The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP’s member companies produce about 80 per cent of Canada’s natural gas and crude oil. CAPP’s associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP’s members and associate members are an important part of a national industry with revenues from oil and natural gas production of about $101 billion a year.

CAPP’s annual Crude Oil Forecast, Markets and Transportation report provides a long-term outlook for Canadian crude oil production, and this year is projecting serious constraints over the forecast period from 2019 to 2035.
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The constrained basin is directly connected to Canada's energy sector, regulatory and policy challenges, and insufficient market access, which in turn are having and will continue to pose negative implications throughout Canada's economy – from diminishing investment to loss of employment and reduced throughput tax and royalties.

Canada has an opportunity to gain global market share, replacing oil sustainability with global oil. At the same time, its healthy Canadian producers with access to global markets can continue achieving ongoing profitability and economic benefits across the country. However, the industry continues to face numerous challenges. If these challenges are not successfully addressed, any meaningful increase in oil production will not be achievable, ultimately reducing potential growth in Canada's gross domestic product (GDP), business investment, exports, and jobs.

Industry Competitiveness

Efficient and optimal global regulations are vital for the global competitiveness of Canada’s crude industry. The Canadian oil sands industry is set to post its fifth consecutive annual decline in investment. The continued regulatory and policy challenges create significant barriers to future investment, putting Canadian jobs at risk.

Market Access

Major pipeline projects such as Northern Gateway and Energy East have been cancelled, and the Enbridge Line 3 Replacement project is facing an uncertain future. The TransCanada proposals for the Enbridge Line 3 Replacement and TC Energy Keystone XL project continue to face challenges. All three pipeline projects were delayed in 2018 while price differentials reached record highs, resulting in the Alberta government implementing a production cutback program.

As a result, Canadian producers are facing insufficient takeaway capacity for crude oil. This limits Canada’s ability to serve existing markets in Canada and the U.S., and prevents Canada from accessing emerging overseas markets. The lack of sufficient pipeline capacity has forced Canadian producers to increasingly rely on rail to get crude to market. This is neither a long-term nor comprehensive solution to the lack of pipeline capacity.

The continued regulatory and policy challenges will negatively affect investor confidence. CAPP believes will establish barriers to improved market access and competitiveness gap in investment. Additionally, while the U.S. has aggressively streamlined regulations and tax rates to promote its own oil industry, the competitiveness gap is being exacerbated by proposed Canadian federal legislation that will establish barriers in the global energy industry and tax rates to promote its own oil industry.

The lack of sufficient pipeline capacity is diminishing the global energy industry’s potential to gain global market share, replacing oil sustainability with global energy industry. At the same time, its healthy Canadian producers with access to global markets can continue achieving ongoing profitability and economic benefits across the country. However, the industry continues to face numerous challenges. If these challenges are not successfully addressed, any meaningful increase in oil production will not be achievable, ultimately reducing potential growth in Canada’s gross domestic product (GDP), business investment, exports, and jobs.

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Fair Market Value

Pipeline constraints and lack of market diversity also mean Canada is losing value for crude oil exports. Canadian producers are not benefiting from the global commodity price. The key to obtaining better value for our resources in global markets is to build new, as well as improve existing infrastructure, allowing Canadian energy to compete for emerging global markets.

Resolution of the energy industry’s supply and demand imbalance is essential to unlocking the future of Canada’s energy industry – and indeed to Canada’s future prosperity. Canada is in the unique position of having abundant natural resources but insufficient pipeline and other infrastructure to grow exports of Canadian oil to U.S. and global markets.

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TABLE OF CONTENTS

Executive Summary 1

Introduction 4

Crude Oil Production and Supply Forecast 4
2.1 Production and Supply Forecast Methodology
2.2 Canadian Production
2.3 Eastern Canada Production
2.4 Western Canada Production
2.4.1 Conventional
2.4.2 Oil Sands
2.5 Western Canada Supply
2.6 Crude Oil Production and Supply Summary

Crude Oil Markets 13
3.1 Canada
3.1.1 Western Canada
3.1.2 Eastern Canada
3.2 United States Key Refining Hubs
3.2.1 PADD II – Midwest
3.2.2 PADD III – U.S. Gulf Coast
3.3 International
3.3.1 IMO Impact
3.4 Market Summary

Transportation 20
4.1 Crude Oil Pipelines Exiting Western Canada
4.2 Proposed Pipeline Systems
4.2.1 Line 3 Replacement Program
4.2.2 Trans Mountain Expansion Project
4.2.3 Keystone XL
4.3 Crude by Rail
4.4 Industry Growth Outside of Canada
4.5 Transportation Summary

