28 million barrels of crude oil per day and coordinates production across all of its member states in order to influence global oil prices. By comparison, the largest oil sands project (the Syncrude mine) produces less than half a million barrels a day.

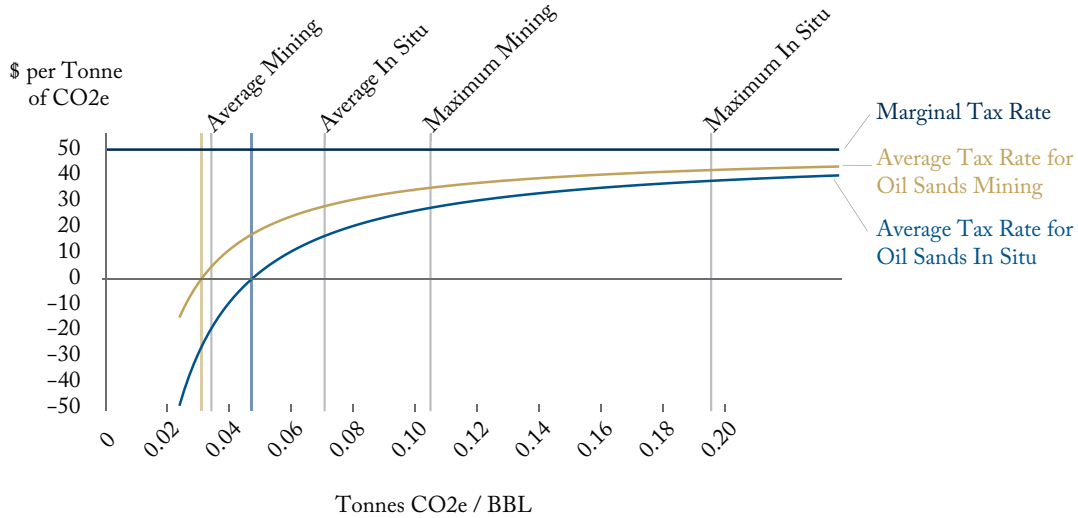
The most appropriate economic model for OPEC is a monopolistic cartel with a competitive fringe. OPEC's market power "arises because there are no other suppliers capable of making up reductions in production to meet the demand of consumers... When OPEC reduces its output and the price of oil rises, non-OPEC countries increase their output, but they cannot replace one for one OPEC's reduction" (Church and Ware 2000, 30).

Considering OPEC as a cartel with a competitive fringe, one can gain some intuition about its expected response to potential reductions in crude oil demand. Any firm or cartel with market

10 It is also important to note that collusion of this sort generally would violate the *Canadian Competition Act* (R.S.C., 1985, c. C-34). So the question of whether producers can collude is not that relevant since they are in fact legally prohibited from colluding to increase prices.

11 OPEC's members are Algeria, Angola, Congo, Ecuador, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela.

Figure 11: Marginal and Projected Average Carbon Tax Rates for Oil Sands Producers



Sources: Author's calculations based on Alberta (2019, 2022b) and Alberta's *Emissions Management and Climate Resilience Act*.

power will respond to a reduction in demand with a proportional reduction in output, in order to preserve a higher price environment. Although the exact response depends on the actions of the competitive fringe (the smaller non-OPEC producers) and the elasticity of demand (the rate at which the quantity of crude oil demanded falls as the price rises), OPEC's exercise of market power will work to preserve higher global prices in the face of demand reductions. Thinking back to the various demand-and-supply projections itemized in Figure 1, it is entirely possible that, in even the most pessimistic scenarios (from the perspective of crude oil producers), prevailing crude oil prices will not fall significantly.

