The economics of Canadian oil sands

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THE ECONOMICS OF CANADIAN OIL SANDS

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Abstract

We analyze the status of Canadian oil sands and examine future prospects. Our analysis suggests sustained activity in the sector in the medium- to long-term even with challenging changes in the surrounding economic and policy circumstances (in particular low oil prices and a redoubled commitment to more aggressive climate policies by Canada's provincial and federal governments). However, a combination of an expectation of a sustained increase in benchmark oil prices and the expected relaxation of transportation constraints will be needed to stimulate significant additional growth in production. We provide an overview of the basic production economics, as well as the economics and politics of getting product to market by pipeline and rail. A review of environmental impacts of Canadian oil sands development reveals significant concerns with respect to air quality, water quality, wildlife and other environmental impacts. However, we find that existing research on the environmental and wider social impacts is insufficient to underpin credible benefit-cost analysis of oil sands activities and development.

INTRODUCTION

The large-scale extraction of unconventional oil resources, including Canadian oil sands, together with the exploitation of shale gas (natural gas trapped in shale formations), has significantly reshaped the global energy landscape over the past two decades. Canadian oil sands have attracted significant attention because of their rapid growth, their significant share of Canadian exports and foreign direct investment, and their greenhouse gas emissions and other environmental impacts. The Canadian oil sands sector highlights many of the key issues we examine in economics and, as we will discuss here, the sector remains ripe for further research.

Oil sands are a sub-surface hydrocarbon deposit that contains a type of oil (called bitumen) that is mixed with sand, water, and clay. The world's largest oil sands deposits are in Canada, but there are also important deposits in Venezuela, the United States, Russia, and several other countries. Canada's oil sands are concentrated almost entirely in the province of Alberta, with the three largest deposits originally estimated to contain up to 1.8 trillion barrels of oil in place (Swart and Weaver, 2012). Oil sands operations produce bitumen - a black, viscous mixture of hydrocarbons - which is denser and higher in sulphur than most crude oils produced globally. Oil sands bitumen can either be processed into synthetic crude oil for use as a substitute for lighter crude oils or refined directly in complex refineries.

Commercial exploitation of Canadian oil sands began in 1967, but the most rapid growth has occurred since the turn of the century, when oil sands were part of a wider commodities boom in the Canadian economy.[1] In 2017, oil sands production averaged 2.9 million barrels per day, an almost four-fold increase over production levels in 2000.[2] Between 2000 and 2015, more than 270 billion Canadian dollars ($CAD) were invested in Canadian oil sands, and direct employment in the sector grew to more

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[1] Over the last two decades, the exploitation of Canada's oil sands deposits has coincided with the dramatic rise of oil production from shale, particularly in the United States (see Kilian, 2016, 2017).

[2] Canadian data used in this report are generally presented in cubic meters (m^3). One barrel of oil is equivalent to 0.1589 m^3 of oil.

than 70,000 employees (AER, 2016; PHRC, 2014). The effects on employment in the broader economy were much larger, with Kneebone (2014) estimating oil sands as directly or indirectly contributing 400,000 jobs in Canada by 2014.

More recently, the Canadian oil sands industry has been in a period of upheaval. World oil prices dropped more than 50% between June 2014 and June 2016, reaching prices that failed to cover the variable costs of production for some oil sands production facilities (see, for example, MEG Energy 2016).[3] While oil sands production continued to grow during the downturn, capital investment and production growth expectations have both fallen significantly since 2014. For example, Alberta Energy Regulator (2014) forecast bitumen production to grow from 2013 levels of 2 million barrels per day to 4 million barrels per day by 2023, with $250 billion in capital investment between 2014 and 2023. In contrast, Alberta Energy Regulator (2018) forecast production to reach 3.6 million barrels per day by 2023, with $160 billion in capital investment between 2014 and 2023.

This article analyzes the status of Canadian oil sands and examines the sector's future prospects. We start by discussing the key economic drivers of oil sands costs and how they affect supply decisions. Then we discuss transportation issues and the challenges of getting oil sands products to export markets. We next examine the likely impact of evolving climate change policy - both within Canada and outside - on operations, as well as other environmental issues that relate to oil sands operations. Finally, we highlight macro-economic impacts and considerations, namely the resource curse and Dutch disease. Overall, we find the future prospects for the Canadian oil sands industry to be highly uncertain.

KEY DRIVERS OF CANADIAN OIL SANDS COSTS AND FUTURE SUPPLY DECISIONS

[3] The significant weakening of the Canadian dollar against the U.S. dollar during this period cushioned the oil sands sector against further competitiveness losses. See Baumeister and Kilian (2016) for an analysis of the factors that contributed to the dramatic fall in oil prices.

This section identifies the key financial variables that determine costs in the Canadian oil sands sector, and thus producers' supply decisions. We develop project-level cost estimates for the two most common extraction techniques -- open pit mining and in situ extraction -- and use them to project future supply decisions in response to potential changes in the key variables.[4] Following Dixit and Pindyck (1994), Mason (2001) characterizes the decision to develop a new resource extraction project under uncertainty as an option with a trigger price (the price at which production of a particular project becomes profitable), and this is how we frame our analysis. We define our trigger price in terms of the constant real dollar West Texas Intermediate (WTI) oil price at which a prototypical new oil sands project would be expected to earn a 10% rate of return on capital.

