Canadian Oil Sands Supply Costs and Development Projects (2018-2038)
CANADIAN OIL SANDS SUPPLY COSTS AND
DEVELOPMENT PROJECTS (2018-2038)
Canadian Oil Sands Supply Costs and Development Projects (2018-2038)

Author: Dinara Millington

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# Acronyms and Abbreviations

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<tr>
<td>AECO-C Price</td>
<td>Natural gas price benchmark in western Canada</td>
</tr>
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<td>AEO</td>
<td>Annual Energy Outlook</td>
</tr>
<tr>
<td>AER</td>
<td>Alberta Energy Regulator</td>
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<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>BCFPD</td>
<td>billion cubic feet per day</td>
</tr>
<tr>
<td>BPD</td>
<td>barrels per day</td>
</tr>
<tr>
<td>CAPP</td>
<td>Canadian Association of Petroleum Producers</td>
</tr>
<tr>
<td>CCA</td>
<td>Capital Cost Allowance</td>
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<tr>
<td>CCI</td>
<td>Carbon Competitiveness Incentive</td>
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<tr>
<td>CERI</td>
<td>Canadian Energy Research Institute</td>
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<tr>
<td>CO2eq.</td>
<td>carbon dioxide equivalent</td>
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<tr>
<td>CSS</td>
<td>Cyclic Steam Stimulation</td>
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<tr>
<td>EIA</td>
<td>Energy Information Administration</td>
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<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
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<tr>
<td>GDP</td>
<td>Gross Domestic Product</td>
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<tr>
<td>GHG</td>
<td>greenhouse gas</td>
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<tr>
<td>GJ/d</td>
<td>gigajoules per day</td>
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<tr>
<td>LTBR</td>
<td>Long-term Bond Rate</td>
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<tr>
<td>LNG</td>
<td>Liquified Natural Gas</td>
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<tr>
<td>MMBPD</td>
<td>million barrels per day</td>
</tr>
<tr>
<td>MMBTU</td>
<td>million British Thermal Unit</td>
</tr>
<tr>
<td>MMCFPD</td>
<td>million cubic feet per day</td>
</tr>
<tr>
<td>MT or Mt</td>
<td>megatonne</td>
</tr>
<tr>
<td>MWh</td>
<td>megawatt hour</td>
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<tr>
<td>NEB</td>
<td>National Energy Board</td>
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<tr>
<td>NGL</td>
<td>Natural Gas Liquid</td>
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<tr>
<td>NPV</td>
<td>Net Present Value</td>
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<tr>
<td>OPEC</td>
<td>Organization of Petroleum Exporting Countries</td>
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<tr>
<td>R &amp; D</td>
<td>Research and Development</td>
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<tr>
<td>SAGD</td>
<td>Steam-Assisted Gravity Drainage</td>
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<tr>
<td>SCO</td>
<td>Synthetic Crude Oil</td>
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<tr>
<td>SGER</td>
<td>Specific Gas Emitters Regulation</td>
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<tr>
<td>SOR</td>
<td>Steam to Oil Ratio</td>
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<td>US</td>
<td>United States</td>
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<td>USGC</td>
<td>United States Gulf Coast</td>
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<td>WCS</td>
<td>Western Canadian Select</td>
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<td>WTI</td>
<td>West Texas Intermediate</td>
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Executive Summary

Each year the Canadian Energy Research Institute (CERI) publishes its long-term outlook for Canadian oil sands production and supply in conjunction with an examination of oil sands supply costs. This is the twelfth edition of CERI’s oil sands supply cost and development projects update report. Like past editions of the report, several scenarios for oil sands developments are explored. Also, given the assumptions for the current cost structure, an outlook for future supply costs will be provided.

Supply Cost Results
Supply cost is the constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes and earn a specified return on investment. Supply costs in this study are calculated using an annual discount rate of 10 percent (real), which is equivalent to an annual return on investment of 12 percent (nominal) based on the assumed inflation rate of 2 percent per annum.

Based on these assumptions, the supply costs of crude bitumen for a greenfield SAGD and an expansion phase SAGD have been calculated. Figure E.1 illustrates the supply costs for these projects. The plant gate supply costs, which exclude transportation and blending costs, are C$44.70/bbl for a SAGD project and C$28.66/bbl for an expansion phase of SAGD. A comparison of field gate costs from the February 2017 update with this year’s supply costs indicates that, after adjusting for inflation, the supply cost for a greenfield SAGD producer has not changed significantly, increasing by 1 percent.

After adjusting for blending and transportation, the WTI equivalent supply costs at Cushing are US$60.17/bbl and US$51.59/bbl for a greenfield and expansion SAGD, respectively. A summary of costs is presented in Chapter 2, Table 2.6. At current WTI prices of just above US$66/bbl, these projects are decidedly economic. The relative position of oil sands projects against other crude oils is comparatively competitive, and as oil prices are expected to increase, so will the profitability of oil sands projects. There are risk factors that might affect project economics, such as market access, exchange rate, future oil prices, project costs, etc. Some of these impacts were evaluated through a sensitivity analysis.

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1 Direct cost comparison is not recommended and only shown to illustrate the direction of change. Because some changes were made in the project assumptions regarding carbon policy as well as project economics, a direct comparison of costs is not favoured.

2 At the time of writing, WTI prices traded at US$66.52/bbl.
While capital costs and the return on investment account for a substantial portion of the total supply cost, Alberta stands to gain $4.43 to $7.81 in royalty revenues for each barrel of oil produced on average, over the life of an oil sands project. On a percentage basis, these range from 15.5 to 17.5 percent share of total supply cost.

**Production Forecast – Three Scenarios**

Figure E.2 illustrates the possible paths for production under three scenarios. For an oil sands producer, a project’s viability relies on many factors such as, but not limited to, the demand-supply relationship between production, operating and transportation costs (supply side) and the market price for blended bitumen and SCO (demand).
Total production from oil sands areas totalled 2.77 MMBPD in 2017, comprised of in situ (thermal and cold bitumen) production of 1.51 MMBPD and mining production of 1.27 MMBPD within the boundaries of oil sands areas. Total production in 2016 was 2.54 MMBPD, meaning oil sands production grew 9.2 percent year-over-year. Production from oil sands includes an increasing share of Alberta’s and Canada’s crude oil production. In 2017, non-upgraded bitumen and SCO production made up 61 percent of total Canadian crude production and 82 percent of Alberta’s total production.

In the High Case Scenario, production from mining and in situ projects (thermal and cold bitumen) is set to grow to 3.4 MMBPD by the end of the decade and 5 MMBPD in 2030, peaking at an all-time high of 7.5 MMBPD by 2038. In the Low Case Scenario production rises to 3.1 MMBPD in 2020, 3.4 MMBPD by 2030 and flattens to 4.0 MMBPD by the end of the forecast period. CERI’s Reference Case Scenario provides a base case of the oil sands production. Projected production volume will increase to 3.2 MMBPD by 2020 and 4.1 MMBPD in 2030, peaking at 5.5 MMBPD by 2038.

Figure E.2: Bitumen Production Projections

Source: CERI, CanOils

Bitumen production in CERI’s Reference Case grows by an average annual of approximately 130,000 BPD or just over 3 percent per year. The production level is expected to reach the 3 MMBPD mark by the end of 2018 and continue to grow moderately. The growth rate will be slower in the first half of the forecast period than in the last; in particular, the annual growth rate

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3 Totals may not add up due to rounding. Historical production from the Alberta provincial regulator.
between 2018 and 2028 is 2 percent. In contrast, annual growth rate between 2018 and 2038 is almost double, at 3.76 percent. The slight decline in 2016 is the result of wildfires in northern Alberta that happened mid-2016 affecting oil sands projects. The 2028 estimated drop of 125,000 BPD is due to project’s end date assumption of projects, in this case, it is one of the older oil sands mines coming offline.

**Oil Sands Economic Contribution**

The overall contribution of the Canadian oil and gas industry to the Canadian GDP amounted to $108 billion in 2017 or nearly 6.5 percent share of total Canadian GDP, which is a half percent higher than the 2016 contribution. Oil sands represent a significant portion of the oil and gas sector, bringing in almost half, or $44.2 billion, of the $108 billion.

The industry is projected to contribute $1.4 trillion to the Canadian GDP over the next 10 years. Most of the impact will be felt in Alberta, but Saskatchewan is a growing contributor as more oil sands projects from that province are coming online. Despite a decrease in capital and operating expenditures (which drive the economic impacts modelling), governments will still benefit from tax revenues. Those are estimated to be $139 billion in federal tax revenues and $86.7 billion in provincial taxes over the forecast period.

According to their latest labour outlook, total employment growth in the oil sands sector is expected to be 4,000 jobs by 2021 as companies shift their spending from expansion to maintenance, and repair and optimization of their operations. The total direct employment in the oil sands is forecast to be 32,883 jobs in 2021 (see Figure E.3).

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4 Statistics Canada, CANSIM, Table 379-0031.
5 Base numbers are sourced from CERI Study 166, “Economic Impacts of Canadian Oil and Gas Supply in Canada and the US (2017-2027)”. August 2017. Then adjusted for lower production level.
Figure E.3: Oil Sands Sector Labour Demand (# of jobs)

Source: PetroLMI, CERI

**Emissions**

Figure E.4 illustrates total emissions projection for the **Reference Case** production forecast. The on-site emissions projection includes emissions from existing upgrading, electricity or fugitive emissions and flaring. Current on-site emissions projected to grow from 72 MT/year in 2017 to 103 MT/yr in 2030, breaching the emissions cap of 100 MT. Increasing production in this sector makes meeting international commitments increasingly difficult to achieve, and thus there is interest in reducing the amount of GHGs emitted to extract bitumen from the oil sands and generate synthetic crude oil. In CERI Study 164, the Institute detailed several techno-economic paths on how to grow oil sands production and reduce overall emissions.³

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Figure E.4: Oil Sands Emissions by Project Type

Source: CERI, CanOils
Chapter 1: Introduction

Background
The collapse in oil prices worldwide has affected the industry and slowed the pace of upstream investment around the world – including in heavy crude oil development in Canada. In addition, in 2017, the world witnessed global super-majors departing oil sands by selling off their Canadian assets. However, these departures brought opportunities for Canadian companies to purchase quality assets that have been foreign-owned. These transitions solidified positions of Canadian oil producers for a new wave of growth.

Canada is still among the top five global crude oil producers. Synthetic crude oil (SCO) and bitumen production are expected to grow, albeit at a slower pace. The need for expansion in existing oil pipeline capacity comes at the forefront of challenges that the oil sands industry is facing today, in addition to oil prices. As Western Canadian crude oil production continues to grow, the economic benefits to the nation will depend on the ability to connect this growing supply with downstream demand.

It is also important to stress how some excess capacity is crucial to be able to manage pipeline maintenance times and to provide flexibility for new market development. Constraints in pipeline capacity and the lack of access to existing and new demand centres have deepened the discount between WTI and Western Canadian crudes and hence have had a severe impact on the netbacks realized by Canadian producers. With the ongoing opposition of federally-approved Kinder Morgan’s Trans Mountain pipeline expansion and Enbridge’s Line 3, doubts are mounting as to whether export pipeline capacity will increase by approximately 1 million barrels per day, alleviating some existing constraints in the mid-term. Also, crude by rail still serves markets where pipeline capacity is non-existent or constrained.