As with the quality and locational comparison of WTI and WCS crude oil, crude oil production by OPEC member states is heterogeneous and exhibits different quality (and different geography) than North American production. All crude oil benchmark prices, however, are integrated to a certain extent. Even though crude oil from different

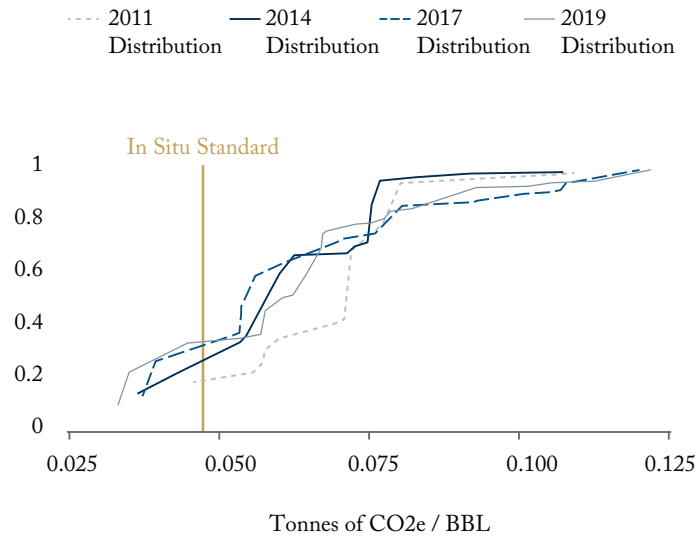
producers is differentiated, there is still a strong degree of substitutability, since, when refined, crude oil from different sources produces a similar basket of refined goods. Because of this, one can conclude that OPEC's continued exercise of market power (if the cartel remains stable) will allow for stable and higher pricing in the face of potential demand declines compared with a global market in which no market power exists.

THE EFFECT OF CANADA'S CARBON-PRICING AND RELATED CLIMATE CHANGE POLICIES

In considering Canada's transition to a low-carbon economy, we know that emissions policies have affected, and will continue to affect, the supply decisions of crude oil producers.

At the federal level, Canada has both a mandated carbon tax on consumers and a large emitters system that places a price on carbon emissions. Alberta has chosen to implement the federal

Figure 12: Cumulative Density of In Situ Producers by Emissions Intensity, 2011–2019



Note: Data are production weighted.

Sources: Author's calculations based on Alberta 2022b.

version of the consumer-facing carbon tax and to introduce a “Technology Innovation and Emissions Reduction Regulation” (TIER) that essentially mirrors the main components of the federal system.

Alberta's TIER regulations (and Canada's federal Output Based Pricing System) are designed to protect emissions-intensive and trade-exposed sectors. Specifically, the regulations are set up to ensure that production in other jurisdictions not subject to carbon pricing is not unfairly advantaged. The cost effects of the TIER regulations are included in the cost curves presented in Figure 5, 6 and 7.

Both TIER and the federal system work by introducing sector-based emissions-intensity targets for CO_{2e} produced per unit of output. Firms with emissions intensities above their industry standard must either pay a carbon tax on excess emissions or purchase carbon credits to put against their excess emissions. Firms with emissions intensities below their industry standard are issued carbon credits

for every tonne of emissions they do not produce relative to the intensity standard.

Because of this, the marginal carbon tax rate per tonne of emissions is basically the same for everyone. All else being equal, if you produce one more tonne of CO_{2e}, you pay C\$50 (at the current tax rate). But the average tax rate depends on the sector-specific intensity standard and the individual firm's emissions intensity in comparison to that standard. A facility that meets the standard exactly will have an average carbon tax rate of zero, while the marginal rate is C\$50 per tonne. A facility that exceeds the standard actually gets an effective net credit (or a negative average tax rate).

Figure 11 shows this relationship between emissions intensities and average and marginal tax rates for oil sands mining and oil sands in situ production. It is worth mentioning that the curves representing the average tax rate might not be a perfect representation of the realized rates. If carbon credits were traded at less than C\$50 per tonne,

the average tax rate would be closer to zero (lower for firms above the intensity standard and higher for firms below it). Figure 11, however, gives some important intuition on the nature and range of the average carbon costs faced by oil sands producers.

