Crude Bitumen Supply

Mined and In Situ Bitumen Production

- Total combined mined and in situ bitumen production grew 11.9 per cent from 2016, reaching 451.1 thousand cubic metres per day ($10^3$ m$^3$/d) or 2838.7 thousand barrels per day ($10^3$ bbl/d).
- As shown in Figure S3.1, total mineable raw production increased by 11.2 per cent in 2017 due primarily to recovery from the Fort McMurray wildfires and project phases moving towards operation.
- Total mineable raw production is forecast to grow by 32.0 per cent by 2027 relative to 2017 levels; Suncor Energy’s (Suncor’s) Fort Hills project and Imperial Oil’s (Imperial’s) Kearl expansion project are forecast to contribute most of the added production in the near term, with future production limited by challenging economics.
- A number of in situ projects continued to ramp up production in 2017, increasing output by 12.4 per cent relative to 2016. Year-over-year growth in production for in situ projects was higher in 2017, mainly due to increased production of steam-assisted gravity drainage (SAGD) schemes; production increases for these and other in situ recovery
schemes more than offset lower production of primary and experimental schemes in 2017 relative to 2016.

- Total in situ production is forecast to grow 39.3 per cent by 2027 compared with 2017. This latest forecast is slightly higher than the previous one due to a reassessment of project start dates, an anticipated increase in the number of new applications, and expected technological advancements that will reduce operator costs and increase efficiencies.

- By 2027, in situ bitumen is forecast to account for 56.4 per cent of total raw bitumen produced, as shown in Table S3.1.

- Total raw bitumen accounted for 85.7 per cent of combined crude oil (excluding pentanes plus) and raw bitumen produced in 2017.

**Table S3.1 Crude bitumen production (10^3 m^3/d)**

<table>
<thead>
<tr>
<th></th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2027</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Raw production</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mineable</td>
<td>182.3</td>
<td>202.8</td>
<td>225.0</td>
<td>240.6</td>
<td>267.6</td>
</tr>
<tr>
<td>In situ</td>
<td>221.0</td>
<td>248.3</td>
<td>250.6</td>
<td>259.8</td>
<td>345.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>403.3</td>
<td>451.1</td>
<td>475.6</td>
<td>500.4</td>
<td>613.5</td>
</tr>
<tr>
<td><strong>Upgraded and nonupgraded production</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upgraded</td>
<td>147.7</td>
<td>163.8</td>
<td>171.8</td>
<td>177.5</td>
<td>191.9</td>
</tr>
<tr>
<td>Nonupgraded</td>
<td>233.0</td>
<td>257.5</td>
<td>268.1</td>
<td>286.5</td>
<td>383.9</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>380.7</td>
<td>421.3</td>
<td>439.9</td>
<td>464.0</td>
<td>585.8</td>
</tr>
</tbody>
</table>

^ Upgrading conversion losses result in marketable production totalling less than raw.

**Mining Project Highlights**

- Virtually all oil sands mines had year-over-year production gains in 2017, with the exception of Syncrude Canada's (Syncrude's) Aurora oil sands mine, which experienced an unplanned outage at its Mildred Lake upgrader in mid-March. Production increases at the mines were largely due to recovery from last year’s wildfires near Fort McMurray, new phases readying for operation, and efficiencies from integrating operations.

- Total mineable bitumen increased in 2017 by 11.2 per cent, reaching 202.8 \(10^3\) m^3/d (1562.5 \(10^3\) bbl/d). This increase was driven by year-over-year gains of 2.8 \(10^3\) m^3/d (17.6 \(10^3\) bbl/d) at the Athabasca Oil Sands Project (AOSP), including both the Muskeg River and Jackpine mines, now operated by Canadian Natural Resources Limited (CNRL); 1.7 \(10^3\) m^3/d (10.7 \(10^3\) bbl/d) at Imperial's Kearl mine; 10.6 \(10^3\) m^3/d (66.7 \(10^3\)
bbl/d) at Suncor’s operations; and $8.0 \times 10^3$ m$^3$/d ($50.3 \times 10^3$ bbl/d) at CNRL’s Horizon project.

- Suncor had the greatest year-over-year production increase in 2017 because its mining operations were closest to the 2016 Fort McMurray wildfires and therefore most adversely affected. As a result, Suncor’s mining production rose 28.0 per cent to $48.5 \times 10^3$ m$^3$/d ($305.2 \times 10^3$ bbl/d) compared with 2016 levels. Suncor’s mining production is forecast to grow substantially in 2018 with the addition of the Fort Hills project, anticipated to begin commercial operations in 2018. Limited production from Fort Hills, which averaged $0.3 \times 10^3$ m$^3$/d ($1.9 \times 10^3$ bbl/d) across 2017, has been included in the June 2018 update.