On the supply side, because of the rapid growth in American oil production, inland refining markets in the US Midwest (current recipients of most of the Canadian heavy imports) have been flooded with cheap, high quality tight crude oil, which leaves Canadian heavy sour crude oil subject to price markdowns (due to lower quality and bottlenecks in their delivery infrastructure). This situation provides Canadian producers with a financial incentive to expand market access in the United States, Canada, and beyond. It also highlights the risk of overreliance on limited export markets and the need for options.

The US Gulf Coast (USGC) is one of the world’s largest refining centres, and its considerable heavy oil processing capacity presents the largest opportunity for Western Canadian heavy crude oil supply. Canadian heavy crude oil competes for market share in the US Gulf Coast with heavy crude oil from Latin American producers, mainly Mexico, Venezuela, Brazil and Ecuador. Mexico and Venezuela are the main heavy crude oil exporters to the US Gulf Coast, accounting for over 45 percent of total crude oil imports to that region.
Western Canadian production has always had limited access to the USGC market, especially because of the lack of infrastructure connecting Cushing, Oklahoma to refineries in Texas. To support market access to the Gulf Coast, more than 1.2 MMBPD of pipeline capacity from the US Midwest to the Texas Gulf Coast has been installed.

Expansion of pipeline infrastructure and shipping routes to international markets and the US would create opportunities for Canadian oil producers and benefit the Canadian economy. Allocating exports to other markets such as Asia and Europe also reduce dependence on the US market, which used to be Canada’s number 1 customer. Until it became our number 1 competitor.

Although the need to expand and reach new markets for oil sands is pressing, production and pipeline projects associated with oil sands have come under increased scrutiny, contributing to delays and uncertainty. Although not every factor will influence future markets for oil sands, some of the most prominent ones include federal and provincial regulatory processes, local concerns, greenhouse gas emissions and climate change policies, as well as Indigenous People’s rights in Canada.

Production and capital investment forecasts for the oil sands industry are estimated to continue to increase into the future, albeit with some reduction on capital spending in the near term as a result of low crude prices and an overall global economic downturn. The nature of new project development in the oil sands has changed. Ten years ago, the industry was dominated by megaproject mines and upgraders each built by several thousand people. Since then, the sector has transformed into smaller, more manageable in situ projects. Notwithstanding the uncertainties around market access and lower crude oil prices, oil sands production is expected to grow.

If the advantage in tight oil plays goes to companies who move quickly to secure acreage and climb steep learning curves to economic oil production (and the steep downward curve of production decline), then the advantage in the oil sands goes to companies that effectively deliberate over the risks of multi-decade operations. Heavy oil differentials, pipeline capacity limitations and a volatile oil price all play a role in these considerations, but they invariably take a back seat to larger and more global oil supply and demand fundamentals.

Another factor that plays a role in the pace of oil sands development after global and regional supply and demand fundamentals is the provincial and federal governments’ climate change policies – an increased carbon tax and absolute emissions cap in Alberta, federal carbon pricing, and changes to the environmental assessment of major infrastructure projects.

CERI’s oil sands production forecast shows growth of bitumen production over the next 20 years. The plans to expand oil sands production, increase pipeline takeaway capacity and gain access to other markets are still, however, dependent on key elements that must align for the industry. CERI believes these elements are:
i) favourable oil prices at levels where oil sands projects can be economic,
ii) implementing cost-cutting measures through the adoption of improved processes and technologies,
iii) continuous improvement in an environmental performance among oil sands producers,
iv) appropriately managing project planning with a realistic timeline and budget, and
v) the ability to collaborate effectively in a competitive environment.

Approach
Similar to past editions of this report, three scenarios for oil sands developments are explored. In addition, given the assumptions for the current cost structure, an outlook for future supply costs will be provided.

The purpose of this report is to:

- Provide the reader with a better understanding of the current status of Canadian oil sands projects, both existing and planned. The status assessment covers the full spectrum of activities and technologies, such as in situ, mining, and integrated production; and facilities for upgrading crude bitumen to synthetic crude oil (SCO).
- Explore the future direction of oil sands development, including projections of production, investments, operating costs, natural gas, emissions and diluent requirements.
- Estimate the supply cost, including costs associated with carbon emissions, for greenfield projects as well as expansion phases.
- Provide an update on the economic impacts of oil sands development.

CERI’s oil sands projections and supply cost analysis is used by industry, governments, and other stakeholders as part of their market analysis. This report relies upon up-to-date information available on project announcements (updated to the end of 2017), and market intelligence gathered by CERI’s oil sands team.

This year’s report presents project vintages and production capacities of existing and planned projects. Within CERI’s oil sands database, the projects are identified by type (e.g., mining and extraction, in situ, upgrading), location, and extraction technologies (including pilot projects). Similarly, upgrading facilities are characterized by technology, and by type (i.e., stand-alone or integrated with crude bitumen extraction facilities).

All the above information for both existing and future projects is presented at the aggregate industry level (i.e., oil sands industry as a whole) throughout this report. The oil sands projects are classified according to their stage of development.
Organization of the Report
Chapter 1 highlights the background of the study and presents the objective and the scope.

Chapter 2 presents the assumptions and methodology used in the supply cost assessment, followed by results for supply costs and sensitivities.

Chapter 3 highlights the assumptions and methodology used in the oil sands forecasting model and presents scenario-based production projections, followed by projections of capital investment, operating costs, natural gas and diluent demand, emissions and economic impacts for the Reference Case Scenario.
Chapter 2: Oil Sands Supply Costs

Introduction
Oil sands developers and dedicated research and development (R&D) have stimulated the employment of innovative technologies to recover crude bitumen from Alberta’s oil sands resources. The result is a commercially viable industry that effectively competes on the world scale with conventional and other energy sources.

The extraction of Alberta’s oil sands is currently based on two methods: in situ and mining. In situ recovery consists of primary recovery, thermal recovery, solvent-based recovery, and hybrid thermal/solvent processes. Surface mining and extraction could be either a stand-alone mine or integrated with an upgrader. Within in situ and mining methods, various technologies to extract valuable bitumen from the oil sands are utilized. Future R&D will focus on increasing recoverable reserves, reducing costs, improving product quality and enhancing environmental performance. Industry, government and community stakeholders will continue to carry out R&D if there is a perceived commercial incentive to do so. For more information on what technologies and processes are being developed, refer to CERI Study 164.

This chapter discusses CERI’s supply cost methodology and assumptions and presents supply cost results.

Methodology and Assumptions
Supply cost, sometimes referred to as break-even price, is the constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes, and earn an acceptable return on investment. For this study, supply costs are calculated in constant 2017 dollars. CERI has used imperial units of measurement for production volumes and reserves. Oil supply costs and prices are stated in imperial units, either in Canadian dollars per barrel (C$/bbl) or US dollars per barrel (US$/bbl).

CERI’s model solves for a break-even oil price – that is, the oil price that gives a net present value (NPV) of zero – with a real discount rate of 10 percent. The model also has the flexibility to vary inputs, thus allowing for estimation of the supply cost by extraction method required to bring forth new oil sands projects.

Supply costs have been calculated for the raw bitumen at the source field location. To place these values in a market context, supply costs have been calculated in terms of equivalent prices for marketable crude oil (e.g., blended bitumen) at key Alberta market centers (i.e., Hardisty and

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1 Within mining and extraction, various technologies are used to support the extraction process and transportation of oil sands. While each technology has some advantages and disadvantages, they have all been categorized as mining and extraction for this report and are treated as one technology type.
2 The reader is assumed to have some familiarity with each extraction method. Detailed descriptions of the extraction technologies are available from CERI Study 122 and 126.
Edmonton), and in terms of the corresponding equivalent market price of West Texas Intermediate (WTI) crude oil at Cushing, Oklahoma. This required that CERI make several assumptions about market pricing relationships – described later in this chapter.

Although each project is different in its geographical location, quality of reserves and financial structure, this analysis relies heavily on capital and operating cost estimates prepared for a more generic project. Here, CERI evaluates a typical greenfield steam-assisted gravity drainage (SAGD) project, and an expansion of an existing SAGD project, reflecting the changes in the oil sands industry. While significant production comes from integrated mining projects, no new mining projects have been announced; hence the supply cost analysis does not extend to a mining project. The majority of new proposed and announced in situ projects will use SAGD technology or a variation of it, like a hybrid steam/solvent technology. More innovative in situ technologies were evaluated in CERI’s report addressing costs and environmental performances of new processes and technologies.4

Design Assumptions
The Canadian oil sands industry is facing several cost-related and market issues that have affected the economic viability of some oil sands projects. Capital and operating costs play the most important role in determining the supply costs. The assumptions that underpin each project are presented in Table 2.1. The data for capital and operating costs are collected from CanOils database, as well as public sources, such as company annual reports, investor presentations, company announcements, etc., and is averaged across projects according to extraction method. These costs reflect today’s economy and are representative of costs for typical greenfield investment; they do not reflect opportunities for reduced supply costs that are available to industry.

The project design parameters are typical of the industry’s projects that are being built today; a production flow rate of 30,000 BPD is assumed for SAGD projects. The energy requirements have been estimated according to the design parameters and reflect today’s use of natural gas and electricity feedstock. The natural gas requirement for a SAGD plant is 35,910 GJ/d (~2.8 steam to oil ratio or SOR) to reflect recent history – currently, the SOR among SAGD operators varies between 1.5 to 7 barrels of steam per barrel of bitumen, with the bulk of projects operating in the SOR range of 2.5-3 bbl/bbl. It is assumed that in situ projects do not generate any excess electricity and that in situ projects purchase electricity from the provincial grid.5

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5 In situ with co-generation capability is not evaluated.
With oil prices determined in the context of the global market, capital costs are one of only a few parameters operators directly control that have an impact on project economics. Historically, oil sands projects have experienced significant inflationary pressures as projects progressed towards completion. Labour shortages, material scarcity, administrative and engineering delays have all contributed to cost overruns. Capital cost increases ultimately eroded returns for producers. With the downturn in the oil prices globally – 2014-2016 and even into 2017 – capital spending in new projects has experienced a decline, as more projects were being postponed and even cancelled. Nevertheless, a handful of producers are building new projects or expanding existing facilities with expansion phases. The capital cost estimates used in the supply cost calculations are estimates for the projects that are or will be under construction in the 2018-2019 timeframe. The capital requirements range from SAGD expansion phase estimate of $17,000/b/d to a new-build of $65,000/b/d of flowing capacity. In this context, two estimates were taken for supply cost calculations – greenfield project with $40,000/b/d of flowing capacity and an expansion phase with $20,000/b/d of flowing capacity.
The sustaining capital costs reflect sustaining capital requirements that are consistent with the industry estimates: sustaining capital costs are $4.00/bbl of capacity for a greenfield SAGD project and $2/bbl of capacity for an expansion phase.

Total operating costs have been decreasing year-on-year for the majority of existing projects, in situ and mining. The total operating costs for selected projects are shown in Figure 2.1. The sampled operating costs for in situ producers, shown in the top part of Figure 2.1, have declined by 6 percent on average from 2009 to 2016 in real 2017 dollars; for mining producers – the decline of sampled operating costs, shown in the bottom part of the Figure, was not as large as for in situ producers, costs declined by an average of 2 percent from 2009 to 2016 in real 2017 dollars.

Figure 2.1: Total Operating Costs for In Situ and Mining Projects (C$2017/bbl)

Source: CanOils, CERI
The operating cost estimates for supply costs calculation are 2016 costs of existing in situ projects and are assumed to represent operating costs for new projects going forward. The total operating costs and non-energy portion of costs are shown in Table 2.1. The non-energy related portion is about 70 percent of total operating costs.