Going one step further, it appears that a significant proportion of in situ oil sands projects exhibits emissions intensities below the industry standard. Figure 12 depicts the production-weighted cumulative density of in situ producers by emissions intensity. From the figure, approximately 30 percent of in situ sands producers are likely facing a zero or negative average carbon tax rate. These firms still have a strong incentive to reduce their emissions since they can earn C\$50 per tonne (or the market rate for carbon credits, which might be less than C\$50 per tonne) for every additional reduction in their emissions intensity.

The federal government and presumably the Alberta provincial government are planning to review and potentially reduce emissions standards for all sectors. If these standards drop, average tax rates will increase, but emissions intensities could continue to fall as well. The federal government has also recently announced its intention to introduce an oil and gas sector emissions cap that would reduce emissions by 31 percent below 2005 levels in 2030 (Canada 2022b). This cap could introduce more costs into oil sands production, but it is currently unclear what form this emissions cap will take and how it will be implemented.

The long-term cost of Canada's carbon-pricing system is still to be determined, but it likely will remain less than \$50 per tonne on average, with ongoing effects on the industry. For some producers, costs will increase and, if the regulations are successful, emissions intensities (and overall sector emissions) should fall. But currently enacted policies are unlikely to imply significant reductions in oil sands production unless there are radical policy changes.

CONCLUSION

The analysis presented in this Commentary forms a strong and compelling argument that legacy oil sands production is more resilient in the face of potential global demand reductions than is commonly understood. Nearly all oil sands producers will continue to produce and potentially marginally to expand as long as the prevailing price of Western Canadian Select crude oil remains above C\$40 per barrel. The majority will continue to produce as long as the prevailing price is above the C\$25–\$30 range, and some will continue to produce at prices as low as C\$15–\$20. The oil sands sector will also continue to weather short-term price dips as long as the expectation is for longer-term pricing trends in the aforementioned ranges. In contrast, conventional producers largely will stop investing in new production at West Texas Intermediate prices below US\$45 – roughly equivalent to a WCS price of C\$40, adjusting for the exchange rate and quality and transportation differences between WCS and WTI.

OPEC's role in the global crude oil market also means that potential demand reductions will be met with an exercise of market power that will significantly mute any resulting price effects. As such, demand reductions might not (and are unlikely to) result in substantial and prolonged depressed prices as long as OPEC is able to maintain its cartel and resulting market power.

Finally, although there is an open question as to how the recently announced oil and gas emissions cap will affect the viability of legacy oil sands producers, the current carbon-pricing system is a strong incentive to reduce emissions intensity while protecting exports.

The likely durability of oil sands production in a low-price environment means we cannot rely on potential global demand reductions to reduce Canada's emissions footprint through changes in the quantity of production (the extensive margin). Emissions reductions in the oil sands will have

to rely on reductions in emissions intensity or some policy that expropriates assets or otherwise enforces reductions in production. The oil and gas emissions cap might end up an example of the latter, depending on how it is implemented. But if emissions reductions occur on the extensive margin, Canada will forgo the significant economic potential of continued production from oil sands assets.

To quote Canada's current prime minister in 2017, "No country would find 173 billion barrels of oil in the ground and just leave them there."¹² It remains to be seen whether the oil and gas

emissions cap will abide by this attitude or evidence a change in the sentiment of the prime minister and the federal government. But one thing seems clear: market forces will not eliminate legacy oil sands production before other sources. There is a reasonable argument that, if there is a last barrel of oil produced in North America, it will come from an oil sands operator unless government policy decides to actively forgo that economic opportunity.