- Output at CNRL’s Horizon mine grew by an estimated 34.3 per cent to $31.3 \times 10^3$ m$^3$/d ($197.0 \times 10^3$ bbl/d) in 2017. Production from Phase 2B, completed in October 2016, steadily ramped up throughout 2017 and is projected to grow alongside that of the recently completed Phase 3 expansion. CNRL has also proposed a brownfield expansion, which could further increase nonupgraded production by up to $6.4 \times 10^3$ m$^3$/d ($40.0 \times 10^3$ bbl/d) and would use a paraffinic froth treatment to fill excess pipeline capacity with lighter, diluted bitumen.

- CNRL increased production at both its Muskeg River and Jackpine mines in 2017; both mines were formerly operated by Shell Canada Energy Ltd. (Shell) as part of the AOSP. Compared with 2016, production increased by 2.2 per cent to $23.1 \times 10^3$ m$^3$/d ($145.4 \times 10^3$ bbl/d) at the Muskeg River mine and by 12.7 per cent to $20.4 \times 10^3$ m$^3$/d ($128.4 \times 10^3$ bbl/d) at the Jackpine mine.

- Although Imperial’s Kearl mine continued to operate below production capacity in 2017 due to ore-preparation equipment problems, improved project reliability and project ramp up resulted in 5.8 per cent increase in production to $31.2 \times 10^3$ m$^3$/d ($196.3 \times 10^3$ bbl/d) compared with 2016. Imperial also announced plans to increase the design capacity of the mine from $35.0 \times 10^3$ m$^3$/d ($220.0 \times 10^3$ bbl/d) to $38.1 \times 10^3$ m$^3$/d ($240.0 \times 10^3$ bbl/d) between 2018 and 2019.

- Syncrude’s year-over-year production decreased by 5.9 per cent from 2016, averaging $48.0 \times 10^3$ m$^3$/d ($302.1 \times 10^3$ bbl/d) in 2017. Despite cost-cutting initiatives and recovery following the Fort McMurray wildfires, an explosion in mid-March at its Mildred Lake upgrader significantly reduced output at both of its mines and also affected upgraded and nonupgraded production at other operators’ projects.
In Situ Project Highlights

- ConocoPhillips Canada (ConocoPhillips) increased output at its Surmont project by 72.1 per cent to $19.1 \times 10^3$ m$^3$/d ($120.2 \times 10^3$ bbl/d) in 2017, despite reducing Surmont’s production by an estimated $9.5 \times 10^3$ m$^3$/d ($60.0 \times 10^3$ bbl/d) in April due to a shortage of synthetic oil from Syncrude to use as diluent. Following the disruption, ConocoPhillips was able to return to normal production by May and continue to increase its output.

- Cenovus Energy (Cenovus) continued to ramp up production at both its Christina Lake and Foster Creek projects in 2017. Both projects are now wholly owned by Cenovus, following the acquisition of ConocoPhillips’ nonoperated stake in May 2017.
  - Foster Creek Phases A through E underwent turnarounds in the first half of 2017 that reduced combined production by about $7.1 \times 10^3$ m$^3$/d ($44.7 \times 10^3$ bbl/d) in May compared with the rest of the year.
  - Increased output from Foster Creek Phase G was responsible for a 9.4 per cent increase in production to $24.4 \times 10^3$ m$^3$/d ($153.5 \times 10^3$ bbl/d) across the entire scheme.
  - Increased output from Christina Lake Phase F contributed to the 29.8 per cent growth in total production for the entire project, reaching $32.7 \times 10^3$ m$^3$/d ($205.8 \times 10^3$ bbl/d).
  - Construction of Christina Lake Phase G resumed after being suspended in 2015 due to low oil prices, allowing Cenovus to increase production towards a 2019 on stream date.

- Average production at MEG Energy’s Christina Lake project was down year over year by less than one per cent to $12.2 \times 10^3$ m$^3$/d ($46.8 \times 10^3$ bbl/d) in 2017 because the project experienced a second-quarter turnaround during the tie-in of new wells that are part of its enhanced modified steam and gas push (eMSAGP) Phase 2B. The eMSAGP initiative involves injecting noncondensable gas into the oil reservoir and drilling infill wells to reduce steam use and increase production. The company plans to ramp up Phase 2B to its full capacity of $15.9 \times 10^3$ m$^3$/d ($100.0 \times 10^3$ bbl/d) by 2019 and potentially begin its $2.1 \times 10^3$ m$^3$/d ($13.0 \times 10^3$ bbl/d) Phase 2B brownfield expansion in 2018, subject to market conditions.