Capital and Operating Costs

Oil sands projects have significant construction and operating costs. The only open pit mine currently under construction, Suncor's 180,000 barrel per day Fort Hills facility, is expected to cost a total of $16.2 billion (Suncor, 2018). In situ projects tend to be smaller and less costly per unit of production capacity; for example, the Kirby North project (40,000 barrels per day) is expected to cost $1.35 billion (Canadian Natural Resources, 2016). We use these capital costs as benchmarks for our analysis. Operating and maintenance costs in the sector vary significantly across facility and type of extraction (Ollenberger et al., 2016; CERI, 2015). Following central estimates from these sources, we assume

[4] Open-pit mines tend to be larger, longer-lived, and have higher total initial capital cost per unit of production capacity. In situ facilities are smaller in production capacity and have shorter project durations. They rely on paired wells, with the first drilled to inject steam to heat the bitumen in the deposit to render it less viscous and the second drilled to produce the heated bitumen. In situ facilities generally rely on natural gas more than mines, while truck-and-shovel (i.e., open pit) mines rely more heavily on diesel fuel. Evaluating the two project types separately allows us to be sensitive to important differences between them in terms of typical time-scales, environmental attributes, and cost structures.

operation, maintenance, and production-sustaining capital investment costs of $22 and $36 per barrel produced for in situ and mining extraction, respectively.

Product Discounts

As noted earlier, bitumen is either converted to synthetic crude oil or diluted with natural gas liquids and shipped as diluted bitumen for processing in complex refineries. We will focus our analysis on diluted bitumen as there are no projects planned which include integrated *upgraders* (basically a purpose-built refinery) to convert bitumen into synthetic crude. Like other heavier and higher-sulphur crude oil blends, diluted bitumen from oil sands is generally discounted relative to global benchmark oil grades. During 2017, the Canadian benchmark Western Canada Select diluted bitumen blend traded at an average of $12.77 per barrel below the WTI price, the North American benchmark for light crude; we use this value (adjusted for inflation) in our analysis, and allow it to vary for sensitivity analysis.[5] The price discount is due to differences in quality and geographic characteristics: oil sands diluted bitumen is denser and thus more expensive to transport, more expensive to refine, and yields a lower-value slate of products than a light, sweet (low-sulphur) crude in the same location (Nimana et al., 2015). Lower values for heavy crude are not exclusive to oil sands bitumen. For example, Mexican Maya crude traded on the US Gulf Coast at a $6.98 per barrel discount relative to Louisiana Light Sweet Crude in 2017 (Bloomberg data, author's calculations). Transportation costs are also reflected in the price discounts for oil sands diluted bitumen, with the marginal market being the US Gulf Coast.[6] The North American pipeline network has been affected by significant congestion, which has contributed to larger than expected

[5] We regard this as a conservative approach. The 5- and 10-year average discounts for bitumen relative to WTI have been $26.53 and $26.99 per barrel, respectively (Bloomberg data, authors' calculations). The differential has also been higher since November 2017. Thus, we also include a high-differential sensitivity case.

[6] Thus, Gulf Coast access costs $8.63 per barrel via the Enbridge system (National Energy Board, 2018b) and $12.75 per barrel via the TransCanada system (National Energy Board, 2018c).

discounts for Canadian diluted bitumen between 2010 and 2014 (Kilian, 2016; Oliver et al., 2014; Borenstein and Kellogg, 2014) and again in late-2017 and early 2018.

Royalties and Taxes

Among the major costs for oil sands operators are royalties paid to the government (which owns oil sands resources) and corporate income taxes. The oil sands royalty regime is a two-stage system. Initially, the developer pays the government a price-dependent share of gross revenues until the project has produced a cumulative return on capital invested that is equal to the long-term government bond (this is referred to as *payout*), after which the project is subject to higher royalties based on a share of profits (Plourde, 2009). At both stages, the share of production or profits payable as royalties depends on the WTI price per barrel in Canadian dollars. With the exception of financing costs, most project costs are used to calculate both the payout condition and the net revenue base on which royalties are calculated.[7]

In terms of corporate taxes, oil sands producers pay federal and provincial corporate income taxes at a current combined rate of 27%; they also benefit from special tax provisions available to all Canadian oil and gas production (KPMG, 2015).

An unresolved issue is whether oil sands production is actually subsidized. Some researchers have evaluated the level of government support by examining tax expenditures provided to the oil industry (including oil sands), which they find to be 2 - 3 billion $CAD per year (Sawyer and Stiebert, 2010; International Institute for Sustainable Development, 2010; Global Subsidies Initiative, 2011). Others have argued that the marginal effective tax rate on capital is higher in Canadian oil and gas than other industries (McKenzie and Mintz, 2011), suggesting that the combined effect of the current tax and royalty regimes has been to shift economic activity away from oil sands.

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[7] The initial gross revenue royalty rate is 1% when prices are below 55 $CAD per barrel and increases linearly to a maximum of 9% when oil prices reach 120 $CAD. After the project is deemed to have reached payout, the royalty payable is the greater of the gross-revenue royalty just described or a share of profits that increases from 25% (when the WTI price is less than 55 $CAD per barrel) to 40% (for oil prices at or above 120 $CAD per barrel).

Environmental Policies

Environmental policies also affect the costs faced by Canadian oil sands producers, and hence their supply decisions. First, prices on carbon are applied through a hybrid policy that has elements of both a carbon tax and a cap-and-trade regime (Leach, 2012). Regulations in place through 2017 provided an output-based allocation of emissions credits based on each facility's historical performance. In 2018, the output-based allocations changed to a benchmark-based system under which firms receive credits based on the performance of the 25th percentile producer, with separate allocations for in situ and mined bitumen production.[8] Credits are bankable and tradeable. If firms have insufficient credits to cover their emissions, then they may purchase credits from another firm, make a payment to the government in lieu of emissions reductions, or purchase regulated emissions offsets within Alberta. The possibility of compliance through a payment to the government sets the carbon price in Alberta. From 2007 through 2015, this price was 15 $CAD per tonne. The price was increased to 20 $CAD per tonne in 2016 and to 30 $CAD per tonne in 2017. Importantly, carbon charges and emissions abatement costs may be deducted from revenues in calculating both the royalty and tax base, implying that such costs are partly shared with the federal and provincial government.