12 *CBC News*, online at <https://www.cbc.ca/player/play/894872131944>

TECHNICAL APPENDIX

To calculate the projected marginal cost for an oil sands project to produce bitumen to the royalty calculation point (Figure 5) and to dilute the bitumen and ship it to the WCS hub (Figure 6), two measures are needed. One is each project’s specific diluent blending requirements – the ratio of condensate to bitumen such that a project’s dilbit blend would match the density of the WCS blend. The other is a measure of the transportation cost relative to the WCS hub. The calculation in this *Commentary* of these two cost components is informed by the Alberta government’s Bitumen Valuation Methodology (BVM), a set of calculations to produce price projections for bitumen not sold at arm’s length – and therefore with no observable market value. BVM works backwards to produce a price projection at the royalty calculation point based on the Hardisty hub price for the WCS blend. Here, the same methodology is employed in reverse, to project the cost to dilute and move bitumen from the royalty calculation point to the WCS hub with sufficient dilution to match the density of the WCS blend.

Previous studies have demonstrated that the BVM methodology might substantially overvalue bitumen that is not sold at arm’s length (Balyk, Dachis, and DeLand 2021; Fellows 2021). A similar bias might be applied here, in that the imputed adjustment for transportation could be in error. It is not clear, however, in which direction this bias would affect the transportation costs included in Figure 6 and 7, since the direction of the BVM bias identified in prior work can be identified only for non-arm’s-length sales.

Determining the density ratio of condensate to bitumen for a given volume of dilbit requires an iterative process following the American Petroleum Institute’s “Calculation of Petroleum Quantities” (API 2007). The iterative process is required to account for volumetric shrinkage that occurs as part of the blending process.¹³

The first step is to calculate the condensate that would be required to dilute an existing blend (which in the first iteration is 100 percent raw bitumen) such that the dilbit density would match the density of the monthly WCS blend, ignoring shrinkage. This is done as per equation (1):

$$b_i = \frac{D_{i-1} - D_{WCS}}{D_{WCS} - D_d}, \quad (1)$$

where b_i is the bitumen addition calculation for iteration $i \in \{1,5\}$; D_{WCS} is the monthly density of the WCS blend; D_d is the monthly density of condensate; and D_i is the density of the candidate blend for the iteration (note that D_0 implies the density for the project’s raw bitumen output).

The shrinkage is then accounted as in equation (2). Since the total mass of the dilbit blend is preserved, the associated shrinkage implies a higher density. As such, this process is iterated by calculating additional condensate requirements in each iteration. Formally:

$$Shrinkage_i = (2.69 \times 10^4) \left(\left[100 - \left(100 \frac{b_i}{1+b_i} \right) \right] \left(\frac{1}{D_d} - \frac{1}{D_{i-1}} \right) \right)^{2.28}, \quad (2)$$

13 Note that a form of this calculation is built into the Alberta government’s Royalty Calculation Excel Workbook (Alberta 2021b).

where $Shrinkage_i$ is the volumetric shrinkage in the candidate blend in iteration i .

Finally, one can solve for the density of the candidate blend for iteration i , to be used in the next iteration $i + 1$ (equation 3):

$$D_i = \frac{D_{i-1} - D_{WCS}}{1 + b_i - Shrinkage_i} . \quad (3)$$

Starting with $i = 1$, the entire iterative process involves solving equations (1), (2) and (3) in order, then iterating to $i = 2$ and resolving.

By progressing through each iteration, the density of the implied dilbit blend (accounting for shrinkage) will asymptotically approach the target density (the monthly density of the WCS blend). The error quickly falls to an insignificant level. Here, as in the Alberta government's workbook (Alberta 2021b), five iterations are employed.

The total value for b is then

$$b = \sum_{i=1}^5 b_i . \quad (4)$$

Information on monthly condensate and WCS blend densities to inform this calculation is available in Alberta (2021c), and information on the range of bitumen densities produced by oil sands projects is available from Maxxam Analytics (2014). Although these data do not attribute specific densities to specific projects, they do identify densities by field location (Peace River, Athabasca, Cold Lake) and extraction technology (mining, primary, thermal), as indicated in Appendix Table A-1.

Based on the densities in Table A-1, values for b are calculated for each location/extraction technology pair and attributed to individual projects accordingly.