- Devon Energy increased production by 6.3 per cent to $18.5 \times 10^3$ m$^3$/d ($116.4 \times 10^3$ bbl/d) in 2017 across its Jackfish project, which was largely driven by the ramping up of Phases 2 and 3. A three-week maintenance turnaround at Phase 2 during the summer temporarily reduced production by about $2.4 \times 10^3$ m$^3$/d ($15.0 \times 10^3$ bbl/d), but the improvements should enable the complex to produce higher volumes in 2018.
- Production at CNRL’s Primrose and Wolf Lake projects was higher in 2017 relative to 2016 by 11.6 per cent, totalling $12.5 \times 10^3$ m$^3$/d ($78.7 \times 10^3$ bbl/d). Production was lower in 2016 because the company was required by the AER to limit steam volumes at its Primrose East site in March 2016 after a bitumen seepage incident in 2013 was found to be caused by excess steam pressure used in its cyclical steam stimulation (CSS) operation.

- Nexen, a subsidiary of China National Offshore Oil Corporation Canada Incorporated, experienced a sharp decline in production at its Long Lake in situ project in 2016. The decrease was attributed to a slowdown in activity following an explosion in January 2016 that shut down the company’s integrated upgrader and to the project being shut-in as a precaution given its proximity to the Fort McMurray wildfires. In 2017, production rebounded to $6.5 \times 10^3$ m$^3$/d ($40.9 \times 10^3$ bbl/d), which is similar to output prior to years prior to 2016. Without its own integrated upgrader operational, Nexen was impacted by the shortage of synthetic oil resulting from the outage of Syncrude’s Mildred Lake upgrader; the AER estimates that this shortage reduced production by the project by an average of $1.2 \times 10^3$ m$^3$/d ($7.5 \times 10^3$ bbl/d) during April 2017.

- Suncor’s total in situ production was up 2.4 per cent year over year, averaging $33.9 \times 10^3$ m$^3$/d ($213.3 \times 10^3$ bbl/d) in 2017.
  - Production at Suncor’s Firebag scheme was adversely affected by the Fort McMurray wildfires but rebounded at the end of 2016. Suncor conducted its first five-year turnaround at Phases 3 and 4 in the second quarter of 2017. The project was slow to restart and ramp back up, resulting in production averaging $29.0 \times 10^3$ m$^3$/d ($182.5 \times 10^3$ bbl/d)—one per cent higher than 2016.
  - Production at Suncor’s MacKay River project increased by 11.4 per cent to $4.9 \times 10^3$ m$^3$/d ($30.8 \times 10^3$ bbl/d). Suncor has been testing technologies and supply integration with Syncrude’s upgrader to increase production and operating efficiency.
  - Suncor received regulatory approval for its Meadow Creek East joint venture with Nexen in 2017. The project will have two phases and will produce up to $12.7 \times 10^3$ m$^3$/d ($80.0 \times 10^3$ bbl/d), with production starting as early as 2023. Subject to approval, Suncor also plans to add another single $6.4 \times 10^3$ m$^3$/d ($40.0 \times 10^3$ bbl/d) phase to its Meadow Creek West project that would begin operating by 2025.
  - Noteworthy for its sheer scale, Suncor’s proposed Lewis project could potentially produce up to $25.4 \times 10^3$ m$^3$/d ($160.0 \times 10^3$ bbl/d); although Suncor has not yet approved the wholly owned project, nor received regulatory approval, construction is proposed to begin in 2024 and operation by 2027.
Stable, albeit challenging, prices, supported the moderate increase in bitumen production in 2017 relative to 2016. With no assets lost to the Fort McMurray wildfires, the projects affected last spring and summer have since recovered. Other factors contributing to growth included an increase in the number of active bitumen wells, particularly primary wells in the Peace River and Cold Lake oil sands areas (OSAs).

The forecast of increased production over the next decade is based on projects coming on stream that began before the price drop and other projects that received regulatory approval and favourable financial investment decisions during the downturn. Production will continue to grow during the forecast period as projects with capital that has already been committed or spent are developed and brought on production.

The forecast accounts for market uncertainty and a lag period for capital to be deployed, resulting in projects being delayed further out in the forecast horizon and a lower outlook compared to last year’s. Volumes are forecast to continue to grow gradually as several existing projects cautiously continue to ramp up production. The lower capital currently accessible for new schemes, particularly where multiple new and existing projects are competing for a company’s funding, are considered in project timelines. Companies are currently focusing on cost savings and efficiency rather than aggressively pursuing expansions and growth. Consequently, a number of new projects and expansions in early phases of development have been deferred and were excluded from the forecast.

Provincial and federal climate change policies have the potential to impact investment decisions and subsequent production. Alberta’s Oil Sands Emissions Limit Act proposes an emissions limit on the oil sands sector of 100 megatonnes (Mt) per year. Preliminary analysis by the AER indicates that oil sands production is within the 100 Mt emissions limit during the forecast period based on current emissions rates. The Government of Alberta continues to consult with the Oil Sands Advisory Group on implementation of this limit. Alberta’s Climate Leadership Plan and federal plans for a pan-Canadian minimum price on carbon have been accounted for in this year’s crude bitumen supply cost estimates and are further discussed in that section’s methodology.