Oil sands projects are energy-intensive, consuming large quantities of natural gas, electricity, diesel and chemicals, which are often purchased on the market and hence the energy-related portion of operating costs is very dependent on the prices of natural gas, electricity and other products used as an energy feedstock. To approximate the energy-related portion of operating costs for an in situ producer, natural gas and electricity prices are used together with their consumption.

While research continues on finding ways to use less natural gas, it is still the primary fuel source for the oil sands industry. Hence, the cost of gas is important and has become a significant component of the total supply cost framework. To approximate the cost of natural gas purchases, a forecast of Henry Hub natural gas prices was obtained from the US EIA’s Annual Energy Outlook (AEO) 2018 for the period 2016 to 2050. Prices were then transformed to 2017 dollars and converted to AECO-C basis gas prices to reflect better the actual cost paid by producers for natural gas. CERI used an AECO-C/Henry Hub differential of US$1.25/MMBTU, and a field premium of C$0.27/GJ. In reality, in situ producers would utilize the associated natural gas that is produced (not all in situ projects have an associated gas production), and might not be purchasing the full volume that is required, and hence, the overall cost for natural gas might be lower. For supply cost purposes, however, it is assumed that producers purchase natural gas from the market.

Figure 2.2 displays field prices paid by oil sands producers. Since 2010, natural gas prices have been bouncing in the range between $2 and $4/GJ. Since 2014, with the oil price decline, gas prices followed suit. Over the long term, prices are estimated to increase to a sub $5/GJ mark in real 2017 dollars, growing at 2 percent between 2017 and 2049.
Another significant input to oil sands operations is electricity. Prices play a key role in determining the cost of electricity as feedstock to oil sands projects. The 2017 Alberta average hourly pool price was $22.19/MWh.\textsuperscript{6} Due to low natural gas prices in the province, Alberta is currently experiencing historically low electricity prices. It is expected that, in the future, electricity rates will be higher as the province transitions to a cleaner grid by retiring its coal power plants and adding 30 percent or more of renewable generation options as directed by the Alberta Climate Leadership Plan. The main challenge for Alberta’s electricity sector is ensuring sufficient reliable capacity is available to satisfy the electricity demand upon the retirement of coal-fired generating units by 2030.\textsuperscript{7} These changes together with a higher carbon tax indicate an increase in electricity prices in Alberta.

To estimate the cost of electricity for supply cost calculations, the 2017 Alberta average hourly pool price (CAD$/MWh) was used and inflated at an annual inflation rate (i.e., in real terms prices are forecast to remain flat). This forecast is not reflective of Alberta pool prices and considers a possibility of increased use of cogeneration for in situ projects, which would lower the overall energy-related portion of the operating costs. Over the next decade, it is probable that in situ projects will move towards cogeneration, with units sized to match a projects’ steam and electricity load or potentially even sell the excess electricity to the provincial grid.


For the purposes of calculating supply costs, in situ projects are assumed to purchase electricity from the Alberta grid at the current low level of prices. Figure 2.3 illustrates the electricity price forecast.

**Figure 2.3: Electricity Price Forecast (C$2017/MWh)**

![Electricity Price Forecast Graph](image)

Source: AESO, CERI

**Light-Heavy Differential**

To place oil sands supply costs of a barrel of bitumen in a market context, they have been calculated in terms of equivalent prices for marketable crude oil (e.g., blended) at key Alberta market centers (i.e., Hardisty and Edmonton), and in terms of the corresponding equivalent market price of WTI crude oil at Cushing, Oklahoma. This required CERI to make a number of assumptions about market pricing relationships. Of particular importance is the light-heavy differential, specifically the differential between light WTI and heavy WCS.

All crude oil is not valued equally. A light oil that is low in sulphur content (i.e., sweet) is more valuable to refiners than heavy oil with higher sulphur content (i.e., sour), because it is less energy-intensive to refine light sweet crude, and the resulting petroleum products are of higher quality. Thus, refining heavy sour grades require more complex refining operations. The market value of each crude stream, therefore, reflects the crude characteristics as well as the refined products yield from such crude. The price difference between a barrel of light sweet oil and a barrel of heavy sour oil represents the light-heavy or quality price differential.
Two of the most important physical crude qualities are density (as measured by API gravity) and sulphur content. Figure 2.4 illustrates those characteristics for various crudes from around the world (including various pricing benchmarks) and places Canadian crudes in the context of crude oil quality. It becomes very clear that bitumen-derived crudes measure high in sulphur content and low on gravity as compared to some other crudes.

**Figure 2.4: Densities and Sulfur Content of Crude Oils**

Source: BP, EIA, Genesis Capital, Oil & Gas Journal, Pemex, Statoil

Almost all the Canadian crude oil exports are transported to refineries in Canada and the US with the largest share originating in Alberta. The two main distribution hubs in Alberta are located near Edmonton and Hardisty – the price point for WCS as a heavy crude benchmark. Launched in 2004 by Encana Corporation (now Cenovus Energy), Canadian Natural Resources Limited, Talisman, and Petro-Canada (now Suncor), the WCS is a blend of conventional Western Canadian crudes.
heavy oil and crude bitumen that has been blended with sweet SCO and diluents. Table 2.2 compares the characteristics of the WCS blend with two other heavy crude oils. Currently, WCS prices are closely linked to WTI because the majority of WCS crude is shipped to the US Midwest market, for which the historical benchmark has been WTI. WCS crude is sold at a discount to WTI because it is a lower quality crude, producing a positive light-heavy differential.

Table 2.2: Crude Oil Characteristics

<table>
<thead>
<tr>
<th></th>
<th>WCS Target</th>
<th>Maya</th>
<th>Mars</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity (API°)</td>
<td>19-22</td>
<td>21.8</td>
<td>30.4</td>
</tr>
<tr>
<td>Carbon Residue (Wt %)</td>
<td>7.0-9.0</td>
<td>13</td>
<td>5.5</td>
</tr>
<tr>
<td>Sulphur (Wt %)</td>
<td>2.8-3.2</td>
<td>3.5</td>
<td>1.9</td>
</tr>
<tr>
<td>TAN (mo KOH/g)</td>
<td>0.7-1.0</td>
<td>0.3</td>
<td>0.68</td>
</tr>
</tbody>
</table>

*TAN – Total Acid Number, measured in mg of potassium hydroxide needed to neutralize one gram of oil.


Maya is considered close in quality to WCS, yet Maya is a waterborne crude with readily available access to US Gulf Coast refiners and represents the potential price/market WCS producers could realize/access. Historically, Maya traded at a premium to WCS. Mars is a medium sour benchmark in the US, and produced offshore Gulf of Mexico, 130 miles from the coast. It is of a higher quality than Maya and WCS but has a relatively high sulphur content in comparison to other medium to medium-heavy crudes.

As the US tight oil production rose, flooding the US with extra crude supply and squeezing the outflow pipeline capacity in the Cushing, Oklahoma hub, the price for WTI at the hub, which had historically run in close parity with an international benchmark, North Sea Brent, became depressed and started to disconnect from the global benchmark. Discounts deepened, affecting essentially all inland lower-48 crude grades, as well as WCS (since it is priced off WTI). Since January 2011, these discounts have been steep and have been considered ‘structural’ as seen in Figure 2.5. Since the reversal of the Seaway pipeline and construction of the southern leg of the Keystone XL in 2013 to connect Cushing to the Gulf of Mexico, WTI prices have increased, narrowing the differential between Brent and WTI, but not near its historical norm of US$2-5/bbl, 8

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8 While WCS or dilbit is a blend of bitumen, conventional and synthetic crudes, its main crude quality parameters (both API gravity and sulfur content) are very similar to those of other western Canadian conventional heavy sour blends such as Lloyd Blend, Bow River, and other heavy sour conventional blends produced in Alberta and Saskatchewan. Cold Lake Blend is another dilbit blend that trades in large volumes. Other dilbits include Access Western Blend, Borealis Heavy Blend, Christina Dilbit Blend, Peace River Heavy, Seal Heavy, Statoil Cheecham Blend, and Wabasca Heavy (see: http://crudemonitor.ca/home.php)


10 Another example is WTI versus Light Louisiana Sweet (LLS), a coastal crude, which prior to 2011 traded at $1/bbl discount to WTI but has recently traded at $24/bbl premium to WTI.
potentially indicating two things: either the two markets are no longer correlated and prices are representative of regional markets only or the market to market connectivity is not sufficient to increase WTI prices to Brent levels (sans transportation costs) or a combination of both.

Besides the lack of appropriate pipeline capacity between the US markets, the problem is further exacerbated by the lack of export pipeline capacity from Western Canada to the US, thus depressing WCS prices against WTI and other crudes, like Mexican Maya. Maya is considered close in quality to WCS, yet Maya is a waterborne crude with readily available access to US Gulf Coast refiners and represents the potential price/market WCS producers could realize/access. Historically, WCS has tended to trade at a discount to Maya, averaging an annual discount of US$6.50/bbl between 2005 and 2010, but the differential started to widen and reached as much as US$48/bbl in February 2013. Recently, with rail bringing in more crude from Canada to the Gulf, that differential narrowed again.

Since the launch of WCS, the price has been tracking the movements of WTI closely with periodic fluctuations. In turn, the differential between WTI and WCS has fluctuated from a low of just under US$6/bbl in April 2009 to a high of US$37/bbl in February 2013, and more recently US$27.20/bbl in March 2018 with an average differential for 2017 at about US$12/bbl. In the first three months of 2018, it ballooned to US$27.20/bbl.

The data series for WCS prices comes from the Baytex Energy website, while Brent and WTI prices are sourced from the US EIA from January 2005 to March 2018. Figure 2.5 illustrates the selected historical benchmark price series and WTI-WCS differential.

While the WTI-WCS differential has been much discussed and pondered upon by media, industry and government, empirical evidence shows that the differential fluctuates over time, that is, it narrows and widens based on market conditions. While this fluctuation is hard to estimate in the long-term, the data support an assumption of a long-term average WTI-WCS differential of US$15/bbl. Therefore, based on the historical data, the light-heavy differential (not including transportation costs) is assumed to be constant at US$15/bbl. Over time as more blended bitumen and SCO continue to penetrate existing as well as new markets such as the US Gulf Coast and markets outside of North America, the light heavy differential might narrow in the future to just a quality-based.

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11 Maya has in turn historically traded at a US$7-9/bbl discount to WTI reflecting mainly quality differences. On the other hand, Maya has historically traded at a $10/bbl discount to Light Louisiana Sweet (LLS), which further reflects the light-heavy differential in the coastal area (more reflective of a global light-heavy differential).
12 http://www.baytexenergy.com/operations/marketing/benchmark-heavy-oil-prices.cfm
Crude Oil Transportation Costs

The supply cost is calculated for raw crude bitumen produced in the field. This bitumen supply cost is converted to prices of marketable blended bitumen at key Alberta market centres (Edmonton and Hardisty), and to an equivalent market price of WTI crude oil at Cushing, Oklahoma. For non-integrated projects, blending costs are estimated through accounting for the volume of diluent required per barrel to bring the bitumen blend to a density that meets pipeline specifications, the cost of diluent, and the cost of transporting diluent to the field. Based on recent industry data, a 5 percent premium for a diluent cost above WTI price has been removed, given the increased supply of condensate from domestic sources and pipeline imports from the US. Transporting the blend from the field to Hardisty is assumed to be C$1.00 per barrel. Transportation costs from Hardisty to Cushing have been adjusted upward to US$5.25 per barrel.13 Per barrel transportation costs from the field to Hardisty, and Edmonton to Cushing, Oklahoma, are assumed to rise at an annual inflation rate of 2.0 percent.