To project the transportation costs from field to hub, one of two methods is used: relying either on publicly available transportation tolls or disaggregating available data to identify the implied transportation charge.

For projects located in the Cold Lake field, the estimate is based on the January 2020 postage stamp toll for the Cold Lake Pipeline System (Inter Pipeline Ltd. 2020): \$0.98 per cubic metre (or about \$0.16 per barrel). For the Peace River field, the estimate is based on the July 2009 toll for the Rainbow Pipe Line (Rainbow Field to Edmonton Hub) (Plains Midstream Canada ULC 2009): \$16.73 per cubic metre (or \$2.66 per barrel). Note that these tolls are per barrel of dilbit, not per barrel of bitumen.

To determine transportation costs for the Athabasca region, the prices calculated using Alberta's BVM are compared directly with the observed field prices for oil sands mines that are consistently subject to BVM pricing. This methodology produces a transportation cost of about \$0.51 per barrel of dilbit.

These per dilbit barrel transportation costs are converted into a per bitumen barrel transportation cost following the methodology in Alberta (2008). Table A-2 summarizes the transportation adjustment assumptions by location and extraction technology. Given that the calculation method is based on production weighted averages, there is some variation in assumed transportation costs even within location/technology pairs. As such, both the range and the average transportation adjustment are presented for each location/technology pair.

Table A1: Assumed Bitumen Density, by Field and Extraction Technology, Alberta

Location	Assumption
	(absolute density at 15°C, kg/m ³)
Athabasca mining	1,010.9
Athabasca primary	980.2
Athabasca thermal	1,012.7
Cold Lake primary	1,004.4
Cold Lake thermal	993.6
Peace River primary	1,001.9

Source: Maxxam Analytics (2014).

Table A2: Assumed Transportation Adjustments: Summary Table (CAD per bbl of clean crude bitumen)

Location	Minimum	Average	Maximum
	(c\$ per barrel of clean crude bitumen)		
Athabasca mining	0.89	0.92	0.93
Athabasca primary	0.75	0.77	0.78
Athabasca thermal	0.90	0.92	0.94
Cold Lake primary	0.25	0.25	0.26
Cold Lake thermal	0.25	0.25	0.26
Peace River primary	4.38	4.50	4.59
Peace River thermal	4.40	4.47	4.55