Oil sands facilities are also responsible for the reclamation of their sites after extraction has been completed. Based on a study by the Canadian Energy Research Institute (CERI 2015), which assumes a reclamation cost that is equivalent to 2% of total capital expenditures, we assume that the future cost of reclamation is $CAD 0.25 per barrel for all production.

Results: Prospects for Future Oil Sands Supply

The future viability of oil sands production depends primarily on the expected evolution of global oil prices and low-cost access to markets. Using a discounted cash flow model of two prototypical oil

[8] One of the authors of this article, Andrew Leach, chaired the Government of Alberta's Climate Leadership Panel, whose recommendations were largely adopted by the government (Leach et al., 2016). The updated regime in Alberta (2017) forms the basis for our analysis.

sands facilities (one in situ and one mine) that produce diluted bitumen, and based on the assumptions just presented, we estimate the costs of new oil sands production. We then use these costs to estimate the critical (or trigger) oil price at which new production would be viable.[9] The trigger prices that we derive are substantially higher than realized prices for much of 2015-2017, with the bitumen mine requiring revenue levels that would be expected with WTI prices of $84.62 per barrel in order to earn a nominal rate of return of 10% on invested capital, while the trigger price for the in situ plant is $58.06 per barrel WTI. These values translate to required revenues at the plant gate (i.e., before transportation) of $61.62 and $35.85 per barrel bitumen, respectively.[10] These estimates are consistent with estimates from Alberta Energy Regulator (2018), which reported a required WTI range of $75-85 per barrel for mines and $45-55 per barrel for in situ plants. These high trigger prices clearly indicate why new development of Canada's oil sands have slowed significantly since 2015.

Despite the drop in oil prices in late 2014, work on Canadian oil sands projects currently under construction has continued and those that began before the oil price crash are expected to enter production at close to their original schedules. Given the substantial sunk costs, expected oil prices would have to fall significantly from current levels for those projects currently under construction to be abandoned or operating projects to shut down. More specifically, using an analysis similar to the one used to estimate the costs of new oil sands production, we find that while a new in situ project would not be developed unless average oil prices were expected to remain above $58 per barrel, price expectations would have to drop below $45 per barrel to trigger the suspension of a project for which two-thirds of the construction costs had already been incurred. Other than projects currently under construction, the lowest-cost future development would be expansion of some existing facilities. For example, Ollenberger et al. (2016) find

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[9] Appendix Table 1 presents a list of the assumptions underlying these estimates and Appendix Table 2 presents the detailed cost estimates.

[10] This includes the costs of diluting and shipping a barrel of bitumen and the discount at which diluted bitumen trades to lighter oil blends.

that significant expansions of both existing in situ and oil sands projects are viable at average WTI prices below $50 per barrel. Our model predicts that a prototypical expansion of an in situ project would be viable at approximately $50 per barrel, depending on the assumed reduction in total capital costs due to already-sunk costs.

GETTING PRODUCT TO MARKET: TRANSPORT CHALLENGES

The analysis just presented does not consider the evolving challenges to the large-scale transportation of oil sands product to markets, particularly for export. We discuss these challenges here.

Alberta Energy Regulator (2018) reports that of the 2.7 million barrels per day of total oil sands production in Alberta in 2017, 375,000 barrels per day were used within the province, while 650,000 barrels per day of upgraded oil sands product and 1.5 million barrels per day of non-upgraded bitumen were removed from Alberta.[11] The latter includes product shipped to US markets and to Canadian markets outside the province. Most of these volumes move by pipeline, although some exports occur by rail.[12]

Export capacity is extremely tight. In December 2017, the largest export pipeline systems, Keystone (27%), Enbridge Mainline (5-21%), and Trans-Mountain (23%), were all over-subscribed (by the percentages shown in brackets) relative to their maximum capacity (NEB, 2018). Although pipeline expansions are underway in the Enbridge system, even a conservative production growth case would lead to export volumes exceeding effective pipeline capacity unless additional new pipeline projects are undertaken (NEB, 2017).

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[11] We use “removals” to indicate movements out of the province, including volumes shipped to other Canadian provinces. We use exports to denote shipments to destinations outside of Canada.

[12] In December of 2017, less than 5% of total crude oil exports were shipped by rail (National Energy Board, 2018).

The construction of new oil sands pipelines has been a key issue in North America. Pipeline safety concerns were exacerbated by two spills of oil sands diluted bitumen (in Kalamazoo, Michigan and Mayflower, Arkansas in 2010 and 2013, respectively). These safety concerns, coupled with concerns about greenhouse gas emissions, resulted in increased opposition to pipelines, culminating in the US with President Obama's rejection of the Keystone XL pipeline (in late 2015) and in Canada with major political battles and protests over pipeline proposals. Although President Trump reversed the Obama administration decision on Keystone XL in 2017, the pipeline continues to face regulatory challenges and stiff local opposition.

Several other pipeline projects have been proposed to increase capacity to ship oil derived from the Alberta oil sands. The TransMountain Expansion (590k bbl/d) to the Canadian West Coast and the Line 3 refurbishment and Line 67 expansion of the Enbridge system to the US Midwest (370k bbl/d) have received Canadian regulatory approval.[13] The proposed Northern Gateway Pipeline (525k bbl/d) to the Canadian West Coast had its federal regulatory approval overturned by the courts and was subsequently denied by the Canadian government in 2016 (Gitxaala Nation v. Canada, (2016), Government of Canada (2016)). The Energy East (1100k bbl/d) pipeline, the only proposed oil pipeline to the Canadian East coast, was cancelled and withdrawn from the regulatory process by TransCanada in 2017.