The transportation cost assumptions above are based on pipeline transportation costs. Alternatively, it is possible for bitumen and its blends to be transported via rail to destined export markets. Rail transportation costs have historically been higher than those of pipeline, but continued market access and pipeline logistics constraints increased the use of ‘crude-by-rail’ among producers. In January 2018, Canadian producers shipped 145 MBPD, a 20 percent increase from January 2017.

Rail also offers optionality on what is shipped, the coil and insulated (C&I) rail cars can transport bitumen with little or zero need for diluent. In comparison, diluted bitumen or dilbit via rail would use the same amount of diluent as dilbit in pipelines or around 30%. Railbit will require about 17% diluent and cleanbit would require no diluent at all. As current pipeline constraints persist, widening the differential between WCS and WTI, rail can increase its crude-by-rail rates, but both Canadian railway companies, CN and CP, demand long-term take-or-pay contracts and higher rates to add locomotives and train crews to move oil because they fear the business will evaporate once new export pipelines come on stream.¹⁴

According to Transportation Safety Board of Canada (TSB) data,¹⁵ there has been on average 66 rail incidents over the 2008-2016 period with a release of 200 or more litres (~1.3 barrels) of “low vapour pressure flammable liquids”¹⁶ (Figure 2.7). The largest number of incidents happened in the 2013-2014 period. After the Lac-Mégantic, Quebec tragedy, various safety regulations were enforced on rail transportation of hydrocarbon liquids, and as a result, the number of incidents in the rail industry with dangerous flammable goods has decreased by three times. The ratio of goods moved to the number of incidents per year has increased from 1,759 thousand barrels in

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¹⁶ As the TSB does not specify the type of goods involved, these 66 incidents would include all flammable products: gasoline and aviation turbine fuel, fuel oils and crude petroleum, gaseous hydrocarbons, including liquid petroleum gas (LPG’s), and other refined petroleum and coal products.
2013 to 5,137 thousand barrels for rail in 2016, but still falls much behind pipelines performance with 221,227 thousand barrels for 2012 and 1,401,973 thousand barrels for 2016.

**Figure 2.7: Pipeline and Rail Crude Shipment Incidents**

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### Economic and Taxation Assumptions

#### Rate of Return

The supply cost estimates presented in this study have been calculated using cash flow models similar to those used by industry and governments. The costs have been calculated using an annual discount rate of 10 percent (real). This is equivalent to an annual return on investment of 12.0 percent (nominal) based on the assumed average inflation rate of 2.0 percent per annum. Companies may evaluate individual investments using higher discount rates; these would translate to higher supply costs than those presented here.

Within the supply cost model, federal and provincial corporate income taxes have been assumed constant at 15 percent\(^\text{17}\) and 12 percent,\(^\text{18}\) respectively.

#### Capital Depreciation

Currently, most machinery, equipment and structures used to produce income from an oil sands project, including buildings and community infrastructure related to worker accommodations, are eligible for a capital cost allowance (CCA) rate of 25 percent under Class 41 of Schedule II to

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\(^{17}\) Effective January 1, 2012, the federal rate dropped to 15 percent from 16.5 percent.

\(^{18}\) Effective July 1, 2015, the provincial corporate rate increased from 10 to 12 percent.

the Income Tax Regulations. In addition to the regular CCA deduction, an accelerated CCA has been provided since 1972 for assets acquired for use in new mines, including oil sands mines, as well as assets acquired for major mine expansions (i.e., those that increase the capacity of a mine by at least 25 percent). In 1996, this accelerated CCA was extended to in situ oil sands projects. This change ensured that both types of oil sands projects are accorded the same CCA treatment.

The accelerated CCA takes the form of an additional allowance that supplements the regular CCA claim. Once an asset is available for use, the taxpayer is entitled to deduct CCA at the regular rate. The additional allowance allows the taxpayer to deduct up to 100 percent of the remaining cost of the eligible assets, not exceeding the taxpayer's income for the year (calculated after deducting the regular CCA). This accelerated CCA provides a financial benefit by effectively deferring taxation until the cost of capital assets has been recovered from project earnings.

This incentive helped to offset some of the risk associated with early investments in the oil sands and contributed to the development of this resource. Over time, however, technological developments and changing economic conditions have led to major investments that have moved the sector to a point where the majority of Canada's oil production will soon come from oil sands. As a result, this preferential treatment is no longer required. Budget 2007 phased out the accelerated CCA for oil sands projects – both mining and in situ. The regular 25 percent CCA rate will remain in place. To provide stability, and in recognition of the long lead time involved in some oil sands projects, the following transitional relief was provided:

- the accelerated CCA will continue to be available in full for:
  - assets acquired before March 19, 2007, and
  - assets acquired before 2012 that are part of a project phase on which major construction began before March 19, 2007
- for other assets, the additional accelerated allowance will be gradually phased down over the period 2011 to 2015 (when it will be eliminated), according to the schedule set out below.

The percentage allowed will decline each calendar year, as shown in Table 2.3 (prorated for off-calendar taxation years).

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19 Property acquired by a taxpayer for the purpose of gaining or producing income from a bituminous oil sands project in Canada will generally be included in Class 41.  

19 To the extent that the accelerated CCA for oil sands projects induces incremental oil sands development that could contribute to environmental impacts such as greenhouse gas emissions, air and water contaminants, water usage, and disturbance of natural habitats and wildlife, these changes could help reduce such incremental impacts.
Table 2.3: Phase-Out Schedule

<table>
<thead>
<tr>
<th>Year</th>
<th>Allowable % of Additional Allowance</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>100</td>
</tr>
<tr>
<td>2011</td>
<td>90</td>
</tr>
<tr>
<td>2012</td>
<td>80</td>
</tr>
<tr>
<td>2013</td>
<td>60</td>
</tr>
<tr>
<td>2014</td>
<td>30</td>
</tr>
<tr>
<td>2015</td>
<td>0</td>
</tr>
</tbody>
</table>


For the purposes of this report, it is assumed that the transitional relief is not applicable for the supply cost calculation of our greenfield projects and hence the phase-out schedule is applied as set in Table 2.3.

Oil sands operations are assumed to commence construction on January 1, 2018, and begin operating on January 1, 2020. The projects will continue to operate until the end of 2049, based on a 30-year project life.

**Carbon Tax**

In 2016, the Alberta Government enacted changes to its carbon policy. The new Climate Leadership Plan is a strategy to reduce emissions while diversifying the provincial economy. Several key aspects include:

- implementing an economy-wide carbon price on greenhouse gas emissions;
- retiring coal-generated electricity by 2030;
- developing more renewable energy;
- capping oil sands emissions to 100 megatonnes per year
- reducing methane emissions by 45% by 2025.

Alberta will implement a $30/tonne carbon price for oil sands facilities to drive towards reduced emissions. A legislated maximum emissions limit of 100 Mt per year, with provisions for cogeneration and new upgrading capacity, will help drive technological progress. The carbon price started at $20/tonne of CO2eq on January 1, 2017 and increased to $30/tonne on January 1, 2018. Post-2018, the federal carbon tax assumption is adopted.\(^{21}\) The federal carbon tax will be $40/tonneCO2eq in 2021 and increase to $50/tonne in 2022 and subsequent years.

On January 1, 2018, the Carbon Competitiveness Incentive (CCI) regulation replaced the Specific Gas Emitters Regulation (SGER). Similar to SGER, the CCI regulation applies to facilities that emitted 100,000 tonnes or more of greenhouse gases in 2003, or a subsequent year. Facilities that emit less than 100,000 tonnes have a choice to opt-in according to guidelines provided in the Regulation document. The new policy prescribes product-specific emission performance standards or benchmarks that replace the past uniform intensity-based reduction approach. This replaces the existing intensity targets, which are based on GHG reductions per unit of production regardless of the type of product. Access to flexibility mechanisms (such as the ability to purchase Alberta-based offsets or pay into the existing technology fund in lieu of reducing operational emissions) is expected to continue to be a compliance option for large emitters.

CERI’s supply cost model incorporates the newly established benchmarks for oil sands production. While there are options that a producer can exercise to comply with the policy, the model assumes that a producer pays the carbon tax on emissions above the established benchmarks. The benchmarks are shown in Table 2.4.

### Table 2.4: Established Benchmarks for Oil Sands Production

<table>
<thead>
<tr>
<th>Year</th>
<th>In Situ Bitumen</th>
<th>Mining Bitumen</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>tonnesCO2eq./m³</td>
<td>kgCO2eq./bbl</td>
</tr>
<tr>
<td>2018</td>
<td>0.3504</td>
<td>55.7075</td>
</tr>
<tr>
<td>2019</td>
<td>0.3504</td>
<td>55.7075</td>
</tr>
<tr>
<td>2020</td>
<td>0.3469</td>
<td>55.1510</td>
</tr>
<tr>
<td>2021</td>
<td>0.3434</td>
<td>54.5946</td>
</tr>
<tr>
<td>2022</td>
<td>0.3399</td>
<td>54.0382</td>
</tr>
<tr>
<td>2023+</td>
<td>BE=BEY-1 - 0.0035</td>
<td>BE=BEY-1 - 0.5564</td>
</tr>
</tbody>
</table>

Note: The values in the rows for 2020, 2021 and 2022 reflect the application of an annual 1% tightening rate. BE is established benchmark for the year. BEY-1 is established benchmark for the previous year.

Source: Alberta Government. “Carbon Competitiveness Incentive Regulation”. CERI converted the unit from tonnes CO2eq./m³ of bitumen to kgCO2eq./bbl of bitumen.

The benchmarks are based on existing best performers’ emission profiles, i.e., benchmarks equal to the lowest facility production-weighted emission intensity in the sector. For example, the established benchmark for in situ bitumen of 0.3504 tonnes CO2eq./m³ (or 55.71 kgCO2eq./bbl) of bitumen for the 2018-2019 period translates to a project with a SOR of approximately 2-2.3. Currently, projects’ emissions per barrel vary from low to high levels. Figure 2.8 illustrates historic emission intensities for selected projects from 2009 to 2015.

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22 For more information on the Regulation: [https://www.alberta.ca/carbon-competitiveness-incentive-regulation.aspx](https://www.alberta.ca/carbon-competitiveness-incentive-regulation.aspx)
Figure 2.8: Emission Intensities by Project (kgCO2eq./bbl bitumen)

Table 2.5 below presents the average change in emissions intensity for mining and SAGD production. Mining emissions intensity has improved by an annual average of 4% from 2009 to 2015. SAGD production emissions intensity improvements have averaged 1.4% over the same period.

Table 2.5: Annual Emissions Intensity for Bitumen Production, 2009-2015

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>SAGD Avg</td>
<td>94.65</td>
<td>84.31</td>
<td>82.56</td>
<td>81.73</td>
<td>83.20</td>
<td>82.00</td>
<td>85.67</td>
<td>-1.4%</td>
</tr>
<tr>
<td>Mining Avg</td>
<td>36.65</td>
<td>37.09</td>
<td>37.04</td>
<td>35.35</td>
<td>32.19</td>
<td>31.86</td>
<td>29.04</td>
<td>-4.0%</td>
</tr>
</tbody>
</table>

Royalty Assumptions
The Alberta oil sands royalty regime is based on the net revenue system whereby the oil sands producer pays a lower royalty rate based on gross revenues until the point at which the producer has recovered all the allowed project costs (those incurred up to three, and in some cases up to five, years prior to the approved effective date) plus a return allowance based on current Long-Term Government Bond Rates (LTBR) issued by the Government of Canada (floor risk). After payout has been achieved, the project proponent pays the higher of gross revenue royalties based on a gross revenue royalty rate or net revenue royalties based on a higher net revenue royalty rate. Prior to 2009, the rates were fixed at 1 percent of gross revenues (pre-payout) and 25 percent of net revenues (post-payout). After 2009, royalty rates are calculated based on the Canadian dollar price of a barrel of WTI and are fixed at a floor of 1 percent (gross) and 25 percent

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23 Assumed to be 2.4 percent.
(net) when the price is below C$55/bbl, increasing linearly to a ceiling of 9 percent (gross) and 40 percent (net) when the price of WTI is above C$120/bbl as shown in Figure 2.9.