Source: Author's Calculations

REFERENCES

- Alberta. 2003. *Emissions Management and Climate Resilience Act*.
- . 2008. *Mines and minerals act: Bitumen valuation methodology (ministerial) regulation*.
- . 2019. “Technology Innovation and Emissions Reduction Regulation.” Edmonton. Online at <https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation.aspx#:~:text=The%20Technology%20Innovation%20and%20Emissions%20Reduction%20%28TIER%29%20Regulation,TIER%20applies%20to%20about%2060%25%20of%20Alberta%20emissions>
- . 2021a. “Alberta Oil Sands Royalty Data.” Edmonton. Online at <https://open.alberta.ca/opendata/alberta-oil-sands-royalty-data1>
- . 2021b. “Royalty Calculation Excel Workbook.” Online at <https://open.alberta.ca/opendata/bitumen-valuation-methodology-bvm-model-calculator>
- . 2021c. “Oil Sands Monthly Royalty Rates and BVM Pricing Components (2016–2020).” Edmonton. Online at <https://inform.energy.gov.ab.ca/ILSummaryResults.aspx?Commodity=Oil+Sands&Status=Active&YearFrom=All&YearTo=All&Topic=All&AdvancedSearch=Y&OrgKey=All&OrgName=All>
- . 2022a. “Alberta Economic Dashboard: Oil Prices.” Edmonton. Online at <https://economicdashboard.alberta.ca/OilPrice>
- . 2022b. “Alberta Oil Sands Greenhouse Gas Emission Intensity Analysis.” Edmonton: Alberta Environment and Parks. Online at <https://open.alberta.ca/opendata/alberta-oil-sands-greenhouse-gas-emission-intensity-analysis>
- Alberta Energy Regulator. 2011–21a. “ST53: Alberta In Situ Oil Sands Production Summary.” Edmonton. Online at <https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st53#:~:text=ST53%3A%20Alberta%20In%20Situ%20Oil%20Sands%20Production%20Summary,the%20Peace%20River%2C%20Athabasca%2C%20and%20Cold%20Lake%20areas>
- . 2011–21b. “ST39: Alberta Mineable Oil Sands Plant Statistics Monthly Supplement.” Edmonton. Online at <https://uat.aer.ca/providing-information/data-and-reports/statistical-reports/st39#:~:text=ST39%3A%20Alberta%20Mineable%20Oil%20Sands%20Plant%20Statistics%20Monthly,and%20the%20preceding%20months%20of%20the%20current%20year>
- API (American Petroleum Institute). 2007. “Manual of Petroleum Measurement Standards Chapter 12 – Calculation of Petroleum Quantities.” Washington, DC. Online at <https://standards.globalspec.com/std/1025136/API%20MPMS%2012.3>
- Baker Hughes. 2022. “North America Rotary Rig Count.” Online at <https://rigcount.bakerhughes.com/na-rig-count>
- Balyk, J., B. Dachis, and C. DeLand. 2021. “An Oil Sands Inequity: Alberta’s Outdated Bitumen Valuation Program.” E-Brief 320. Toronto: C.D. Howe Institute, October 7.
- Birn, K. 2019. “Four Years of Change: Oil Sands Cost and Competitiveness in 2018.” Crude Oil Markets Strategic Report. London: IHS Markit.
- BP. 2022. “Energy Outlook.” Online at <https://www.bp.com/en/global/corporate/energy-economics/energy-outlook/oil-demand.html>
- Canada. 2018. Senate. Standing Committee on Energy, the Environment and Natural Resources. “Canada’s Oil and Gas in a Low-Carbon Economy.” Ottawa. Online at https://sencanada.ca/content/sen/committee/421/ENEV/reports/ENEV_OilGas_FINALweb_e.pdf
- . 2022a. “Emissions Reduction Plan.” Ottawa. Online at <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030.html>
- . 2022b. “Oil and Gas Emissions Cap.” Ottawa. Online at <https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/oil-gas-emissions-cap.html>