Glossary 32

Appendices 34

LIST OF FIGURES

Figure 1.1 Capital Investment in the Oil Sands 2
Figure 2.1 Canadian Oil Sands and Conventional Production 5
Figure 2.2 Newfoundland and Labrador Production 6
Figure 2.3 Western Canada Conventional Crude Oil Production 8
Figure 2.4 Western Canada Pentanes and Condensate Production 8
Figure 2.5 Oil Sands Regions 9
Figure 2.6 Western Canada Oil Sands Production 9
Figure 2.7 Western Canada Oil Sands and Conventional Supply 11
Figure 3.1 Canada and U.S. 2018 Crude Oil Receipts by Source 13
Figure 3.2 PADD II 16
Figure 3.3 PADD III 17
Figure 3.4 International Oil Demand 18
Figure 4.1 Major Existing and Proposed Canadian and U.S. Crude Oil Pipelines 20
Figure 4.2 Enbridge Line 3 Replacement Project 23
Figure 4.3 Trans Mountain Expansion Project 25
Figure 4.4 TC Energy Keystone XL 27
Figure 4.5 Canadian Fuel Oil and Crude Petroleum Moved by Rail 28
Figure 4.6 Global Investment in Upstream Crude Oil and Natural Gas 30
Figure 4.7 Recently Constructed and Under Construction Permian Basin Pipelines 30
Figure 4.8 Existing Takeaway Capacity from Western Canada vs. Supply 31
In this, the 2019 edition of the Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers (CAPP) provides a constrained outlook for Canadian oil production from 2019 to 2035, as producers face a broad and increasing array of challenges. If these challenges are not successfully addressed then any meaningful increase in oil production will not be achievable, ultimately reducing potential growth in Canadian GDP, business investment, exports, and jobs. Oil supply in Western Canada already exceeds the transport capacity of pipelines to serve external markets, with the result that Canadians are not receiving the full value for our resources. While rail will play an increasingly important role in transporting western Canadian crude oil to regional refinery centres, significant additional pipeline capacity is needed for the Canadian industry to capture growing oil demand.

In addition to meeting regional market opportunities in the United States, with improved takeaway capacity Canadian producers would have the ability to serve global markets and fully realize Canada’s enormous resource potential. Improved pipeline capacity would allow Canadian producers to deliver increased volumes of heavy crude oil to the U.S. Gulf Coast at a time when other suppliers, such as Mexico and Venezuela, are reducing production of these crude varieties. Pipeline access from Western Canada to tidewater would provide Canadian producers with access to global markets, such as the Asia Pacific region, where growth in refinery feedstock demand is expected to be significantly higher than in North America. The ability for western Canadian crude oil to gain market share and to meet future increasing oil demand depends on the successful completion of new pipeline projects. The current lack of certainty of timing and confidence in completion of current pipeline projects, layered with additional regulatory issues, has led to a constrained production outlook.

Due to transportation costs and crude quality differences, heavier crude oils in Western Canada, such as Western Canadian Select (WCS), should typically expect to trade at a discount of about US$12 per barrel against West Texas Intermediate (WTI), the North American crude oil benchmark which is traded at Cushing, OK. Approximately half of this discount is the result of quality differences between heavy and light oil; the remainder reflects the need for Canadian crude to be transported long distances to serve U.S. refineries. At times in 2018, however, this crude oil price differential exceeded US$50 per barrel. This significantly larger differential was symptomatic of the lack of pipeline access out of the Western Canadian Sedimentary Basin (WCSB). Unable to find sufficient transportation for their production, producers consequently sold crude volumes at distressed prices, reducing producer revenues, government taxes and royalties collected, and hindering future investment. Surging levels of storage in Western Canada were also the result of a lack of transportation alternatives out of the region.

Other heavy oil producing countries are facing production declines due to aging infrastructure and geopolitical turmoil. This reduction in supply is leading to a better pricing environment for heavy crude in markets such as the U.S. Gulf Coast where refineries are capable of processing heavy crudes. Canada is missing an opportunity not only to gain market share but also to receive premium pricing for our resources.