Based on the crude bitumen supply cost estimates for 2017, current prices are insufficient to encourage widespread development of greenfield projects in the near term. However, expansions of existing mines and in situ schemes stand to benefit from reduced costs associated with using existing infrastructure, labour, and materials. Producers are exploring and capitalizing on various cost-saving opportunities, including modularizing and standardizing facilities, allowing for reduced well pad sizes and increased well lengths. Operators are also exploring next-generation facility designs that reduce project footprints, equipment, and construction periods.

Lower operating costs for in situ and mining operations have been realized in terms of natural gas and electricity prices contributing to decreased fuel costs. The use of solvents and other
methods to improve bitumen recovery rates and reduce emissions from in situ projects continue to be tested and developed. However, although new technology, such as solvents, may appeal to larger operators to lower costs, smaller operators are likely to be more hesitant to risk capital on experiments. This suggests that while technology may lower long-run costs, some operators may not be able to deploy it immediately and will experience higher supply costs as a result.

For OSAs, as shown in Figure S3.2 and Table S3.2, all areas saw a net positive in situ production growth in 2017. The Athabasca region rose 16.7 per cent increase mainly as a result of an increase in the number of wells and SAGD projects continuing to ramp up production. Production in the Peace River OSA increased 20.0 per cent compared with 2016 and production in the Cold Lake OSA grew by less than one per cent. Growth in the Peace River and Cold Lake
OSAs were primarily due to the improved productivity from primary and CSS schemes prevalent in both those areas.

**Upgraded Bitumen Production**

![Graph showing upgraded bitumen production](image)

*Figure S3.3 Alberta upgraded bitumen (SCO*) production*

![Table S3.3 Average daily upgraded bitumen production in 2017a](image)

<table>
<thead>
<tr>
<th>Company/project name</th>
<th>Production (10^3 m^3/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CNRL Horizon</td>
<td>27.4</td>
</tr>
<tr>
<td>North West Redwater Partnership Sturgeon Refinery^a</td>
<td>0.3</td>
</tr>
<tr>
<td>Shell Scotford</td>
<td>44.0</td>
</tr>
<tr>
<td>Suncor</td>
<td>51.9</td>
</tr>
<tr>
<td>Syncrude</td>
<td>40.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>163.8</strong></td>
</tr>
</tbody>
</table>

Note: Any discrepancies are due to rounding.

^a Sturgeon refinery produces only diesel and limited diluent, which is reported as synthetic production.

- Average daily upgraded bitumen production in 2017, as shown in Table S3.3, was up 10.9 per cent from 2016, despite a significant outage at Syncrude’s upgrader. Increased production was primarily due to operations recovering following the Fort McMurray wildfires and Phase 3 becoming operational at CNRL’s Horizon upgrader. Nexen’s Long Lake upgrader continues to remain off line and has been removed from this year’s forecast. While the North West Redwater Partnership Sturgeon refinery (Sturgeon
refinery) is intends to produce diesel and limited amounts of diluent, current reporting shows these refined petroleum products to be classified as synthetic crude volumes. For consistency in reporting, Sturgeon refinery volumes will be included in the upgraded bitumen forecast. Figure S3.3 shows that upgraded bitumen production is anticipated to increase by 17.2 per cent between 2017 and 2027.

- Over the forecast period, the percentage of crude bitumen sent for upgrading is forecast to decline from 42.9 per cent of total raw bitumen produced in 2017 to 35.6 per cent in 2027. On average, about 15 per cent of raw bitumen used as feedstock for upgrading is lost in the conversion process; in 2017, this conversion loss grew to about 16 per cent due to higher throughput, mainly due to the rebound of Suncor and its use of coking processes. The growth in production of nonupgraded bitumen is expected to outpace that of upgraded bitumen mainly because new mines, namely Fort Hills and Kearl, will not have upgrading capabilities.

Upgraded Project Highlights

- An explosion in mid-March at Syncrude’s Mildred Lake facility took the facility off line for several months and resulted in a widespread supply shortage of synthetic crude oil (SCO), which is used as a diluent to move heavier, nonupgraded bitumen through pipelines. This resulted in a number of other producers scaling back their operations, particularly during April, as they scrambled to find alternatives. After production was steadily restored by August, Syncrude’s upgraded output was $40.2 \times 10^3 \text{ m}^3/\text{d}$ ($253.0 \times 10^3 \text{ bbl/d}$) in 2017.

- Production at CNRL’s Horizon project grew to $27.4 \times 10^3 \text{ m}^3/\text{d}$ ($172.4 \times 10^3 \text{ bbl/d}$) in 2017 alongside that of the recently completed Phase 3 expansion and is projected to continue ramping up through 2018. Production slightly decreased in the fall due to a planned 45-day turnaround and to preparations for tying in the Phase 3 expansion.