The gross revenue of the project is defined as the revenue collected from the sale of oil sands products (or the equivalent fair market value) less the costs of any diluents contained in any blended bitumen sold. Allowed costs are those incurred by the project operator to carry out operations, and to recover, obtain, process, transport, or market oil sands products recovered, as well as the costs of compliance with environmental regulations and with the termination of a project, abandonment and reclamation of a project site.24

**Figure 2.9: Alberta Bitumen Royalty Rates**

Source: CERI

**Oil Prices**

Turning to the oil price projection, a distinct set of drivers will determine futures prices in the medium- and long-term. Short- to medium-term prices are primarily dependent on expectations of supply and demand balances (measured by the global stock changes), but they are also impacted by factors such as geopolitics, speculation and overall market sentiment. Contrary to this, in the long-term prices are mostly driven by the cost factors of producing a marginal barrel. In this case, a rising marginal barrel cost is expected as a result of increasingly complex supply developments, such as oil sands projects, tight oil plays in more complex geological structures, deep-water and potentially Arctic fields. On the other hand, the drive for more efficiencies and innovative technology will partially limit the rise in exploration and production (E&P) costs.

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To better understand this year’s supply cost results, an oil price projection was required. The forecast of the WTI price was obtained from the EIA’s AEO 2018, for the period 2016 to 2050. Prices were adjusted to constant 2017 dollars and converted to Canadian dollars as shown in Figure 2.10. Since the summer of 2014, when crude markets experienced a major decline in oil prices as a result of burgeoning supply, prices started to increase as the market fundamentals are coming into balance and crude inventories have started to get depleted. The Organization of Petroleum Exporting Countries (OPEC) and non-OPEC production cuts which started late 2016 took some time to show up in the supply/demand numbers, but later in 2017 helped to push up crude prices as crude inventories started to fall. At its annual November 2017 meeting, OPEC extended the supply deal in place through the end of 2018 and placed additional caps on Libyan and Nigerian production. This decision and evidence of compliance have since supported prices at their highest levels all year. With world oil prices now back in the mid-$60s and exporter revenue increasing, there is less pressure on OPEC members to cheat on the deal.

Prices in the near term (insert graph in Figure 2.10) will be around C$60-$65/bbl, before increasing to C$80/bbl at the end of the decade. Over the forecast period of 2018 to 2050 real prices will grow at 2.5%, reaching almost C$140/bbl by 2050.

**Figure 2.10: WTI Price Forecast (CDN$2017/bbl)**

![WTI Price Forecast Graph](image)

Source: EIA, CERI

**US-Canadian Exchange Rate**

Since the summer of 2014, the price of oil has plummeted to its lowest point in years – and so has the Canadian dollar, continuing an ongoing debate on how closely the two are related. Canada’s dollar is often viewed as a petrocurrency because its movements often track oil prices (see Figure 2.11). In simple terms, a petrocurrency is a currency of an oil-producing country —
such as Canada — whose oil exports as a share of total exports are sufficiently large enough that the currency’s value rises and falls along with the price of oil. In other words, a petrocurrency appreciates when oil prices rise and depreciates when oil prices fall.

The most recent 50 percent decline in oil prices in summer 2014 coincides with the depreciation of the Canadian dollar. Given the oil price forecast and high correlation factor between the exchange rate and oil prices,25,26 an exchange rate of US/CDN$0.80 will be assumed in the supply cost calculation. This represents a 20 percent drop from previous assumptions of parity between the two currencies.

**Figure 2.11: CDN/US Exchange Rate**

Source: EIA, Bank of Canada

**Supply Cost Results**

Based on these assumptions, the supply costs of crude bitumen for a greenfield SAGD and an expansion phase SAGD have been calculated. Figure 2.12 illustrates the supply costs for these projects. The plant gate supply costs, which exclude transportation and blending costs, are C$44.70/bbl for a SAGD project and C$28.66/bbl for an expansion phase of SAGD. A comparison27 of field gate costs from the February 2017 update with this year’s supply costs indicates that,

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27 Direct cost comparison is not recommended and only shown to illustrate the direction of change. Because some changes were made in the project assumptions regarding carbon policy as well as project economics, a direct comparison of costs is not favoured.
after adjusting for inflation, the supply cost for a greenfield SAGD producer has not changed significantly, increasing by 1 percent.

**Figure 2.12: Total Field Gate Bitumen Supply Costs**

![Chart showing total field gate bitumen supply costs](chart)

<table>
<thead>
<tr>
<th></th>
<th>SAGD 10% ROR (a)</th>
<th>Expansion SAGD 10% ROR (a)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fixed Capital (Initial &amp; Sustaining)</strong></td>
<td>$19.33</td>
<td>$9.67</td>
</tr>
<tr>
<td><strong>Operating Working Capital</strong></td>
<td>$0.41</td>
<td>$0.21</td>
</tr>
<tr>
<td><strong>Fuel (Natural Gas)</strong></td>
<td>$4.57</td>
<td>$4.57</td>
</tr>
<tr>
<td><strong>Other Operating Costs (incl. Elec.)</strong></td>
<td>$9.02</td>
<td>$7.65</td>
</tr>
<tr>
<td><strong>Royalties</strong></td>
<td>$7.81</td>
<td>$4.43</td>
</tr>
<tr>
<td><strong>Income Taxes</strong></td>
<td>$2.87</td>
<td>$1.45</td>
</tr>
<tr>
<td><strong>Emissions Compliance Costs</strong></td>
<td>$0.67</td>
<td>$0.67</td>
</tr>
<tr>
<td><strong>Abandonment Costs</strong></td>
<td>$0.03</td>
<td>$0.01</td>
</tr>
</tbody>
</table>

*Return on capital included.

Source: CERI

After adjusting for blending and transportation, the WTI equivalent supply costs at Cushing are US$60.17/bbl and US$51.59/bbl for a greenfield and expansion SAGD, respectively. A summary of costs is presented in Table 2.6. At current WTI prices of just above US$66/bbl, these projects are decidedly economic. The relative position of oil sands projects against other crude oils is comparatively competitive, and as oil prices are expected to increase, so will the profitability of

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*At the time of writing, WTI prices traded at US$66.52/bbl.*
oil sands projects. There are risk factors that might affect project economics, such as market access, exchange rate, future oil prices, project costs, etc. Some of these impacts were evaluated through a sensitivity analysis in the next section.

Table 2.6: Supply Costs Summary

<table>
<thead>
<tr>
<th>Supply Cost</th>
<th>SAGD 10% ROR (a)</th>
<th>Expansion SAGD 10% ROR (a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Present Value (C$ Millions)</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Discount Rate</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Base Year</td>
<td>2017</td>
<td>2017</td>
</tr>
<tr>
<td>Costs (C$/b)</td>
<td>Discounted</td>
<td>Discounted</td>
</tr>
<tr>
<td>Return on Investment</td>
<td>Included</td>
<td>Included</td>
</tr>
<tr>
<td>Fixed Capital (Initial &amp; Sustaining)</td>
<td>$19.33</td>
<td>$9.67</td>
</tr>
<tr>
<td>Operating Working Capital</td>
<td>$0.41</td>
<td>$0.21</td>
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<tr>
<td>Income Taxes</td>
<td>$2.87</td>
<td>$1.45</td>
</tr>
<tr>
<td>Emissions Compliance Costs</td>
<td>$0.67</td>
<td>$0.67</td>
</tr>
<tr>
<td>Subtotal</td>
<td>$44.70</td>
<td>$28.66</td>
</tr>
<tr>
<td>Electricity Sales</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Subtotal</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Total Supply Cost (C$/b)</td>
<td>$44.70</td>
<td>$28.66</td>
</tr>
<tr>
<td>Blend Product @ Hardisty in C$/b</td>
<td>$49.90</td>
<td>$39.17</td>
</tr>
<tr>
<td>Blend Product @ Hardisty in US$/b</td>
<td>$39.92</td>
<td>$31.34</td>
</tr>
<tr>
<td>Blend Product’s WTI Equivalent @ Edmonton in US$/b</td>
<td>$54.92</td>
<td>$46.34</td>
</tr>
<tr>
<td>WTI Equivalent (US$/b)</td>
<td>$60.17</td>
<td>$51.59</td>
</tr>
</tbody>
</table>

Source: CERI

The resulting impact on the overall cost of an oil sands project broken down by percentage share is shown in Figure 2.13. It is assumed that emission compliance costs are royalty deductible, as is currently the case. While capital costs and the return on investment account for a substantial portion of the total supply cost, the province stands to gain $4.43 to $7.81 in royalty revenues for each barrel of oil produced on average, over the life of an oil sands project. On a percentage basis, these range from 15.5 to 17.5 percent share of total supply cost (see Figure 2.13).
Figure 2.13: Oil Sands Supply Costs – Reference Case Scenario (% Contribution)

Source: CERI

Supply Cost Sensitivities
The presented costs for oil sands projects also need to be analyzed in terms of how sensitive costs are to changes to some of the input variables. The ranges used for sensitivities are summarized in Table 2.7.
Table 2.7: Assumptions for Sensitivity Analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Sensitivity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Capital Cost</td>
<td>+/-25%</td>
</tr>
<tr>
<td>Sustaining Capital Cost</td>
<td>+/-25%</td>
</tr>
<tr>
<td>Non-Energy Operating Costs</td>
<td>+/-25%</td>
</tr>
<tr>
<td>Discount Rate</td>
<td>+/-2%</td>
</tr>
<tr>
<td>SOR</td>
<td>+/-25%</td>
</tr>
</tbody>
</table>

Source: CERI

Bitumen supply cost sensitivities for a greenfield SAGD and an expansion phase SAGD are represented graphically in Figures 2.14 and 2.15.

Figure 2.14: Supply Cost Sensitivity – 30 MBPD SAGD Project

The results indicate that SAGD supply cost is the most sensitive to changes in the initial capital expenditures and the assumed discount rate, SOR is another factor that impacts the supply costs. If initial capital is 25 percent higher than the original estimate, the field-gate supply cost rises to $50.81/bbl from $44.70/bbl, in contrast, supply cost decreases to $39.09/bbl if initial capital is 25 percent lower. If the discount rate is raised to 12 percent real, the supply cost is estimated to increase by $5.79/bbl and when it is decreased to 8 percent real, the cost will decrease by $4.92/bbl from its base of $44.70/bbl.
For an expansion phase SAGD, the supply cost will increase to $31.80/bbl and decrease to $25.52/bbl if the initial capital cost increases or decreases by 25 percent, respectively. The discount rate increase to 12 percent will increase the supply cost by $2.55/bbl and a decrease to 8 percent will result in a $2.54/bbl drop in the base supply cost of $28.66/bbl.
Chapter 3: Oil Sands Projections

Based on the supply cost results and given the oil price forecast, the last chapter concluded that greenfield SAGD and expansion phase SAGD oil sands projects are economic. The past mega-large projects like open-pit mines are no longer the trend forward, development of additional phases to existing brownfield facilities cost less than greenfield development and are seen as a way to future growth. Low oil prices have caused companies to announce capital spending cuts, the exchange rate to drop and operating costs to fall. However, an improvement in oil prices in the latter part of this decade indicates that oil sands projects present a profitable long-term investment. This does not imply that every oil sands project will move from concept to reality. Nor does it imply that every oil sands project should go forward. Inevitably, some projects will experience delays for a variety of reasons, including but not limited to those related to financing and transportation and environmental performance.