In response to the significant price differentials in the fall of 2018, the Alberta government enacted its Crude Oil Curtailment Program that established limits on the volumes operators can produce in the province during 2019. The program’s intent is to reduce aggregate production from the WCSB to a level that should allow producers to draw down storage while fully utilizing current egress capacity from Western Canada. Draining high inventories of crude that have built up while egress capacity from the basin has lagged production was seen by the government to be a critical component of correcting the large price differentials that emerged in the second half of 2018. Following the implementation
exports directly tied to the oil and natural gas industry. Canadian GDP has been reduced due to lack of business investment and falling spending in the oil sands is forecast to decline for a fifth consecutive year to $12 billion, which is approximately one-third of the investment levels seen in 2014 (Figure 1.1). Yet, investment continues to be reduced due to pipeline delays, regulatory issues and reduced competitiveness. Producers need certainty and defined timelines. Without these assurances, the global competitiveness of Canada’s oil industry will be diminished, creating a significant barrier to future investment and putting Canadian jobs at risk. Potential federal legislation that would shift project approvals into the federal realm would slow new developments, leading to even less investment and fewer jobs. Without new pipeline capacity, producers are forced to move their product to markets using higher cost options such as rail, thereby driving up the discount in western Canadian oil prices.

Figures 1.1: Capital Investment in the Oil Sands

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<td>C$ BILLIONS</td>
<td>33.9</td>
<td>23.8</td>
<td>15.4</td>
<td>13.8</td>
<td>13</td>
<td>12</td>
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</tbody>
</table>

Production from oil sands projects, which involve substantial long-term financial commitments, are key drivers in the future growth prospects for Canadian crude oil production. Companies have adjusted to the lower price oil environment by substantially reducing their cost structure by anywhere from 35 to 55 per cent. Yet, investment continues to be reduced due to pipeline delays, regulatory issues and reduced competitiveness. Producers need certainty and defined timelines. Without these assurances, the global competitiveness of Canada’s oil industry will be diminished, creating a significant barrier to future investment and putting Canadian jobs at risk. Potential federal legislation that would shift project approvals into the federal realm would slow new developments, leading to even less investment and fewer jobs. Without new pipeline capacity, producers are forced to move their product to markets using higher cost options such as rail, thereby driving up the discount in western Canadian oil prices.

There is an increased interest regarding environmental, social and governance (ESG) practices in Canada. Oil producers are committed to ESG with an understanding that for the energy sector the (E) Environment is a focal priority. Companies are committed to lowering GHG emissions while minimizing other environmental impacts, in line with corporate goals of cost control, operating efficiently and being sustainable community partners. Good governance drives strong environmental and social practice – both corporately and from a jurisdictional perspective. Canada and Canadian companies consistently rank among the highest in international ESG scores. Company focus and disclosure on ESG performance demonstrates awareness and management of material business risks and priorities for organizations.

A variety of research indicates that the oil sector is, in fact, a global leader in ESG practices, especially in the technology and innovation space:

- The average emissions intensity of oil extraction has fallen 21 per cent since 2009. Oil sands life-cycle emissions are nearing North American average values.
  - By 2030, new technologies and efficiencies deployed in the oil sands could result in up to a 27 per cent reduction in the GHG intensity of steam-assisted gravity drainage operations and up to a 20 per cent reduction in the GHG intensity of mined oil sands.
  - On a full life-cycle basis (emissions from production to combustion), such intensities would place these sources within two to four per cent, and five to seven per cent respectively, of the average emission intensity for crude oil refined in the U.S.
- The Canadian industry will reduce methane emissions by 45 per cent from oil and natural gas operations by 2025. Innovation and collaboration are hallmarks of the oil sands industry, which has established a number of organizations to fund research and share results. CAP’s report Competitive Climate Policy: Supporting Investment and Innovation (May 2018) states:
  - Canada’s Oil Sands Innovation Alliance (COSIA) launched in 2012, and as of March 2018 member companies shared more than 960 distinct technologies that cost more than $1.4 billion to develop.
  - Petroleum Technology Alliance Canada (PTAC) has launched more than 600 projects and has a roster of about 100 active research projects aimed at technology development.
  - Clean Resources Innovation Network (CRIN) unites Canada’s resource industry, innovators, technology vendors, academia, research institutes, financing and government to accelerate the commercialization of innovative technologies. CAP’s report Toward a Shared Future: Canada’s Indigenous Peoples and the Oil and Natural Gas Industry (October 2018) found that:
    - Between 2011 and 2016, the Fort McKay Group of Companies (indigenous-owned businesses located in the oil sands region) generated more than $3.3 billion in revenue, which has supported the community in becoming self-determining and a strong, active participant in the oil sands industry.
    - In 2015 and 2016, oil sands companies spent $3.3 billion in procurement from indigenous-owned companies, provided $48.6 million in Indigenous community investment and created about 200 jobs.