- Despite CNRL acquiring a 70 per cent interest in the Scotford upgrader in March 2017, Shell remains the operator of the facility. Compared with 2016, Scotford increased synthetic output to $44.0 \times 10^3 \text{ m}^3/\text{d}$ ($276.9 \times 10^3 \text{ bbl/d}$). A valve leak reported in November 2017 temporarily took the upgrader off line.

- Suncor upgraded production recovered to $51.9 \times 10^3 \text{ m}^3/\text{d}$ ($326.6 \times 10^3 \text{ bbl/d}$) during 2017, even with planned maintenance at its Upgrader 1 unit that reduced output for several weeks.

- An explosion at the hydrocracker unit at Nexen’s Long Lake facility occurred in January 2016, and SCO production was halted thereafter. Nexen shut down its upgrading operations indefinitely in July 2016 and has not indicated a restart date.
Mergers and Acquisitions

Several large mergers and acquisitions occurred during 2017 as companies adjusted their corporate strategies, prioritized assets, and focused on specializations. By consolidating their upstream assets, in combination with increasing recovery efficiencies, decreasing operating costs, and implementing advances in technology, operators can increase their production capabilities. Some of the transactions in 2017 resulted in international companies exiting Alberta’s oil sands, raising some concerns about loss of foreign investment, but domestic companies assumed control to ensure that development continues.

Three of the largest oil sands deals in 2017, valued at more than Cdn$30 billion combined, involved the Kai Kos Dehseh (KKD), Foster Creek Christina Lake (FCCL), and AOSP ventures. Summaries of these acquisitions are as follows:

- In January 2017, Statoil Canada Ltd. (Statoil) completed the sale of its wholly owned KKD Leismer demonstration plant and undeveloped KKD Corner project, as well as its midstream assets, to Athabasca Oil Corporation for over Cdn$800 million in order to retain financial flexibility and focus on its core assets. Both Leismer and Corner have regulatory approvals in place to allow for expansions of up to $6.4 \times 10^3 \text{ m}^3/\text{d}$ (40.0 $10^3$ bbl/d).

- In May 2017, ConocoPhillips completed the sale of its 50 per cent nonoperated interest in the FCCL, as well as its Narrows Lake and western Canadian Deep Basin assets, to Cenovus for about Cdn$17.7 billion. The sale makes Cenovus the single largest thermal oil sands producer in Canada and allows the company to expand production at these assets independently because it has full regulatory approval at these in situ schemes. Cenovus has started selling off some of its conventional oil and gas assets to repay debt taken on to cover the costs of this transaction, but it will likely retain the liquids-rich Deep Basin assets to supply diluent for transportation. Although ConocoPhillips sold off its role in FCCL to reduce its own debt and production costs, the company retains a limited role in Alberta’s oil sands as it continues to operate its 50 per cent stake in the Surmont thermal project in partnership with Total E&P Canada Ltd. (Total).

- In May 2017, CNRL completed its acquisition of Shell’s operating interest in the AOSP, formerly jointly owned by Chevron Canada Ltd. (Chevron) and Marathon Oil (Marathon). A second transaction involved CNRL and Shell jointly purchasing Marathon’s 20 per cent share, ultimately leaving Shell with a 10 per cent interest, Chevron with a 20 per cent interest, and CNRL with a 70 per cent interest, as illustrated in Figure S3.4. The Cdn$12.7 billion deal comprises the Scotford upgrader (not including the Scotford refinery or chemical plants), Quest Carbon Capture and Storage project, and Muskeg River and Jackpine mines, and also includes the transfer of Shell’s working interests in other producing and nonproducing oil sands leases (Peace River complex). CNRL plans
to leverage mining efficiencies and economies of scale, while Shell will concentrate on operating refining, upgrading, and chemical plant assets.

In January 2018, Suncor and Teck Resources Ltd. (Teck) purchased greater working interests in the Fort Hills project from Total. Suncor increased its stake from 50.80 per cent to 53.06 per cent at a cost of about Cdn$300 million, and Teck’s share increased from 20.00 per cent to 20.89 per cent at a cost of Cdn$120 million. This deal was prompted by a dispute among the operating partners about Total’s reluctance to invest an additional Cdn$1 billion to accelerate construction on the Cdn$17 billion project due to the company’s interest in reducing its stake in the oil sands and its capital expenditures.
Fort McMurray Wildfires

Figure S3.5
Fort McMurray Wildfires, 2016

- **Area impacted by fire**
- **In situ schemes**
- **Rivers**
- **Surface mineable area**
- **Mining schemes**
- **Roads**
Wildfires that began to the southwest of Fort McMurray quickly grew and spread, prompting a local state of emergency beginning on May 1, 2016. The Horse River Fire, which colloquially became known as the Fort McMurray wildfires, eventually covered about 590,000 hectares. More than a dozen operating oil sands schemes near the wildfires, shown in Figure S3.5, were affected as companies wound down operations to safely evacuate employees and residents in the area. Efforts by emergency personnel, along with favourable weather in June, led to the wildfires being declared under control on July 4.