Shipping by rail presents the only plausible alternative to transport by pipeline. In general, shipping oil by rail costs substantially more per barrel-mile than shipping by pipeline. However, there are factors related to specific characteristics of the transportation of oil sands bitumen that narrow the gap between pipeline and rail costs. The most important of these is that shipping bitumen by rail requires less dilution, thus reducing both the total volume of product shipped and the costs attributable to purchase of the diluting agent. Estimates of the per-barrel cost advantage of pipelines over rail vary from $3-$4 (U.S. Department of State, 2014) to $9 (TransCanada, 2016). Without new pipeline capacity, it is widely expected that oil sands production will be lower than would otherwise be the case, because net revenues

[13] Note that construction is underway on Line 3.

will be lower if incremental production must rely on shipments by rail. For example, National Energy Board (2016a) estimates that a scenario with no new pipelines constructed would lead to an 8% reduction in total Canadian oil output, and a 13% (400,000 barrel per day) reduction in peak oil sands output. These findings are driven by an estimated reduction of $9.20 in the price of diluted bitumen at the Hardisty, Alberta hub. The U.S. Department of State (2014) found similar results concerning oil price levels in their analysis of the Keystone XL pipeline. Given these results, we recalculated our model results for a scenario with higher discounts for Canadian diluted bitumen and find that these discounts have significant impacts. More specifically, we find that under the U.S. Energy Information Administration's Reference Case for oil prices, a $9 per barrel additional discount on Canadian crude would reduce the rates of return on in situ projects from 17% to 13% and on mining projects from 8% to 5.5%.

Whether reached by pipeline or rail, the United States represents the most important market for any additional exports of Canadian oil sands production.[14] In 2017, Canada exported 2.7 million barrels per day of heavy crudes (including diluted bitumen) to the US via pipeline, which represented 56% of total US imports of this grade of crude oil (Energy Information Administration, 2017). Thus, there is significant potential to increase shipments of non-upgraded bitumen to the US. Although there are other markets for heavier crudes such as those produced from oil sands, the US market remains the closest major market and is therefore likely to be served first.

CANADIAN OIL SANDS AND CLIMATE CHANGE POLICIES

Climate change policies in Canada, the United States, and globally are evolving rapidly. As a producer of a carbon-based product, Canada's oil sands sector – and its future prospects -- will clearly be affected by these policies.

Climate Impact

[14] Other potential markets include India and China, which could be served from the West or East coasts.

Operations in the Canadian oil sands affect greenhouse gas (GHG) emissions in two ways. One is the emissions generated in the process of extraction, processing, and transport. The other is the release of carbon when the product is finally used.

Oil sands operations in Alberta are a large and growing source of GHG emissions, with emissions increasing from 15.3 million metric tons of carbon dioxide equivalent ($MtCO_2e$) in 1990 to 69.3 $MtCO_2e$ by 2016 (Environment Canada, 2018a). Oil sands accounted for 10.2% of total GHG emissions in Canada in 2016, and are projected to increase to 15.9% (115 $MtCO_2e$) of total Canadian emissions by 2030 (Environment Canada, 2018b).

Moreover, oil refined from oil sands has higher life-cycle emissions than comparable products produced from most other crude sources (Brandt 2011; Bergerson et al., 2012; Cai et al., 2015; Gordon et al., 2015). More specifically, the California Air Resources Board (2015) estimates the carbon intensity values for refined products derived from Western Canada Select (the heavy oil blend price we have used to proxy for diluted bitumen values) to be 18.43 grams per megajoule (g/MJ), which is much greater than the 12.03g/MJ estimated for WTI crude and the 8.71g/MJ estimated for North Dakota Bakken crude. The estimated carbon intensity of products sourced via oil sands production also varies significantly across facilities, ranging from 12.05g/MJ for Kearl Lake bitumen to 37.29g/MJ for Long Lake synthetic. This suggests that depending on how it is differentiated by source, carbon pricing applied to oil users could disproportionately affect the attractiveness of oil sands in general, and the output of facilities generating more carbon intensive output in particular.

Significant concerns have been raised about the impact of oil sands emissions on global climate change. Sometimes this has involved emotional language. For example, Hansen (2012) characterized the exploitation of oil sands resources as “game over for the climate,” and high-profile environmentalist Bill McKibben (2011) has called oil sands “the biggest carbon bomb on the planet.” The findings in the peer-reviewed literature have been less definitive on the potential role of oil sands extraction in exacerbating global climate change. Swart and Weaver (2012) find that if extracted and combusted, the entire oil sands resource would increase global average temperatures by 0.36°C, and that combustion of current oil sands reserves[15] would increase global average temperatures by 0.03°C.

Implications of Climate Policy for the Oil Sands Sector

Existing research is also mixed concerning the future of oil sands development if the world takes serious action on climate change. For example, McGlade and Ekins (2015) find that under cost-effective policies to reduce GHG emissions to levels consistent with a 2°C increase in global mean temperature, there would be no new oil sands development and existing production would be rapidly curtailed, with cumulative production falling sharply from the NEB (2016b) forecasts (i.e., from 38 billion barrels by 2040 to 7.5 billion barrels by 2050). Under similar global emissions constraints, McGlade and Ekins (2014) find that future oil sand production rates depend on whether carbon capture technology (CCS) is readily available.[16] With CCS, production rates would increase to 4.1 million barrels per day in 2035, while remaining roughly constant at current levels if CCS technology is not viable. Chan et al. (2012) find that bitumen production increases 4-fold in the absence of global action on climate policies but that, "climate policy significantly dampens the prospects for Canadian oil sands development because global demand and the producer prices of oil are depressed, and the Canadian CO_2 policy adds to the cost oil sands production." Leach and Boskovic (2014) find that oil sands production is likely to continue under a global carbon price set at the social cost of carbon if and only if a significant share of the carbon cost is borne by oil consumers.[17]

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[15] This is estimated to be approximately 100 years of production at 5 million barrels per day, which is just below the peak rate forecast in NEB (2016a).

[16] CCS is the process of capturing waste carbon dioxide from large point sources, transporting it to a storage site, and depositing it where it will not enter the atmosphere, normally in an underground geological formation.

[17] The social cost of carbon is an estimate of the monetized damages caused by a one tonne increase in carbon omitted in a year.