A Joint Working Group (JWG) was convened in late 2017 as a forum for industry, federal and provincial governments to examine issues affecting competitiveness of Canada’s upstream oil and natural gas industry. According to the JWG report the Canadian upstream petroleum industry’s workforce is becoming increasingly diverse. For example: a doubling of visible minorities; an increase of immigrants, to about 16 per cent of the sector’s workforce; six per cent of the workforce are Indigenous peoples, compared to four per cent for Canada’s overall workforce.
CRUDE OIL PRODUCTION AND SUPPLY FORECAST

Over the next two decades, the world’s population is expected to grow by nearly two billion while the global middle class is expected to nearly double. Countries will be more urbanized and industrialized, and will consume more energy than today. Canada thus has the potential to become an even more significant supplier in meeting global crude oil demand. Canada is the world’s sixth-largest oil producer and is home to a vast 170 billion barrels of crude oil reserves. However, the path to realizing this potential is paved with challenges regarding uncertainty as to when or whether additional pipeline capacity will become available.

Total Canadian oil production, including pentanes and condensate, is expected to rise to 5.86 million barrels per day (b/d) by 2035 from 4.59 million b/d in 2018. Due to the need to supplement domestic diluent supplies with imported volumes, the total supply from Western Canada is forecast to grow to 6.3 million b/d by 2035 from 4.7 million b/d in 2018. For comparison, in 2014 CAPP projected total supply from Western Canada would grow to 7.5 million b/d by 2030. This year’s constrained production outlook is due to inefficient and duplicative regulations, reduced investor and producer confidence, and uncertainty around additional transportation capacity.

2.1 Production and Supply Forecast Methodology

CAPP's forecasts for western Canadian conventional production and eastern Canadian production were both developed through an internal analysis of historical trends, expected drilling activity, and discussions with industry stakeholders and government agencies. To forecast oil sands production, CAPP surveyed oil sands producers in the first quarter of 2019 requesting the following information:

- Expected production for each project;
- Upgraded crude oil production volumes;
- Type and volume of diluent required to move heavy oil production to market.

Producers were asked to respond to the survey based on their company’s view of the price outlook, as well as recent policy developments including federal and provincial climate policies and the impacts of Alberta’s Crude Oil Curtailment Program. The survey results were risk adjusted by taking into consideration each project’s stage of development, (i.e. announced, approved, under construction, operating) while giving consideration to each company’s past performance for previous phases of projects relative to public announcements. The reasonableness of the overall forecast was then assessed against historical trends. No constraints were imposed to reflect any restrictions on the availability of condensate for blending purposes or the lack of transportation infrastructure, although company assessments on these issues may have impacted individual producer survey responses.

The volume of total crude oil supplied delivered to pipelines and markets is greater than total production because imported diluent, in addition to domestic supplies, is needed to meet the blending requirements that enable heavy oil to be transportable by pipeline.

2.2 Canadian Production

Conventional crude oil is produced across the western Canadian provinces while the oil sands are located only in Alberta. Eastern Canada produces limited amounts of crude oil primarily from projects located offshore of Newfoundland and Labrador. At its peak, Hebron is designed to produce 150,000 b/d.

Table 2.1 Canadian Crude Oil Production

<table>
<thead>
<tr>
<th></th>
<th>2018</th>
<th>2020</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern Canada</td>
<td>0.23</td>
<td>0.30</td>
<td>0.32</td>
<td>0.18</td>
<td>0.09</td>
<td>-0.14</td>
</tr>
<tr>
<td>Western Canada</td>
<td>4.36</td>
<td>4.64</td>
<td>5.17</td>
<td>5.48</td>
<td>5.76</td>
<td>1.41</td>
</tr>
<tr>
<td>Total Canada*</td>
<td>4.59</td>
<td>4.94</td>
<td>5.49</td>
<td>5.66</td>
<td>5.86</td>
<td>1.27</td>
</tr>
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</table>

*Totals may not add up due to rounding.

Production in Eastern Canada is forecast to peak at 354,000 b/d in 2026 before falling to roughly 91,000 b/d in 2035. Production growth in Western Canada is expected to more than offset this decline, as it is forecast to increase by more than 1.4 million b/d, reaching 5.76 million b/d in 2035 from 4.36 million b/d in 2018 (Table 2.1).