Although a number of in situ schemes were affected by the wildfires and lingering smoke, Suncor’s and Syncrude’s large-scale mining and upgrading assets suffered the greatest impact to production volumes due to their close proximity to the wildfires. At the wildfires’ peak, the AER estimates that about $250 \times 10^3 \text{ m}^3/\text{d}$ (1.5 million \[10^6\] bbl/d) of raw production and $100 \times 10^3 \text{ m}^3/\text{d}$ (660 \[10^3\] bbl/d) of upgraded production were taken offline. Total raw production lost over the duration of the wildfires was estimated to be about $4.8 \times 10^6 \text{ m}^3$ (30 \[10^6\] bbl).

**Petroleum Coke Production**

- In 2017, coke inventories reached 113 million tonnes, up 7 million tonnes from 2016. As shown in Figure S3.6, inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders; however, this has been followed by a trend of rising stockpile inventories related to increased SCO production at upgraders.
- About 90 per cent of coke produced at oil sands mines is stored in pits; most operators intend to eventually use the stockpiled coke in reclamation processes.

Oil sands petroleum coke, also referred to as “pet coke” or just “coke,” is a by-product of upgrading and is mostly stockpiled in Alberta. It is high in sulphur but has lower ash content than conventional crude oil petroleum coke. Suncor, Syncrude, and CNRL operate oil sands mines near Fort McMurray that use upgrading processes that produce coke; Nexen historically
produced limited amounts of coke from its OrCrude gasification process at its Long Lake facility, but it did not produce any in 2017 due to its suspended operation. Shell relies exclusively on hydrocracking technology, which does not produce coke as a by-product. Statistics of coke inventories reported in ST39: Alberta Mineable Oil Sands Plant Statistics show increases in the total closing inventories per year, as illustrated in Figure S3.6.

At CNRL’s Horizon project, all coke produced is stockpiled, accounting for just under 10 per cent of total coke inventories in 2017. About half of all coke produced in 2017 came from Suncor’s operations. Suncor has burned small amounts of coke in its boilers for decades at its mine near Fort McMurray, with about 11 per cent of its annual coke production used for site fuel in 2017. In response to provincial and national climate policies, Suncor has proposed its Coke Boiler Replacement Project, which would replace three of its coke-fired boilers with two natural gas-fired cogeneration units capable of supplying 700 megawatts (MW) of power to Alberta’s electricity grid. The company continues to evaluate the project, with an investment decision targeted for the end of 2018 and commissioning by 2022.

Syncrude, which produced about 25 per cent of all coke output in 2017, reported that about 20 per cent of its coke production was used as site fuel, similar to 2016. Syncrude is considering moving a petroleum coke pilot project at its Mildred Lake operation towards commercial use in 2018. The project allows water from tailings to return safely to rivers by filtering out suspended solids and absorbing organics.

**Crude Bitumen Well Activity**

As shown in Figure S3.7, the number of producing bitumen wells increased along with in situ crude bitumen production from 3088 wells in 1995 to 12 859 in 2017. Between 2016 and 2017, there was an increase of 416 wells.
As shown in Figure S3.8, 70.6 per cent of in situ production used steam-assisted gravity drainage (SAGD), 15.7 per cent used cyclic steam stimulation (CSS), and 13.7 per cent used primary production in 2017. SAGD production, including experimental schemes, increased by 18.2 per cent and was responsible for 27.0 thousand cubic metres per day ($10^3$ m$^3$/d) of the total growth in production between 2016 and 2017.

Average annual productivity of all in situ bitumen wells increased 8.7 per cent from 2016, reaching 19.3 m$^3$/d in 2017; average well productivity by recovery method is shown in Figure S3.9.
Crude Bitumen Demand

Upgraded and Nonupgraded Bitumen

In 2017, the four operating refineries in Alberta, with a total capacity of 73.5 thousand cubic metres per day ($10^3 \text{ m}^3/\text{d}$)—462.5 thousand barrels per day ($10^3 \text{ bbl/d}$)—processed an estimated $50.1 \times 10^3 \text{ m}^3/\text{d}$ ($315.3 \times 10^3 \text{ bbl/d}$) of upgraded bitumen and $2.7 \times 10^3 \text{ m}^3/\text{d}$ ($17.0 \times 10^3 \text{ bbl/d}$) of nonupgraded bitumen.