While it is likely that global action on climate change would preclude significant expansion of oil sands production in the absence of significant technological advances, it is more difficult to assess the impact of climate change policies on the viability of *existing* projects in Canada. Higher domestic carbon prices have impacts that are analogous to lower oil prices or higher transportation costs, although with slightly different royalty implications. Carbon costs are deductible from both the tax and royalty base, so approximately 50% of any increased carbon cost is effectively passed-through to provincial and federal governments through reduced tax and royalty payments (Leach and Boskovic, 2014).

The production-weighted average emissions per barrel produced from oil sands (using 2014 Alberta government data) was 0.055 metric tons per barrel (t/bbl). This means that each dollar in average carbon cost would increase the average cost of existing oil sands production by $.055 per barrel, suggesting that it is likely that existing operations could withstand significant increases in domestic carbon prices without inducing a significant shut-down of operations.

Overall Impact of Climate Policies

Overall, we find that the impact of evolving climate policies on oil sands development is likely to be felt most acutely through the impacts of these policies on global oil prices. Since roughly 80% of the total life cycle emissions from the production and combustion of a barrel of bitumen occurs in refining, transportation, and final combustion, the impact of downstream emissions pricing will likely be greater than the impact of policies affecting only production emissions. This suggests that the greatest climate policy risks for oil sands are from the oil market impacts of global action on climate change, not domestic climate change policies.

OTHER ENVIRONMENTAL ISSUES FACING CANADIAN OIL SANDS

In addition to climate impact, there are there are important local environmental and ecological impacts related to oil sands production, including the accumulation of mine tailings, land reclamation, and negative impacts on populations of caribou and other fauna.[18] In this section, we discuss these issues in more detail as well as potential government actions aimed mitigating them.

Accumulation of Mine Tailings

After oil sands have been mined, the ore is mixed with hot water and chemical solvents to separate bitumen from sand, clay, and other impurities. The resulting slurry goes through an extraction process to remove the bitumen. The remaining components are called tailings. Tailings are transported and stored in large 'ponds' – engineered systems that involve dams and dykes. In 2015, tailings ponds in Alberta contained 1.18 trillion of fluid tailings and covered more than 220 square kilometres (McNeill and Lothian, 2017). The appropriate management of these tailings, which contain many compounds that are potentially harmful to the environment, is a major issue for the oil sands sector.

Environmental impacts

Tailings have a number of potential environmental impacts. The Council of Canadian Academies[19] (2015) identified problems that can arise from toxic seepage into groundwater and rivers and the potential ecological implications of catastrophic dyke failures. However, empirical evidence concerning these impacts is rather limited. In one exception, Kelly et al (2010) provide evidence linking elevated levels of thirteen important pollutants in the Athabasca river system in northeastern Alberta to oil sands operations, including tailings. In the longer term, the extent to which successful reclamation of land

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[18] It is important to note that oil sands operations are concentrated in the northeastern corner of Alberta, a remote area where few people live or visit. Thus, justification for governmental regulation of environmental and ecological impacts must often be based on *non-use* values (i.e., the value that people assign to goods, including public goods, even though they have never and will never directly use them).

[19] The Council of Canadian Academies is a highly respected not-for-profit organization that conducts expert evidence reviews in support of public policy development in Canada. It includes three member academies: the Royal Society of Canada, the Canadian Academy of Engineering, and the Canadian Academy of Health Sciences.

contaminated by tailings is likely to be feasible, and at what cost, is also disputed (Pembina Institute, 2008).

There is also comparatively little evidence concerning the contribution of tailings facilities to air pollution, and the likely associated impacts. However, Galarneau et al. (2014) find that tailings ponds are a much more significant source of polycyclic aromatic hydrocarbons (PAHs), which can negatively impact human health, than previously believed. Moreover, the environmental implications of such discharges for *regional* ecosystems are not well-understood.

Government policies

Tailings are a classic stock pollution problem. Research and policy work have examined options for both stemming the rate of deposition of new tailings and reducing the stock as part of efforts to reclaim the affected landscape.[20] In an effort to slow the generation of tailings, the Alberta Energy Regulator regulates oil sands producers to encourage reduced tailings deposition.

Although the underlying physical science regarding the short and longer term impacts of tailings on the environment of Alberta remains under-developed, attempts to actually monetise or otherwise weigh those impacts in a way that could be included in a benefit-cost analysis is essentially non-existent. This points to an urgent need to support further research in this area to provide credible estimates of impacts in a form that can support policy evaluation and appraisal.

Reclamation of Tailings and Mine Sites

Oil sands companies are responsible for restoration of their sites after use. This includes tailings areas and land used for other purposes. There has been some progress in the remediation of existing tailings ponds. Suncor Energy became the first oil sands company to complete surface reclamation of a

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[20] In terms of flow, the production of 1 barrel of synthetic crude oil requires approximately 2.5 barrels of water and 2 tonnes of oil sands ore, yielding around 3.3 barrels of raw tailings. While much of the water used is recycled from existing tailings ponds, the long-run equilibrium sees approximately 2 barrels of mature fine tailings produced for every barrel of oil (Hrudey et al., 2010).

tailings pond. Reclaiming the 220 hectare site north of Fort McMurray involved moving over 65,000 truck-loads of soil and the planting of around 630,000 trees and shrubs (Marketwire, 2010)). However, the success of that project -- i.e., the extent to which the area returns to being a self-sustaining ecosystem -- can only be assessed with the passage of time. Other reclamation technologies are in the test phase, and thus not yet commercially viable.

There has also been significant work on the reclamation of oil sands mine sites, although the actual rate of reclamation is low. The total oil sands extraction area in Alberta is roughly 89,000 hectares, with only about 8,000 hectares of that at some stage of reclamation. Only 237.6 hectares of land (less than 0.5% of the total disturbed landscape) have been certified as reclaimed and returned to government jurisdiction (Alberta Energy Regulator, 2017), indicating a substantial challenge for land restoration in the future.