This chapter presents CERI’s view of where oil sands production might be heading. A discussion of the methodology used to develop the projections is followed by the assumptions used to delay or cancel oil sands projects. CERI’s oil sands projections for bitumen, SCO, natural gas requirements, strategic and sustaining capital, operating costs, and emissions are then provided. Special focus is given to the Reference Case Scenario and discussed in more detail at the end of the chapter.

Methodology and Assumptions
CERI’s methodology for projecting bitumen and SCO production remains unchanged from past reports. Projections are based on the summation of existing and new projects, with a variety of assumptions pertaining to the project schedule and delays, technology, and state of development. The method by which projects are delayed, or the rate at which production comes on-stream, is based upon CERI’s understanding of oil market dynamics and specific characteristics of oil sands projects.

The scenarios are the Reference Case, High Case, and Low Case. The Reference Case incorporates existing and future oil sands project developments subject to two constraints: project startup delays, and capacity curtailments. The Low Case scenario assumes lower bitumen production growth relative to the Reference Case. The growth rate in bitumen production incorporated into the Low Case is half of the average annual growth rate in the Reference Case. The High Case scenario assumes higher bitumen production growth relative to the Reference Case with a growth rate approximately 1.5 times higher than the growth rate in the Reference Case.

Delay Assumptions
On-stream projects are assumed to be in production until the end of the project (unless new phases were added); projects that are under construction will proceed with minimal delays and reach their nameplate capacity. Projects further along the regulatory process are given shorter
delays and have higher probabilities of proceeding to their announced production capacity. Given the current economic downturn, projects that have been announced, but have not yet entered the regulatory process with a disclosure document are given the longest delays.

Delays and probabilities, as measured by a probability fraction, for each phase of the regulatory approval process, are based upon reasonable estimates of the length of time each phase could take. As compared to delay years and capacity curtailments of last year’s update, this year sees an increase in the number of delay years for some categories and a decrease in probabilities of reaching full capacity. Another factor that is contributing to this increase in delays and capacity curtailments is that existing export pipeline capacity is not sufficient to transport the incremental volumes of future produced bitumen and SCO and has an impact on the project announcements and construction. Although the federal government had approved the expansion of the Trans Mountain pipeline and Line 3 refurbishment and expansion,¹ both projects are facing opposition and hence incremental growth in oil sands production post-2018 will face market access challenges, unless there is a significant increase in rail transport, additional export pipeline capacity or a reduction in the amount of diluent used to transport non-upgraded bitumen.

**Oil Sands Production – Three Scenarios**

The projection of crude bitumen and SCO production is dependent on information provided by oil sands producers. This includes data on production capacity provided to the Alberta regulator, in addition to other publicly available documents, such as annual reports, investor presentations and press releases. The projections include production from existing projects as well as new projects that are under construction, approved, awaiting approval, and announced.² This year the projection period is 2018 to 2038, inclusive.

Figure 3.1 illustrates the possible paths for production under the three scenarios. For an oil sands producer, a project’s viability relies on many factors, such as but not limited to the demand-supply relationship between production, operating and transportation costs (supply side) and the market price for blended bitumen and SCO (demand). Oil prices, high construction costs, the probability of construction and regulatory delays, availability of suitable and accessible refinery capacity, and environmental performance metrics and other risk factors have and might cause significant delays for projects.

Availability of the right skilled labour could also be a risk factor. According to the 2017 labour update by PetroLMI,³ the addition of operations roles will be somewhat offset by the loss of capital-related jobs as major projects that were under construction prior to the 2014 downturn move into operation in 2017 and 2018. In situ operations will add workers as additional production comes on stream. Meanwhile, there will be a decrease in the number of upgrading

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¹ John Pail Tasker. “Trudeau cabinet approves Trans Mountain, Line 3 pipelines, rejects Northern Gateway”.  
² Announced projects are assigned with high uncertainties regarding timing and project production capacities.
jobs as investment in this sub-sector slows considerably following completion of projects currently under construction.

*Total production from oil sands areas totalled 2.77 MMBPD in 2017, comprised of in situ (thermal and cold bitumen) production of 1.51 MMBPD and mining production of 1.27 MMBPD within the boundaries of the oil sands areas.*\(^4\) Total production in 2016 was 2.54 MMBPD, meaning the oil sands production grew 9.2 percent year-over-year. Production from oil sands includes an increasing share of Alberta’s and Canada’s crude oil production. In 2017, non-upgraded bitumen and SCO production made up 61 percent of total Canadian crude production and 82 percent of Alberta’s total production.

In the **High Case Scenario**, production from mining and in situ projects (thermal and cold bitumen) is set to grow to 3.4 MMBPD by the end of the decade and 5 MMBPD in 2030, peaking at an all-time high of 7.5 MMBPD by 2038. In the **Low Case Scenario** production rises to 3.1 MMBPD in 2020, 3.4 MMBPD by 2030 and flattens to 4.0 MMBPD by the end of the forecast period. CERI’s **Reference Case Scenario** provides a base case of the oil sands production. Projected production volume will increase to 3.2 MMBPD by 2020 and 4.1 MMBPD in 2030, peaking at 5.5 MMBPD by 2038 (see Figure 3.1 and Table 3.1).

**Table 3.1: Oil Sands Production Forecast (MBPD)**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2038</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Case</td>
<td>3,388</td>
<td>3,977</td>
<td>4,970</td>
<td>6,735</td>
<td>7,485</td>
</tr>
<tr>
<td>Reference Case</td>
<td>3,239</td>
<td>3,528</td>
<td>4,090</td>
<td>5,143</td>
<td>5,465</td>
</tr>
<tr>
<td>Low Case</td>
<td>3,097</td>
<td>3,129</td>
<td>3,367</td>
<td>3,928</td>
<td>3,990</td>
</tr>
</tbody>
</table>

Source: CERI

---

\(^4\) Totals may not add up due to rounding. Historical production from the Alberta provincial regulator.
Achieving any of the levels of production outlined in the three scenarios requires a substantial number of inputs, of which capital (both strategic and sustaining) and natural gas are critical. Without the required capital, an oil sands project cannot be constructed. The project, with current technologies, cannot operate without an abundant and affordable supply of natural gas. Lastly, once the facility is operating there is an ongoing need for sustaining capital to ensure that production volumes stay at their design capacities. These and other requirements are discussed in the next section.

**Reference Case Scenario**

This section will focus on the results of CERI’s Reference Case Scenario. Projections of bitumen production, capital and operating costs, economic impacts, diluent, natural gas and emissions are included in the discussion.

**Oil Sands Production – Historic and Forecast**

A comparison is presented between CERI’s Reference Case production and other agencies’ forecasts, such as CAPP, the AER, and the NEB that report oil sands forecasts. Figure 3.2 illustrates the comparison of bitumen production between CERI and the three agencies. CERI’s total production projection from oil sands areas spans from 2018 to 2038, inclusive. All four

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5 CAPP, “Canadian Crude Oil Forecast and Market Outlook”, June 2017
outlooks are relevantly similar up to 2030. CAPP and AER projections stop at around that time; only the NEB’s forecast is long term. CERI’s **Reference Case** production in the latter part of the forecast period is projected to grow faster than the NEB’s. This is supported by an assumption of a continual increase in oil prices which would attract more greenfield development.

Bitumen production in CERI’s **Reference Case** grows by an average annual of approximately 130,000 BPD or just over 3 percent per year. The production level is expected to reach 3 MMBPD by the end of 2018 and continue to grow moderately. The growth rate will be slower in the first half of the forecast period than in the last; in particular, the annual growth rate between 2018 and 2028 is 2 percent. In contrast, the annual growth rate between 2028 and 2038 is almost double, at 3.76 percent. The slight decline in 2016 is the result of wildfires in northern Alberta that happened mid-2016 affecting oil sands projects. The 2028 estimated drop of 125,000 BPD is due to project’s end date assumption of projects, in this case, it is one of the older oil sands mines coming offline.

**Figure 3.2: Bitumen Production Forecast – Comparison**

Source: CERI, AER, CAPP, NEB.
Illustrated in Figure 3.3 are the production projections by extraction type. Total mined bitumen production is expected to increase from 1.3 MMBPD in 2017 to its peak of almost 1.6 MMBPD by 2027, and remain flat for the rest of the period. The decrease in mining production in 2028 is due to one of the phases of a legacy mine coming offline before another phase starts operations. The remainder of the projection period remains flat.

Since 2012, in situ production continues to be higher than mining. Production is expected to increase continuously from 1.5 MMBPD in 2017 to a peak of 3.7 MMBPD in 2038, growing at 4.7 percent annually, as a result of the addition of new proposed projects, the expansion of existing and construction of approved projects. The share of bitumen production from mining will continue to decrease – from 45 percent in 2017 to 28 percent in 2038. By the end of the projection period in 2038, in situ bitumen accounts for the majority of incremental bitumen barrels.

**Figure 3.3: Bitumen Production by Extraction Type – Reference Case**

![Bitumen Production Chart]

Source: CERI, CanOils

**Natural Gas Demand**

The oil sands industry increasingly accounts for a larger portion of the provincial gas market in Alberta. Overall, natural gas demand growth in the province of Alberta over the coming decade is expected to come primarily from the industrial sector including oil sands, power generation and petrochemical sectors. The oil sands industry increasingly accounts for a larger portion of the provincial gas market in Alberta.
Figure 3.4 displays the range for thermal energy/gas intensity factors developed by CERI for the different project types including extraction processes such as mining, in-situ (SAGD, CSS, Primary/EOR, and electric-heating technologies), upgrading projects such as coking and hydrocracking, as well as integrated extraction (mining or SAGD) and upgrading projects. Figure 3.5 displays (natural gas equivalent) hydrogen intensity factors for upgrading projects.

The ranges were calculated based on statistical methods which are meant to capture most of the collected data values (excluding large outliers), with a median value illustrated by the black square-shaped marker, while the blue diamond-shaped marker displays the latest empirical value collected for a given project type (where applicable), which is generally an average for 2014 (or 2013, depending on data availability).

**Figure 3.4: Oil Sands Industry Thermal Energy Intensity Factors by Project Type (GJ/bbl of Output)**

Source: CERI

Thermal energy intensity factors are higher for in situ thermal projects on average than for mining projects as a result of a higher gas requirement for steam generation. Natural gas use is the largest contributor to total energy requirements for thermal in situ projects. On the other hand, upgrading facilities require natural gas for hydrogen production. Hydrogen is used in the primary upgrading stage at hydro-cracking upgraders and in all upgrading projects with secondary

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8 For more information on how these factors were developed, see CERI Study 151, “Oil Sands Industry Energy Requirements and Greenhouse Gas (GHG) Emissions Outlook (2015-2050).” August 2015.
upgrading processes for the purpose of hydro-treating. This allows for the production of clean sweet SCO (or fractions thereof such as naphtha and diesel fuel).