As shown in Figure S3.10, total estimated Alberta demand for upgraded and nonupgraded bitumen was $59.5 \times 10^3 \text{ m}^3/\text{d}$ ($374.4 \times 10^3 \text{ bbl/d}$) in 2017, which is a 7.6 per cent increase from 2016. The increase was primarily due to recovery from the Fort McMurray wildfires.

Alberta demand for upgraded and nonupgraded bitumen is forecast to increase to $72.9 \times 10^3 \text{ m}^3/\text{d}$ ($458.8 \times 10^3 \text{ bbl/d}$) by 2027.

On average over the forecast period, upgraded bitumen will account for about 82.0 per cent of total Alberta marketable bitumen demand, with nonupgraded bitumen accounting for the remainder.

In 2017, removals of upgraded bitumen and nonupgraded bitumen were estimated to be $103.0 \times 10^3 \text{ m}^3/\text{d}$ ($648.2 \times 10^3 \text{ bbl/d}$) and $247.2 \times 10^3 \text{ m}^3/\text{d}$ (1.6 million $10^6 \text{ bbl/d}$), respectively. Upgraded bitumen exports increased 7.3 per cent from 2016 due to production increases from upgraders outpacing provincial refinery demand.
Removals of upgraded bitumen from Alberta are expected to increase by 28.3 per cent to 132.1 \(10^3\) m\(^3\)/d (831.3 \(10^3\) bbl/d) between 2017 and 2027, while removals of nonupgraded bitumen are expected to increase 54.0 per cent to 380.8 \(10^3\) m\(^3\)/d (2.4 \(10^6\) bbl/d) over the same period.

Beyond the addition of the North West Redwater Partnership Sturgeon refinery (Sturgeon refinery) and an amended application to redesign the Value Creation Inc. (VCI) Heartland Upgrader project, there will be limited growth in Alberta demand for raw bitumen over the forecast period. Removals of nonupgraded bitumen are expected to increase over the forecast period.

The first phase of the Sturgeon refinery is projected to begin commercial operations in early 2018 and will be capable of handling up to 7.9 \(10^3\) m\(^3\)/d (50.0 \(10^3\) bbl/d) of raw bitumen. This phase is designed to produce about 6.4 \(10^3\) m\(^3\)/d (40.3 \(10^3\) bbl/d) of ultra-low sulphur diesel, 4.5 \(10^3\) m\(^3\)/d (28.3 \(10^3\) bbl/d) of diluent and naphtha, 1.4 \(10^3\) m\(^3\)/d (8.8 \(10^3\) bbl/d) of low-sulphur vacuum gas oil, and 0.5 \(10^3\) m\(^3\)/d (3.1 \(10^3\) bbl/d) of butane and propane. While second and third phases are planned, each with identical capacity to the first phase, their development depends on the first phase being commercially viable.

VCI previously received approval for its three-phase Heartland Upgrader project, also known as the Value Chain Solutions Heartland Complex (VCS-H). VCS-H would produce a sour synthetic medium crude oil using its Accelerated DeContamination (ADC) and Clean Oil Cracking (COC) processes. VCI has submitted an amendment application to replace the second of the three phases with two Clean Oil Refining (CORe) units to produce diesel, hydrotreated naphtha, and premium synthetic crude oil supplied from its COC stream, known as Clean Oil La Fit (COLF). Under an alternative development scenario, the second phase would be able to process product from VCI’s own offsite in situ projects. A reduction in the number of phases will reduce the diluted bitumen throughput capacity of VCS-H from 41.4 \(10^3\) m\(^3\)/d (260.5 \(10^3\) bbl/d) to 27.6 \(10^3\) m\(^3\)/d (173.6 \(10^3\) bbl/d). Subject to regulatory approval, VCI plans to begin construction of the first phase of VCS-H in 2018 and operation in 2021, with construction of the remaining phase and refining infrastructure scheduled to follow thereafter subject to market conditions.

Husky Energy’s (Husky’s) asphalt refinery located in Lloydminster, Alberta, processes heavy oil used in producing road asphalts. The refinery also produces condensate and refined petroleum products that are processed at Husky’s adjacent upgrader located in Lloydminster, Saskatchewan. To handle its growing production from heavy oil and thermal assets, Husky considered doubling the capacity of its 4.8 \(10^3\) m\(^3\)/d (30.0 \(10^3\) bbl/d) refinery for a cost of up to Cdn$900 million. However, the company has deferred that financial decision past 2020 following the acquisition of a 7.9 \(10^3\) m\(^3\)/d (50.0 \(10^3\) bbl/d) heavy oil refinery in Wisconsin, which it purchased in August 2017 for about Cdn$550 million.

Currently, Alberta’s crude bitumen removals are primarily sent to the United States via pipeline and rail. Information on the province’s petroleum pipelines and rail terminals can be found in the
Transportation and Facilities section. While Alberta's bitumen exports currently meet U.S. refinery demand, light oil production in U.S. supply basins may result in a loss of U.S. refinery capacity available to process Alberta’s upgraded (lighter) bitumen.