There is significant research on the technical challenges to restoring oil sands landscapes to their original productive capacity after oil extraction has been completed (e.g., see Hrudey et al., 2010). In addition to the challenges of reclaiming lands currently used as tailings ponds, reclamation of fenland, muskeg swamp, and boreal forest landscape have all proven challenging. From an economic standpoint, we found nothing on the relative value of land restored to a productive but not fully-restored landscape.

In order to provide financial assurance of reclamation, companies must provide security deposits to the Government of Alberta to ensure the work is done. More specifically, companies are allowed to use the value of their extraction assets, which is a function of the price of oil, as collateral for their unfunded future reclamation liabilities. As of September 2017, the Government of Alberta held just under $1 billion in financial security (Alberta Energy Regulator, 2017), compared to the most recent public estimate of liability of $20.8 billion (Office of the Auditor General of Alberta 2015). Going forward, as with the decommissioning costs related to nuclear power projects, the future costs of restoring the oil sands areas of Alberta (after production ends), and the extent to which partial restoration will be socially acceptable, need to be given careful consideration when evaluating oil sands projects.

Impacts on Caribou and Other Fauna

The negative impact of oil sands on faunal biodiversity has drawn significant media and public attention. The plight of the woodland caribou, in particular, has received a great deal of attention (Hervieux et al., 2013).[21]

Alberta is home to fifteen herds of woodland caribou, and the caribou is listed as a threatened species under the Canadian Species at Risk Act. This regulation requires both the identification of key threats and the development of an intervention plan (Environment Canada, 2012). Oil sands operations have been identified as factors in the decline of woodland caribou, but the magnitude of this influence is disputed. Hrudey et al. (2010) highlight the role of habitat fragmentation. Roads – many developed or used primarily for oil sands business – act as semi-permeable barriers to caribou movement and pipeline rights of way allow predator movement into caribou territory (Dyer et al. 2002; Jordaan et al., 2009). Boutin et al. (2012) suggest a multi-stage process in which human disturbance in the oil sands region has led to habitat fragmentation and to increases in the deer population, which in turn has led to an increase in wolf populations. Latham et al. (2011a, 2011b) find that wolves' use of road and pipeline rights-of-way for movement has changed the predator-prey balance in a way that puts caribou at a disadvantage.

In June 2016, the Alberta Government introduced its Caribou Action Plan, which includes several proposed actions to ensure caribou recovery (Government of Alberta, 2016). The current policy includes the expansion of protected areas as well as predator control, specifically through the culling of wolves. Schneider et al. (2010) recommend a three-pronged approach to management -- habitat protection, restoration of disturbed areas, and predator control. Boutin et al. (2012) argue that although unpopular,

[21] Two studies have used stated preference methods to estimate the value of the existence of caribou (Adamowicz et al., 1998; Harper, 2012). The estimated willingness-to-pay for an increase in the number of herds is approximately $CAD 184 (to increase from two to three herds) or $CAD 268 (to increase from two to seven herds).

the wolf culls are necessary because the other two approaches will not eliminate the causes of population decline in time to preserve viable herds.

Policies aimed at protecting caribou also affect the economics of oil sands. Boskovic and Nostbakken (2016a) find that, on average, regulations designed to protect caribou decrease the value of oil sands lands by 24% on average, or $CAD 192 per hectare, leading to a $CAD 1.15 billion reduction in government leases and royalties. Boskovic and Nostbakken (2016b) examine the impact on lands likely to see future regulation, finding that the value of leases in currently unregulated areas decreases by an average of 16% relative to geologically similar leases further from caribou protected areas. For areas within 5km of a currently regulated area, the value of the lease decreases by 22%.

In summary, oil sand operations may have important impacts on both the health of caribou populations and other fauna in Alberta. However, we found little or no economic analysis that allowed for these impacts to be included in a benefit-cost framework.

POSITIVE AND NEGATIVE MACROECONOMIC IMPACTS

Next we examine the impacts of Alberta's oil sands sector on the wider economy. The channels for positive macroeconomic impacts are clear: employment, government revenues, and real wages in Alberta all increased well above national averages from the early 2000s through mid-2014, and wages, productivity, and employment in Alberta were still well above national averages in 2017. However, there is a substantial literature that suggests that large resource endowments may have negative macroeconomic impacts on a jurisdiction and actually lower its well-being; some of these negative impacts have been studied in Alberta. Two concepts that have often been discussed in this regard are the resource curse and Dutch disease.

The Resource Curse

Potentially the most pervasive of these macro-economic impacts, the "resource curse" describes a deleterious effect of increased resource wealth on governance, educational attainment and other socio-economic impacts. Sachs and Warner (1995, 2001) and others have identified several channels through which the resource curse can occur. For example, the lure of significant wealth associated with the resource bounty induces rent-seeking behaviour, often on the part of political actors; this effect is likely to be particularly pronounced when there are weak legal institutions (Brunnschweiler and Bulte, 2008). Some have argued that such an effect has occurred in Alberta, pointing in particular to successive governments' decisions to spend resource revenue for current consumption rather than saving it to a sovereign fund, as has been done in Norway (Parlee, 2015).[22]

Dutch Disease

Another possible negative macroeconomic effect of a large resource endowment is the "Dutch Disease," whereby the presence of significant potential rents pulls resources away from other sectors. In particularly dramatic cases, the other sectors wither (Economist, 1977). Sachs and Warner (1995) find that Dutch Disease can be a source of anemic growth, "if there is something special about the sources of growth in manufacturing." Here the market failure would be sector-level returns to scale that are not accounted for in individual decisions. Two questions remain un-answered in the debate over the potential rise of Dutch Disease in Canada: first, did an additional decline in manufacturing occur as a result of the rise in resources and second, does this substitution of economic activity away from manufacturing matter?