- Church, J.R., and R. Ware. 2000. *Industrial Organization: A Strategic Approach*. New York: Irwin McGraw Hill.
- Crisan, D., and J. Mintz. 2016. "Alberta's New Royalty Regime Is a Step towards Competitiveness: A 2016 Update." *SPP Research Paper* 9 (35).
- Dawson, C. 2015. "Canadian oil-sands producers struggle." *Wall Street Journal*, August 19. Online at <https://www.wsj.com/articles/oil-sands-producers-struggle-1440017716>
- Dembicki, G. 2017. "Here's how Canada's oil sands could collapse by 2030." *Vice News*, August 14. Online at <https://www.vice.com/en/article/paabxk/heres-how-canadas-oil-sands-could-collapse-by-2030>
- Dobson, S. 2015. "A Primer on Alberta's Oil Sands Royalties." *School of Public Policy Publications* 7 (7). Online at <https://www.policyschool.ca/wp-content/uploads/2016/03/ab-oil-sands-royalties-dobson.pdf>
- Fellows, G.K. 2018. "Energy and Environmental Policy Trends: The Invisible Cost of Pipeline Capacity Constraints." *School of Public Policy Publications* 11. Online at <https://journalhosting.ucalgary.ca/index.php/sppp/article/view/43419>
- . 2021. "A General Model of Bitumen Extraction and Partial Upgrading Economics." Unpublished.
- IEA (International Energy Agency). 2022. "World Energy Outlook 2022 Free Dataset." Paris. Online at <https://www.iea.org/data-and-statistics/data-product/world-energy-outlook-2022-free-dataset>
- IEEJ (Institute of Energy Economics, Japan). 2021. "Outlook 2022 – Challenges toward Carbon Neutrality: Voyage in Uncharted Territory." Tokyo. Online at <https://eneken.ieej.or.jp/en/whatsnew/439.html>
- Inter Pipeline Ltd. 2020. "Petroleum Toll Schedule no. 2110." Online at https://static.interpipeline.com/20210323113029/CLPL_January_2020.pdf
- IPCC (Intergovernmental Panel on Climate Change). 2022. "Mitigation of Climate Change – Summary for Policymakers." Working Group III contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Online at https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_SPM.pdf
- Jaffe, A.M. 2017. "How Does Canada Respond to Stranded Asset Risk?" Calgary: Canadian Global Affairs Institute. Online at https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/energy-resources/How_Does_Canada_Respond_to_Stranded_Asset_Risk.pdf
- Johnson, L., P. Kralovic, and A. Romaniuk. 2016. "Canadian Crude Oil and Natural Gas Production and Supply Costs Outlook (2016–2036)." CERI Study 159. Calgary: Canadian Energy Research Institute. September. Online at https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/energy-resources/CERI_Study_159_Full_Report.pdf
- Maxxam Analytics. 2014. "Alberta Bitumen Assay Program Technical Data Review."
- Millington, D., 2016. "Low crude oil prices and their impact on the Canadian economy." Canadian Energy Research Institute. https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/energy-resources/CERI_Study_156_Full_Report.pdf
- Plains Midstream Canada ULC. 2009. "Tariff no. 69." Online at <https://www.auc.ab.ca/regulatory-documents/ProceedingDocuments/2009/2009-098.pdf>
- Riley, S.J. 2020. "11 things you need to know about the oilsands as Teck abandons plans for Frontier mine." *Narwhal*, February 24. Online at <https://thenarwhal.ca/11-things-you-need-to-know-about-the-oilsands-as-the-frontier-headlines-roll-in/>
- Rubin, J. 2015. "How \$40 oil would impact Canada's provinces." *The Globe and Mail*. <https://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/how-40-oil-would-impact-canadas-provinces/article22288570/>

- . 2016. “The Future of Canada’s Oil Sands in a Decarbonizing Global Economy.” *Policy* (Centre for International Governance Innovation), July–August. Online at <http://policymagazine.ca/pdf/20/PolicyMagazineJulyAugust-2016-Rubin.pdf>
- Schaufele, B., & Winter, J. 2021. “Measuring the Economic Impact of Alberta’s Crude Oil Curtailment Policy.” Ivey Business School Policy Brief. January.
- Shaffer, B. 2016. “Lifting the Hood on Alberta’s Royalty Review.” School of Public Policy Publications 9 (7).
- Sleep, S., I.J. Laurenzi, J.A. Bergerson, and H.L. MacLean. 2018. “Evaluation of Variability in Greenhouse Gas Intensity of Canadian Oil Sands Surface Mining and Upgrading Operations.” *Environmental Science & Technology* 52 (20): 11941–51.
- Star Tribune* (Minneapolis). 2019. “Tar-sands economics don’t add up.” June 5. Online at <https://www.startribune.com/tar-sands-economics-don-t-add-up/510994192/>
- Statistics Canada. 2019. “Physical flow account for greenhouse gas emissions.” Table 38-10-0097-01. Ottawa. Online at <https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=3810009701>
- St. Louis Federal Reserve. 2022a. “Canadian Dollars to U.S. Dollar Spot Exchange Rate.” Online at <https://fred.stlouisfed.org/series/DEXCAUS/>
- . 2022b. “Crude Oil Prices.” Online at <https://fred.stlouisfed.org/series/DCOILWTICO/>
- USEIA (US Energy Information Administration). 2021. “International Energy Outlook 2021.” Washington, DC. Online at https://www.eia.gov/outlooks/ieo/tables_side_xls.php
- . 2022. “U.S. Oil and Natural Gas Wells by Production Rate.” January 13. Washington, DC. Online at [https://www.eia.gov/petroleum/wells/#:~:text=The%20number%20of%20producing%20wells,rig%20activity%20\(Figure%201\)](https://www.eia.gov/petroleum/wells/#:~:text=The%20number%20of%20producing%20wells,rig%20activity%20(Figure%201))
- Williams, N. 2016. “Canada oil sands thermal shutdowns pose risk to delicate reservoirs.” Reuters, May 11. Online at <https://www.reuters.com/article/us-canada-wildfire-thermal-idUKKCN0Y22E4>