Figure 3.5: Oil Sands Industry Hydrogen Energy Intensity Factors by Project Type (GJ/bbl of Output)

Source: CERI

Hydrogen is mainly produced at upgrading operations from natural gas purchases via steam methane reforming (SMR). SMR is a two-step process that produces hydrogen from methane. Some upgraders will use internally produced fuel gas to produce hydrogen. In some areas where industrial integration exists, upgrading operations have the option of purchasing pure hydrogen streams from nearby industrial facilities.\(^9\)

Thermal energy and hydrogen intensity factors are converted to a volumetric basis in order to come up with an estimate for gas demand for the oil sands industry by project type. Figure 3.6 displays the results of such analysis.

Figure 3.6 also illustrates the total oil sands demand for gas (including natural gas, fuel gas, syngas, and associated gas) for the purpose of meeting thermal energy requirements and feedstock for hydrogen production. The oil sands industry’s natural gas purchases refer to marketable natural gas purchased from the market, for meeting thermal energy and hydrogen requirements, after accounting for internally produced and utilized gas sources.

\(^9\) As an example, upgrading projects can purchase hydrogen streams from nearby refineries and petrochemical facilities.
Total gas demand for the oil sands industry is expected to increase from almost 3.4 billion cubic feet per day (BCFPD) in 2017 to almost 6.6 BCFPD by 2038. Total gas purchases made up 70 percent of total gas demand in 2017.

The majority of the growth in gas demand from the industry is expected to come in the form of thermal energy demand requirements for SAGD projects, followed by mining and upgrading projects. Under the assumption of constant energy intensity factors in the Reference Case, this trend is primarily the result of an evolving product mix on a project-type basis rather than technological changes.

**Figure 3.6: Natural Gas Demand and Purchases for Thermal Energy and Hydrogen Production**

![Graph showing natural gas demand and purchases from 2007 to 2038.](image)

Source: AER, CERI

**Diluent Demand**

Diluent is an important component of oil sands operations for transportation purposes. Adding diluent brings bitumen to pipeline specifications and allows it to flow. Currently, domestic sources and imports of condensate satisfy the diluent demand for bitumen production.

In oil sands operations, demand for diluent is driven by non-integrated projects whose primary output is a crude bitumen blend such as WCS. The diluent pool, in turn, is made up of various
components including light crudes such as SCO and condensates (ultra-light crude), but also natural gas liquids (NGLs) such as butane, but most importantly, pentanes plus. More recently, butane and propane are being used to pilot solvent-aided in situ projects, where a combination of steam and solvent aids in the extraction of bitumen, thus reducing the need for natural gas to create steam and reducing overall GHG emissions from the production process.

While the choice of diluent used by different project operators is based on economic and technical considerations,\(^\text{10}\) pentanes plus remains the diluent of choice for oil sands operators. Figure 3.7 displays the estimated demand for diluent by project type and by diluent type.

**Figure 3.7: Diluent Demand by Type of Diluent**

![Diluent Demand by Type of Diluent](image)

Source: AER, CERI

Total demand for diluent for 2017 was almost 0.7 MMBPD including pentanes plus and condensate, SCO, and butane. The diluent demand is expected to rise in tandem with bitumen production, as more in situ projects come online, requiring diluent for transportation, assuming

\(^{10}\) See CERI Study 133, “Canadian Oil Sands Supply Costs and Development Projects (2012-2046).” May 2013.
no technological breakthroughs.\textsuperscript{11} Total demand will rise from the current level to over 1.6 MMBPD by 2038.

The demand for diluent is met through domestic supply and imports from the US. Production of pentanes plus, a predominant fuel used as a diluent, is estimated by the AER to remain flat for the foreseeable future at just under 270,000 BPD. A combination of factors including the continued focus of gas producers on liquids-rich and “oily” gas plays like the Duvernay, and the potential commissioning of liquefied natural gas projects (LNG) in British Columbia could change the production forecast in the upward direction.

Meanwhile, it is important to consider that diluent import requirements are a function of local production volumes and overall demand levels. CERI’s diluent demand projection is based on the premise crude bitumen would be blended, that is, no field upgrading will occur, in which case diluent demand for blending purposes could decrease. Partial upgrading, among other technologies, could impact how bitumen is processed and transported (i.e., without minimal or no addition of diluent).

Alternatively, crude bitumen could be moved by rail, and this will increasingly be the case under continued market access and pipeline logistics constraints, this is not to say that crude-by-rail is not experiencing its own issues like non-availability of rail cars, required train personnel, capacity and back-logs on transporting other commodities. Regardless, rail can move bitumen with little to no diluent required.\textsuperscript{12}

Last, but not least, in the context of diluent import requirements it is important to consider the infrastructure required to move such volumes to the Alberta diluent market. Diluent import infrastructure includes pipelines such as the Southern Lights pipeline and the Cochin pipeline which was reversed and switched over from propane to diluent service. Other infrastructure includes rail terminals dedicated to diluent service in the Edmonton/Fort Saskatchewan area, as well as a terminal on the Kitimat coast that moves diluent via rail to Alberta.

Overall, diluent demand levels will be driven by the production of crude bitumen blends rather than synthetic crude from oil sands operations. Given that demand is well above and beyond local production levels, diluent will continue to be imported in large volumes. Rail transportation of bitumen has the potential to reduce diluent demand depending on the type of blend/product transported but also to add to the diluent pool supply by making use of diluent haul-backs. Technologies, such as partial upgrading, could also create products that meet pipeline specifications without additional diluent.

\textsuperscript{12} Dilbit via rail would use the same amount of diluent as dilbit in pipelines or around 30%. Railbit will require about 17% diluent and cleanbit would require no diluent at all. Railbit and cleanbit would require coil and insulated (C&I) rail cars for transportation purposes.
**Transportation Capacity**

The assessment of future production is not limited by transportation capacity. One assumption is that pipelines and rail will provide the needed service to move additional volumes of bitumen. Figure 3.8 indicates the amount of existing pipeline transportation capacity and the contribution of new pipeline projects including Enbridge Line 3, the TMX expansion and the new KXL pipeline.

![Figure 3.8: Crude Pipeline Transportation Capacity from Western Canada](image)

The current existing export pipeline capacity out of western Canada is 4 MMBPD. In the long run, under the Reference Case, bitumen production is expected to grow, and the need for expansion in existing oil pipeline capacity comes at the forefront of challenges that the oil sands industry is facing today. As western Canadian crude oil production continues to grow, the leverage of these resources for economic benefits to the nation will depend on the ability to connect this growing supply with downstream demand.

It is also important to stress how some excess capacity is crucial to be able to manage pipeline maintenance times and to provide flexibility for new market development. Not to mention that constraints in pipeline capacity and the lack of access to existing and new demand centres have deepened the discount between WTI and western Canadian crudes and hence have had a severe impact on the netbacks realized by Canadian producers.

With the federal government approving the expansion of Kinder Morgan’s Trans Mountain pipeline and Enbridge’s Line 3 replacement, export pipeline capacity would increase by almost 1 MMBPD (Expansion of TMX – 590,000 BPD and Line 3 replacement – 370,000 BPD), alleviating some existing constraints in the mid-term. However, both projects face significant opposition and...
further delays. In January 2018, Kinder Morgan said that the Trans Mountain expansion with a ballooned cost of $7.4 billion\textsuperscript{13} could be facing a one-year delay, with a new onstream date of December 2020.\textsuperscript{14} Enbridge’s Line 3 replacement project is facing similar uncertainty. The company says the $8.2 billion project’s start time is planned for the end of 2019. If TransCanada’s Keystone XL is revived, it will add another 830,000 BPD, but the project has been in development for nearly a decade. With recently secured 20-year commitments from shippers in the amount of 500,000 BPD,\textsuperscript{15} TransCanada might move forward. It has not officially green-lighted the project and is still working toward a final investment decision (FID). CERI has estimated its potential onstream year to be 2021.

In the meantime, producers may use rail to move their products. The terminal outbound capacity in Alberta and Saskatchewan is approximately 750,000 BPD but only 20% is utilized. Rail capacity is indeterminate and ever changing, influenced by the use of assets and resources (capacity of railcar fleet, rail crews and the power of locomotives), the management of flow and operations and the overall basic rail track infrastructure (track structure, sidings double track).\textsuperscript{16}

**Emissions**

Greenhouse gas (GHG) emissions are a major area of environmental concern in the oil sands sector. Increasing concentrations of anthropogenic (i.e., human-produced) GHGs in the atmosphere are a major driver of climate change attributed to human activity. GHGs influence climate by trapping radiation from the earth’s surface, resulting in an overall warming effect on the planet. This can lead to a number of potentially adverse outcomes such as changing climate patterns (for example, increased or decreased precipitation) and rising sea levels.

Total Canadian emissions of CO\textsubscript{2}eq were 732 Mt or 1.6 percent of global emissions,\textsuperscript{17} and of these emissions, 9.3 percent came from the oil sands sector.\textsuperscript{18} The effects of the sector on Canada’s total emissions and ability to meet international commitments to GHG abatement are substantial. Canada has committed under the Paris Agreement of 2015 to decrease emissions by 30 percent below 2005 levels by the year 2030. Canada’s 2050 reduction targets are set at 80 percent below 2005.

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\textsuperscript{13} https://www.kindermorgan.com/pages/business/canada/tmep.aspx
\textsuperscript{16} Quorum Corporation website, Railway Capacity Background & Overview, Rev: 10/12/05, pp. 1-2.
\textsuperscript{17} Environment and Climate Change Canada. “National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada”.
\textsuperscript{18} Environment and Climate Change Canada.
Besides the international commitment, Alberta’s Climate Change Leadership Plan includes an emissions cap on the oil sands industry in the order of 100 Mt of CO$_2$eq. Not exceeding the absolute cap is of importance to government and industry.

There are two methods to consider when looking at emissions performance. The first is GHG emissions intensity, which is the emissions in CO$_2$ equivalents per barrel of bitumen or synthetic crude oil produced. Emissions intensity is valuable for examining whether changes in operating conditions at a project level have been effective in light of changing production volumes. The second is the bulk emissions for a project. A project can make significant efforts to reduce GHG emissions, but total emissions can still rise if bitumen production has risen at a faster rate than emissions have fallen. Looking at bulk emissions can obscure progress made to curb GHGs, but this metric is important to examine as the climate response of emissions will not depend on how many resources were extracted during the emission of these gases.

Figure 3.9 illustrates the total emissions projection for the Reference Case production forecast. The on-site emissions projection includes emissions from existing upgrading, electricity or fugitive emissions and flaring. Current on-site emissions projected to grow from 72 MT/year in 2017 to 103 MT/yr in 2030, breaching the emissions cap of 100 MT. Increasing production in this sector makes the meeting of international commitments increasingly difficult to meet, and thus there is interest in reducing the amount of GHGs emitted to extract bitumen from the oil sands and generate synthetic crude oil. In CERI Study 164, the Institute outlined several techno-economic paths on how to grow oil sands production but reduce overall emissions.
After two years of deep capital cuts, total capital investment in Alberta’s oil and gas sector increased in 2017 to C$33.6 billion (an almost 30 percent increase from 2016), despite a continued decrease in the oil sands sector. Oil sands capital spending is expected to stay weak in 2018 and remain flat until the end of the decade. A few producers may actually boost their budgets, but the majority keep deferring new projects in the short term, focusing instead on sustaining existing facilities and lowering costs of production.

Total capital spending requirements are broken down by project type and are illustrated in Figure 3.10. Over the 21-year projection period from 2018 to 2038 inclusive, the total initial and sustaining capital required for all projects is projected to be C$406.5 billion under the Reference Case Scenario, almost $100 billion lower than last year’s projection. Capital investment for in situ projects surpasses the capital spent for mining projects, which is consistent with the ongoing trend to invest more into in situ projects rather than mining. From 2018 to 2038, it is projected that almost C$122 billion (initial and sustaining) will be invested into mining projects and C$262
billion will be invested into in situ thermal and solvent as well as primary and EOR cold bitumen projects. Upgrading projects see the least amount of capital spent, amounting to C$22 billion.