There is fairly compelling evidence indicating an accelerated decline in traditional manufacturing in Canada, as the resource boom pulled resources into oil sands, causing an increase in prices of key related inputs and wages. There is also evidence that the appreciation of the Canadian dollar, in part due to the commodity boom, accelerated this transition. For example, Beine, Bos and Coulombe (2012) estimate that 42% of the substantial appreciation in the Canadian dollar between 2002 and 2008 was due to the increased value of resource exports, especially, but not uniquely, oil sands. They also find that 31%

[22] There is some evidence that educational attainment and the accumulation of human capital is adversely affected by resource booms (Parlee, 2015). However, Emery et al. (2012) found that although the oil boom in Alberta between 1973-1981 changed the timing of schooling, it did not affect total human capital accumulation over the long term.

(approximately 100,000 jobs) of all manufacturing job losses during the same period can be attributed to the rise in the exchange rate driven by Canadian economic activity. Krzepkopwski and Mintz (2013) argue that the declines observed in the manufacturing sector are the continuing result of factors other than the resource boom and suggest that, with or without the oil sands industry, the high-wage manufacturing jobs which had been the mainstay of central Canada's economy for decades were unlikely to return.

Boadway et al. (2013) take a different approach, examining whether Canada's institutions of fiscal redistribution have the capacity to deal with resource booms. They recommend changes to the system through which resource rents are collected and redistributed within the country and through increased infrastructure spending in other regions to offset the economic pull of resource-rich regions; they also encourage more saving of resource rents in sovereign wealth funds.

Thus, the literature consistently finds significant macroeconomic impacts of the oil sands boom, and more generally finds an increase in the overall standard of living, which is provided by the increase in natural resource wealth and activity due to the oil sands boom, at least since the early 2000s. However, the literature also finds significant transition and volatility costs, institutional failure, and a potential long-term impact of lost educational attainment due to the resource boom. It is important to further estimate the value of these impacts, but some values will only become clear in the longer term.

SUMMARY AND CONCLUSIONS

This article has discussed key issues in the economics of Canadian oil sands. We find that production from Canadian oil sands requires that the WTI oil price exceed $58 per barrel. While the oil price was markedly lower for a period of time, it has recently risen above $60, suggesting the potential for substantial increases in oil sands production. We also find significant uncertainty due to potential transportation constraints. If currently proposed pipeline projects do not proceed, for example because of legal hurdles and local regulatory processes, the required price to trigger investment in new oil sands projects is approximately $9 per barrel higher than would otherwise be the case. Regarding the non-market costs associated with oil sands, there has been insufficient economic analysis concerning air quality, water quality, wildlife, and other environmental impacts. This gap in the literature presents a substantial challenge to conducting a thorough benefit-cost analysis of Canadian oil sands.

Due to space limitations, we have not discussed water quality and quantity policies (Allen, 2008; Schindler and Donahue, 2006); issues concerning airborne pollution deposition on land and water (Kelly et al., 2010); and oil sands' contribution to particulate matter and acid-rain-causing pollution (Hrudey et al., 2010). We have also omitted discussion of the complex relationship between Canada's First Nations and oil sands development. Many First Nations and Metis communities in the oil sands area have important commercial relationships with oil sands companies, and many First Nations communities have been supportive of proposed pipeline projects. However, there are also multiple legal actions by First Nations communities against oil sands operations, against the provincial governments for violations of historic treaty rights, and against pipeline projects currently under development.

If global oil prices continue to recover, oil sands production may be poised to play an increasing role in global markets. However, any expansion of oil sands is likely to lead to a host of external effects, including climate impacts, adverse impacts on local flora and fauna, and externalities associated with transportation.[23] On the other hand, increased production will add to the consumer surplus in downstream petroleum markets, and the associated expansion is likely to generate benefits to local economies. A full and careful comparison of these costs and benefits would be both timely and important. Our hope is that the discussions in this article will encourage such an analysis.

[23] If pipeline capacity does not expand to keep pace with production, the increased production will most likely be shipped via rail; in turn, this increase in rail traffic is likely to yield external costs related to safety (Mason, 2018) and local air pollution (Clay et al., 2018).

Appendix

Project parameters	In situ	Mine	Time trends	In situ	Mine
Capacity (barrels per day)	40000	180000	Inflation	2%	
Build time (yrs)	3	4	Long term bond rate (for royalty calculation)	2%	
Total years of production	30	50	Fuel use (diesel, natural gas) improvement per barrel	1%	
Cumulative production (million barrels)	385	3180	Emissions intensity improvement (ex fuel)	1%	
Costs ($CAD 2018)			**Tax pool allocations for capital expenditure**		
Construction Costs (millions)	1350	16200	Capital Cost Allowance (Class 41, 25% of declining balance deductible each year)	85%	95%
Maintenance Costs ($ per barrel)	5	3			
Operating Costs ($ per barrel)	10	16	Canadian Oil and Gas Development Expense (30% of declining balance deductible each year)	15%	5%
Recurring Capital Costs ($ per barrel)	9	6			
Deemed expenses for future reclamation ($ per barrel)	0.25				
			Taxes		
GHG Emissions (Carbon Dioxide Equivalent)			Combined Corporate Tax Rate	27%	
Production emissions intensity (tonnes/barrel)	0.058	0.038			
Life cycle emissions (grams/bbl)	575	535	**Royalties**	**Gross**	**Net**
Light oil life cycle emissions (grams/bbl)	500		Minimum Royalty Rate	1%	25%
			Maximum Royalty Rate	9%	40%
Greenhouse Gas Policies			Lower limit, formula - C$/bbl	55	
Carbon price ($/tonne real)	30		Upper limit, formula - C$/bbl	120	
Output-based allocation rate (where applicable, t/bbl)	0.055	0.035			
Carbon price escalation (annual increase in real price)	2%				
Decrease in annual output-based allocation	2%				