NOTES:

RECENT C.D. HOWE INSTITUTE PUBLICATIONS

- December 2022 Wyonch, Rosalie, and Tingting Zhang. *Damage Averted: Estimating the Effects of COVID-19 Vaccines on Hospitalizations, Mortality and Costs in Canada*. C.D. Howe Institute Commentary 634.
- December 2022 Kronick, Jeremy, and Luba Petersen. *Crossed Wires: Does Fiscal and Monetary Policy Coordination Matter?* C.D. Howe Institute Commentary 633.
- November 2022 Laurin, Alexandre, and Nicholas Dahir. *Softening the Bite: The Impact of Benefit Clawbacks on Low-Income Families and How to Reduce It*. C.D. Howe Institute Commentary 632.
- November 2022 Ambler, Steve, Thorsten Koepl, and Jeremy Kronick. *The Consequences of the Bank of Canada's Ballooned Balance Sheet*. C.D. Howe Institute Commentary 631.
- November 2022 Richards, John, and Christopher Mabry. "Power When You Need It: The Case for Small Nuclear Reactors." C.D. Howe Institute E-Brief.
- November 2022 Bauslaugh, Randy. "ESG and Climate Change: Pension Fund Dos and Don'ts." C.D. Howe Institute E-Brief.
- November 2022 Drummond, Don, Duncan Sinclair, and Jillian Gratton. *Troubles in Canada's Health Workforce: The Why, the Where, and the Way Out of Shortages*. C.D. Howe Institute Commentary 630.
- October 2022 Shlesinger, Idan, Michelle Loder, and Gavin Benjamin. *Money for Life: Putting the "Pension" Back in Employee Pension Plans*. C.D. Howe Institute Commentary 629.
- October 2022 Gray, David, and Colin Busby. "Correcting Course: Employment Insurance Needs a Redesign to Counter Recessions and Achieve Equity." C.D. Howe Institute E-Brief.
- September 2022 Schirle, Tammy, Ana Ferrer, and Annie (Yazhuo) Pan. "Uneven Odds: Men, Women and the Obstacles to Getting Back to Work with Kids." C.D. Howe Institute E-Brief.
- September 2022 DeLand, Charles, and Alexander Vanderhoof. "Only Hot Air? The Implications of Replacing Gas and Oil in Canadian Homes." C.D. Howe Institute E-Brief.
- September 2022 Robson, William B.P., and Nicholas Dahir. *The Right to Know: Grading the Fiscal Transparency of Canada's Senior Governments, 2022*. C.D. Howe Institute Commentary 628.

SUPPORT THE INSTITUTE

For more information on supporting the C.D. Howe Institute's vital policy work, through charitable giving or membership, please go to www.cdhowe.org or call 416-865-1904. Learn more about the Institute's activities and how to make a donation at the same time. You will receive a tax receipt for your gift.

A REPUTATION FOR INDEPENDENT, NONPARTISAN RESEARCH

The C.D. Howe Institute's reputation for independent, reasoned and relevant public policy research of the highest quality is its chief asset, and underpins the credibility and effectiveness of its work. Independence and nonpartisanship are core Institute values that inform its approach to research, guide the actions of its professional staff and limit the types of financial contributions that the Institute will accept.

For our full Independence and Nonpartisanship Policy go to www.cdhowe.org.



C.D. HOWE
INSTITUTE

67 Yonge Street, Suite 300,
Toronto, Ontario
M5E 1J8