**Figure 3.10: Total Capital Invested by Project Type**

Historical and forecast capital expenditures from 2007 to 2038 are shown in Figure 3.11. As evidenced in the industry, capital expenditures on oil sands projects have been on the decline since 2014, coinciding with a decrease in oil prices. Investment fell by 30 percent to C$15.4 billion in 2016 and a further estimated 17 percent in 2017. In addition, capital expenditures in 2018 are forecast to decrease to around C$12 billion. The 2014 peak spending of almost $34 billion in not projected.

Going forward, overall capital expenditures average $19 billion per year in the 2018-2038 forecast period, growing at approximately 2 percent. There are lingering risk factors that could impact the capital outlay outlook – further deferral of higher-cost projects; successful deployment of cost-reduction strategies; uncertainty on how the industry will meet a 100 megatonne cap on oil sands emissions; and uncertainty over export pipeline development projects. Expenditures in the oil sands are expected to be invested in new thermal projects or primarily aimed at sustaining capital and expanding existing projects.
The methodology related to estimating capital investment is related to project capacity additions in the form of expansions of existing projects and greenfield development.

**Figure 3.1: Total Oil Sands Capital Expenditures by Project Type**

![Graph showing Total Oil Sands Capital Expenditures by Project Type from 2007 to 2017.](image)

Source: CERI, CAPP, CanOils

Historical and forecast operating costs by project type are presented in Figure 3.12. As can be seen, total operating costs have been declining since 2014 with a year-on-year decrease of 10 percent in 2015 and 8 percent in 2016. This is the result of not only declining oil prices, but oil sands project operators have managed to reduce their overall operating cost per barrel of bitumen or SCO produced. Over the forecast period, total operating costs are expected to increase in line with increased production levels, averaging $22.7 billion per year.
Oil Sands Economic Contribution

The oil sands industry is a significant contributor to the provincial and Canadian economies in the form of royalty and land payments and taxes. It also employs thousands of people. The sector has experienced sustained cost-cutting, restructuring and deeper than anticipated job losses since the oil price collapse in 2014. This resulted in an 8 percent reduction in labour in 2015 and 2016, which translates to approximately 28,924 workers directly employed in Canada’s oil sands sector at the end of 2016 according to PetroLMI.\(^\text{19}\)

According to their latest labour outlook,\(^\text{20}\) total employment growth in the oil sands sector is expected to be 4,000 jobs by 2021 as companies shift their spending from expansion to maintenance, and repair and optimization of their operations. The total direct employment in the oil sands is forecast to be 32,883 jobs in 2021 (see Figure 3.13).

In 2017, the workforce requirements will reflect the transition of capital projects into operation. In oil sands mining the growth is expected to occur in production-related jobs. The addition of operations roles will be somewhat offset by the loss of capital-related jobs as major projects that were under construction prior to the downturn move into operation in 2017 and 2018. In situ projects will add workers as additional production comes on stream. Meanwhile, there will be a decrease in the number of upgrading jobs as investment in this sub-sector slows considerably following completion of projects currently under construction.

**Figure 3.13: Oil Sands Sector Labour Demand Forecast (# of jobs)**

![Graph showing oil sands sector labour demand forecast](image)

Source: PetroLMI, CERI

The continued focus on decreasing costs, increasing operational efficiencies and sustaining labour productivity gains will have an impact on oil sands workforce requirements between 2018 and 2021. Jobs added in the forecast period will be primarily in occupations that support production as well as the maintenance and optimization of existing operations. The sector is also expected to enhance operational productivity through technology, including additional automation.

A decrease in growth-related capital spending and a shift towards sustaining and maintenance projects that drive operational reliability and efficiency will determine the make-up of labour skills required. Table 3.2 describes the skills that will be desired in the next five years.
In August 2017, CERI published very detailed results of economic contributions that the industry brings to Canada and the US over the next ten years.\textsuperscript{21} The impact outlook was done using last year’s Reference Case bitumen production forecast. This year, the Reference Case production projections are lower by 12 percent in comparison to last year’s levels. Hence, the economic impact results were adjusted accordingly.

The overall contribution of the Canadian oil and gas industry to the Canadian GDP amounted to $108 billion in 2017 or nearly 6.5 percent share of total Canadian GDP, which is a half percent higher than the 2016 contribution.\textsuperscript{22} Oil sands represent a significant portion of the oil and gas sector, bringing in almost half, or $44.2 billion, of the $108 billion.

The industry is projected to contribute $1.4 trillion to the Canadian GDP over the next 10 years.\textsuperscript{23} Most of the impact will be felt in Alberta, but Saskatchewan is a growing contributor as more oil sands projects from that province are coming online. Despite a decrease in capital and operating expenditures (which drive the economic impacts modelling), governments will still benefit from tax revenues. Those are estimated to be $139 billion in federal tax revenues and $86.7 billion in provincial taxes over the forecast period.

\begin{table}[h]
\centering
\begin{tabular}{|l|c|c|}
\hline
Occupation (NOC 2011) & 2016 Estimated Employment & 2017-2021 Expansion Demand (% growth) \\
\hline
Total oil sands sector & 28,900 & 4,000 (+14%) \\
Heavy equipment operators (except crane) (7521) & 4,505 & 1,000 (+22%) \\
Power engineers and power systems operators (I9241) & 4,915 & 795 (+16%) \\
Heavy-duty equipment mechanics (7312) & 1,400 & 290 (+21%) \\
Facility operation and maintenance managers (0714) & 1,265 & 165 (+13%) \\
Managers in natural resources production, drilling and well servicing (0811) & 780 & 150 (+19%) \\
Industrial electricians (7242) & 765 & 145 (+19%) \\
Millwrights (7311) & 715 & 135 (+19%) \\
Engineering managers (0211) & 1100 & 120 (+11%) \\
Petroleum, gas, chemical process operators (no steam ticket required) (I9222) & 520 & 110 (-22%) \\
Instrumentation technicians (I7243) & 725 & 95 (+33%) \\
\hline
\end{tabular}

Source: PetroLMI

\end{table}

\textsuperscript{21} CERI Study 166, “Economic Impacts of Canadian Oil and Gas Supply in Canada and the US (2017-2027)”, August 2017.
\textsuperscript{22} Statistics Canada, CANSIM, Table 379-0031.
\textsuperscript{23} Base numbers are sourced from CERI Study 166, “Economic Impacts of Canadian Oil and Gas Supply in Canada and the US (2017-2027)”. August 2017. Then adjusted for lower production level.
Chapter 4: Conclusion

The steep global decline in oil prices has impacted the crude oil industry extensively and has slowed the pace of upstream investment around the world – including in heavy crude oil development in Canada. Since then, oil prices rebounded to the level conducive to increased production. CERI’s oil sands projections show that in the long run, bitumen production is expected to grow, albeit at a slower growth rate than previously forecasted. The growth in the bitumen production from the provinces of Alberta and Saskatchewan (which is also starting to develop its oil sands resources) would provide a net benefit to those provincial economies and nationally.

CERI forecast three scenarios based on different economic factors for bitumen production. In the High Case Scenario, production from mining and in situ projects (thermal and cold bitumen) is set to grow to 3.4 MMBPD by the end of the decade and 5 MMBPD in 2030, peaking at an all-time high of 7.5 MMBPD by 2038. In the Low Case Scenario, production rises to 3.1 MMBPD in 2020, 3.4 MMBPD by 2030 and flattens to 4.0 MMBPD by the end of the forecast period. CERI’s Reference Case Scenario provides a base case of the oil sands production. Projected production volume will increase to 3.2 MMBPD by 2020 and 4.1 MMBPD in 2030, peaking at 5.5 MMBPD by 2038.

Figure 4.1: Bitumen Production Projections

Source: CERI, CanOils
However, the growth is dependent on several factors. GHG emissions are a major environmental concern in the oil sands sector. Increasing concentrations of anthropogenic (i.e., human-produced) GHGs in the atmosphere are a major driver of climate change attributed to human activity. This can lead to a number of potentially adverse outcomes such as changing climate patterns (for example, increased or decreased precipitation) and rising sea levels.

Total Canadian emissions of CO2eq were 704 Mt in 2016, a net decrease of 28 Mt or 3.8 percent from 2005 emissions. In 2016, the Energy Sector (consisting of Stationary Combustion, Transport and Fugitive Sources) emitted 572 Mt of greenhouse gases or 81% of Canada’s total GHG emissions. The effects of the sector on Canada’s total emissions and ability to meet international commitments to GHG abatement are substantial. Canada has committed under the Paris Agreement of 2015 to decrease emissions by 30 percent below 2005 levels by the year 2030. Canada’s 2050 reduction targets are set at 80 percent below 2005.

Besides the international commitment, Alberta’s Climate Change Leadership Plan includes an emissions cap on the oil sands industry of 100 Mt of CO2eq. Not exceeding the absolute cap is of importance to government and industry. CERI shows in this report that under the Reference Case, without any improvements, emissions cap will be reached by 2029-2030. Under the scenario where the historic trend of decreasing intensities is assumed, the emissions cap is not reached for the forecast period. In order for emission intensities to continue to decline, process innovation using commercial and near-commercial technologies would have to be implemented throughout the bitumen extraction sector.

The lack of available export capacity is another challenge that the oil sands industry is facing. In last year’s report, CERI predicted that starting in 2018-2019, without additional pipeline capacity, the crude exports will be locked in and will have no market access. This is exactly what happened. As a result, the price differential started to widen again, the value of bitumen started to decline, producers started to store their crude or had to apportion it for pipeline transport, and rail use started to increase as well.

Expansion of pipeline infrastructure and shipping routes to international markets and the US would create opportunities for Canadian oil producers and benefit the Canadian economy as well. Allocating exports to other markets such as Asia and Europe also reduce dependence on the US market, which used to be Canada’s number 1 customer. Until it became our number 1 competitor.

The oil sands industry is a significant contributor to provincial and Canadian economies in the form of royalty and land payments, and taxes. In the latest Alberta Government Budget, bitumen royalties are estimated at $1.8 billion in 2018-19, $573 million lower than in 2017-18, due

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24 Environment and Climate Change Canada. “National Inventory Report Executive Summary 2018”.

25 In last year’s update, the emissions cap was reached sooner than in this year’s forecast. This is explained by the lower production level forecast.
primarily to the wider light-heavy oil price differential and higher exchange rate. The US$5 increase to WTI is more than offset by the differential discount. Royalties are forecast to increase to $2.9 billion by 2020-21. The main drivers are increasing oil prices, higher production and lower project costs.

The sector also employs thousands of people. The sector has experienced sustained cost-cutting, restructuring and deeper than anticipated job losses since the oil price collapse in 2014. This resulted in an 8 percent contraction in labour in 2015 and 2016, which translates to approximately 29,000 workers directly employed in Canada’s oil sands sector at the end of 2016 according to PetroLMI. According to their latest labour outlook, total employment growth in the oil sands sector is expected to be 4,000 jobs by 2021 as companies shift their spending from expansion to maintenance, repair and optimization of their operations. The total direct employment in oil sands is forecast to amount to 32,883 in 2021.

Overall, the challenge is to balance the benefits of oil sands production for Canada, with citizen concerns for the environment. Technology innovation provides a good solution to achieve both. In the long-term, new technologies and processes for bitumen production can reduce production costs, creating more value for industry and government, and at the same time reduce GHG emissions.

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