Appendix Table 1 Key model parameters, project cost, and fiscal policy assumptions

Oil sands supply costs and financial metrics	Projects under current prices and policies		Projects under EIA (2018) Reference Case Prices, Current Policies		Projects under EIA (2018) High Oil Price Case, Current Policies		Projects under EIA (2018) Low Oil Price Case, Current Policies		Projects under EIA (2018) Reference Case, Current Policies, High Differential	
	In-situ	Bitumen Mine	In-situ	Bitumen Mine	In-situ	Bitumen Mine	In-situ	Bitumen Mine	In-situ	Bitumen Mine
Project Financial Indicators										
Internal Rate of Return (%)	8.79%	N/A	16.93%	7.96%	33.48%	18.78%	-5.08%	N/A	12.71%	5.56%
Supply Cost (WTI equivalent $/bbl)	58.06	84.62	67.70	109.13	68.47	109.54	52.94	84.37	77.59	119.40
Supply Cost (plant gate bitumen $/bbl)	35.85	61.61	41.24	81.43	41.99	81.84	32.03	62.51	41.68	82.24
Revenues and Costs ($CAD 2018 per bbl bitumen)										
Total Revenue	41.00	40.95	74.02	83.66	190.90	219.54	25.92	31.56	60.88	70.52
Capital and Debt Costs	12.99	10.24	12.76	11.34	12.76	11.34	12.76	11.34	12.76	11.34
Operating Costs	15.34	32.96	16.69	35.60	17.94	42.51	17.41	33.58	16.69	35.60
GHG Compliance Costs	0.20	0.41	0.20	0.41	0.20	0.41	0.20	0.41	-	-
Royalties	4.84	3.08	17.83	15.33	64.31	66.61	0.97	2.06	0.20	0.41
Taxes	2.56	-	7.66	6.09	26.31	26.99	-	-	12.82	10.53
Free Cash Flow	5.06	(5.74)	18.89	14.88	69.37	71.69	(5.41)	(15.83)	5.47	3.96
Key Commodity Price Assumptions ($2018)										
WTI Crude Oil at Cushing ($/bbl)	55.96		102.27		231.21		41.81		102.27	
Natural Gas at AECO/NIT ($/MMBtu)	2.50		4.46		5.81		3.98		4.46	
Diluted Bitumen at Hardisty ($/bbl)	43.10		89.50		218.44		31.70		80.52	
Bitumen value at plant gate ($/bbl)	33.81		78.45		203.52		24.12		65.62	
Diluted bitumen discount to WTI ($/bbl)	12.86		12.77		12.77		10.11		21.75	
$CAD/$US	1.22		1.03		1.03		1.30		1.03	

Appendix Table 2: Estimates of oil sands supply costs
Notes: The *Current Prices and Policies* scenarios rely on WTI and Henry Hub natural gas 60-month forward curves as well as the 60-month forward curve for the Canadian dollar exchange rate as of March 22, 2018. The Reference, High Oil, and Low Oil Price cases are from EIA (2018). All commodity prices are in $US. Henry Hub natural gas prices are converted to Alberta Energy Company/Nova Energy Transfer (AECO/NIT) hub prices using a $0.50/GJ discount. Beyond 2023, forward curve prices for oil and natural gas are treated as constant in real terms and exchange rates are treated as constant.

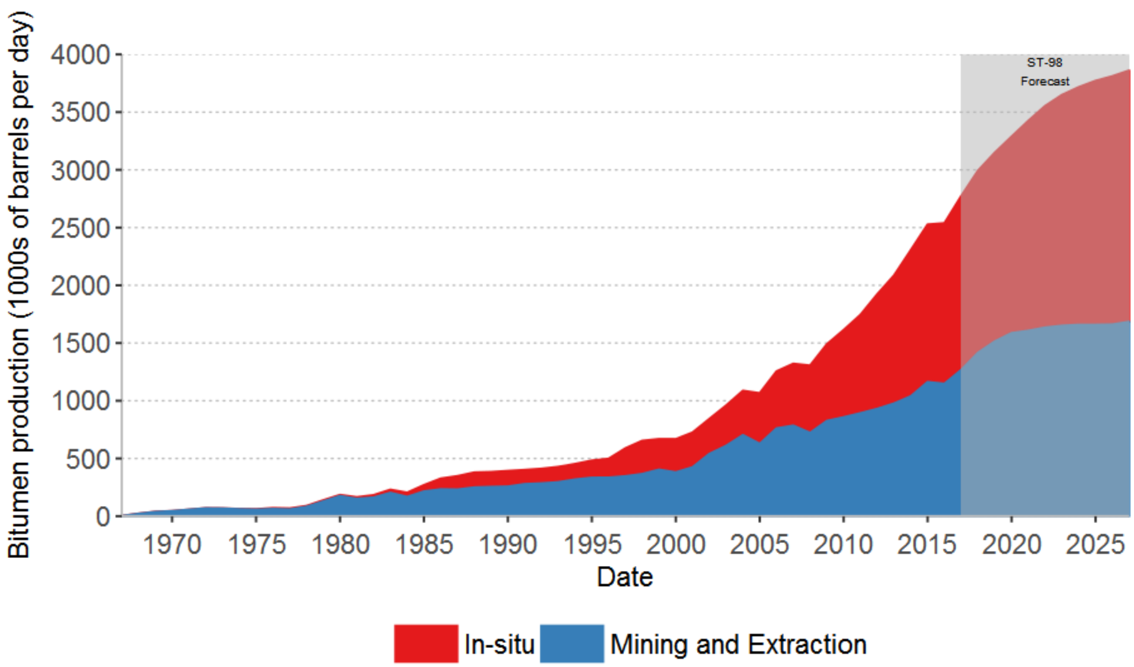

Figure 1 Mined and in situ bitumen production from 1967 through 2017 and projections from 2018 through 2027. Source: Alberta Energy Regulator (2018).

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