Heavy oil refineries located in the U.S. Midwest and Gulf Coast areas could potentially convert their processing capabilities to lighter feedstocks, which would significantly reduce refining opportunities for Alberta's nonupgraded bitumen. However, complex refineries, which are predominant in these regions and capable of handling nonupgraded bitumen, typically have multibillion dollar capital costs and favour discounted crude supplies, suggesting long-term demand for Alberta’s bitumen exports will persist. Previous challenges to investment in Mexican heavy oil exports and international sanctions against Venezuela during 2017 resulted in Alberta’s bitumen being viewed as a competitive and secure source of oil.

**Crude Bitumen Methodology**

**2017 Estimates**

All values for 2017 demand have been estimated using data reported by industry up until the end of August 2017. Full-year estimates for 2017 were derived using these data, adjusting for seasonality. All other 2017 figures, namely production and well counts, have been revised with actuals in the July 2018 update.

**Supply Cost**

The minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, as well as to earn a specified return on investment. The supply cost calculation determines a dollar value required per unit of production. For steam-assisted gravity drainage (SAGD) and standalone mining, this calculation gives a bitumen price at the wellhead per barrel. For a more meaningful comparison, the supply cost has been converted to a West Texas Intermediate (WTI) price, which accounts for transportation costs and exchange rates. This price can then be compared with current market prices to assess whether a project or resource is economically attractive. It can also be used to compare projects.

**Assumptions**

Although each project is unique in its location and the quality of its reserves, the supply cost analysis relies on generic project specifications and capital and operating cost estimates.

The generic projects represent proposed project types, including in situ SAGD (with and without cogeneration) and standalone mining with cogeneration. An integrated mine was not considered for this analysis because there are currently no proposed integrated bitumen projects in Alberta. Although significant production currently comes from cyclic steam stimulation (CSS) projects, few new CSS projects have been proposed; therefore, supply costs have not been determined for this recovery method. SAGD capital costs cover a wide range, with the lower range
representing capital costs for additional phases where portions of the infrastructure are already in place and the upper range representing capital costs for greenfield projects.

A major component of operating costs is natural gas purchased for fuel and feedstock. The supply cost analysis uses the forecast for AECO-C over a project’s 30- to 40-year life. For 2017 and beyond, the analysis assumes a nominal discount rate of 10 per cent.

The Province of Alberta presented its Royalty Review Advisory Panel Report in January 2016. The review concluded that the previous royalty framework for oil sands was appropriate for pre- and post-payout allowances. As a result, royalty calculations for oil sands supply costs have not changed for the calculation of supply costs in 2017.

Production

Mined Bitumen

Potential production from existing facilities and supply from future projects are considered in Table S3.4. Production from future mining projects considers the cost of engineering and materials and the substantial amount of skilled labour required to expand existing projects and build new ones. The forecast also recognizes that other key factors, such as the forecast of oil prices and the length of the construction period, will affect project timing. In preparing the forecast, projects that have been approved or applied for are assessed for the likelihood of meeting the on-stream date and anticipated volumes. This involves weighing the risks for each project. Some projects, though considered, will ultimately not be included in the ten-year forecast due to the high level of uncertainty about whether they will come on stream in the next decade.

In Situ Bitumen

Similar to surface mining, the supply forecast of in situ bitumen includes production from existing projects, expansions to existing projects, and new projects. All approved and applied for projects have been considered, as listed in Table S3.5, and the forecast assumes that all existing projects will continue producing at their current production levels over the forecast period. Projects considered for the forecast are assessed for the likelihood of meeting the on-stream date and volumes. This involves weighing the risks for each project. Some projects, though considered, will ultimately not be included in the ten-year forecast due to the high level of uncertainty about whether they will come on stream in the next decade.

The production forecast for future crude bitumen projects takes into account past performance of similar schemes, project modifications, crude oil prices and natural gas prices, light crude and bitumen price differentials, and the ability of North American markets to absorb increased volumes. The production forecast does not consider future export pipeline capacity since the AER does not have authority over approving pipelines that cross provincial or international
borders. Factors that may affect the pace of development, such as the availability of labour and equipment, were considered in the forecast.

Upgraded Bitumen

Table S3.6 lists all future projects in the forecast. Production from future upgrading projects considers the cost of engineering and materials and the substantial amount of skilled labour required to expand existing projects and build new ones. The forecast also accounts for other key factors, such as crude oil price forecasts, the price differential between light crude oil and bitumen, the length of the construction period, and the market penetration of new upgraded volumes, which will affect project timing.

The AER uses crude bitumen production volumes submitted by operators to PETRINEX in the forecasts. PETRINEX is a secure, centralized information network used to exchange petroleum-related information.