2.3 Eastern Canada Production

Ontario and New Brunswick produce small volumes of crude oil; however, most of the crude oil from Eastern Canada is produced from offshore Newfoundland and Labrador. Hibernia, Terra Nova, White Rose and Hebron are the four major offshore projects currently producing oil. The growth forecast for production in Eastern Canada through 2024 can largely be attributed to production ramping up from Hebron, the newest major offshore project, and satellite field additions to other existing projects. At its peak, Hebron is designed to produce 150,000 b/d.
Conventional production, including pentanes and condensate, will be slightly more productive through 2024 than previously projected.
2.4.2 Oil Sands

The oil sands resources are situated almost entirely in Alberta and can be delineated by the Athabasca, Cold Lake and Peace River deposits (Figure 2.5). In this constrained environment, oil sands production, which can be recovered either by mining or in situ projects, is forecast to grow by 1.34 million b/d, reaching 4.25 million b/d by 2035 from 2.91 million in 2018. From 2019 to 2021, annual oil sands production growth is expected to average four per cent. This growth rate, however, is less than half that of 2017 and 2018. Given the current regulatory environment and producers’ lack of confidence in market access alleviation, from 2022 onward the average production growth in the oil sands is expected to be only two per cent annually.

Mining projects are large-scale in nature and require more upfront capital than smaller scale in situ projects, where production can be brought on in phases. The Fort Hills mining project started continuous production in January 2018 and ramped up to just over 200,000 b/d in December. By 2035, production from mining operations will grow by 470,000 b/d (Table 2.4). In situ production is forecast to yield 880,000 b/d of additional production (Figure 2.6) by 2035. Part of this includes CNOOC International’s expansion at Long Lake, proposed to add 26,000 b/d, and Imperial Oil Limited’s Aspen project, which Imperial expects will begin production in 2023 and add 75,000 b/d.

Pentanes and Condensate

Pentanes and condensate are the preferred diluent for blending with heavy oil and bitumen to enable transportation via pipeline. In 2018, 405,000 b/d of pentanes and condensate were produced in Western Canada, with about 80 per cent contributed by Alberta and 20 per cent contributed by B.C. Demand for pentanes and condensate from oil sands for blending with bitumen exceeds domestic production and demand will continue to be driven by projected growth in heavy crude oil production. From 2014 to 2018, pentanes and condensate production more than doubled. This was due to the strong demand for diluent from oil sands producers and the presence of prolific liquids-rich natural gas plays in the Montney and Duvernay formations. Production of pentanes and condensate is forecast to grow significantly and achieve more than 600,000 b/d before the end of the forecast period. In the longer term, however, declines are anticipated as these fields mature.
Curtailment

In December 2018, the Government of Alberta announced its Crude Oil Curtailment Program that was applied to production commencing in January 2019 and will terminate on December 31, 2019. Initially the program limited production in Alberta to 3.56 million b/d with the intention to create enough shipping space to clear the large buildup of storage volumes that had occurred in the province. Once storage volumes have been substantially reduced, the program intends to allow higher production limits for the balance of 2019.

Curtailment is only applied to operator volumes in excess of 10,000 b/d and as such will have limited impacts on small producers. While these cuts may affect some of the larger conventional producers, the majority of the impact is expected to affect oil sands producers, which typically have larger scale developments. Responding to market conditions and producer concerns regarding the safety issues surrounding cutting production, the government raised the production ceiling for the month of June to more than 3.7 million b/d.

This policy is a direct result of continued regulatory delay resulting in a lack of market access. The dramatically lower pace of growth in production at the latter end of the forecast period, relative to recent history and the near-term outlook, is the product of the industry’s concerns around slow progress on new pipeline capacity and heightened levels of regulatory uncertainty. In addition, Canada’s fiscal and tax policies have substantially reduced, the program intends to allow higher production limits for the balance of 2019.

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The production volumes from oil sands projects are derived by combining raw bitumen production and upgraded crude oil production from integrated projects. By volume, there is generally a yield loss associated with the upgrading process, which converts mined bitumen into an upgraded (lighter) crude oil. The yield losses associated with upgrading volumes from oil sands projects without associated upgraders is accounted for in the calculation of supply volumes discussed in Part 2.5 below. Refer to Appendix A.1 for detailed production data.

Upgrading

Partial upgrading technology produces a medium or heavy crude oil that reduces the requirement for diluent volumes for blending. However, since partial upgrading technologies are still in use, they will continue to be considered in calculations of crude oil production and supply volumes. Imperial’s Kearl mine and Suncor’s newly operating Fort Hills mine are both stand-alone mines with no associated upgrading facilities. Partial upgrading technology produces a medium or heavy crude oil that reduces the requirement for diluent volumes. Some in situ volumes from Suncor’s Firebag and Mackay River projects can be upgraded at its Millennium mine upgrader but, in general, upgraders at smaller in situ operations are not considered economical.

The following is a list of the existing integrated mining and upgrading projects:

- Canadian Natural Resources’ (CNRL) Albian Sands, which includes the Muskeg River and Jackpine mines;
- CNRL’s Horizon mine;
- Suncor’s Steepbank and Millennium mines;
- Syncrude Canada’s Mildred Lake and Aurora mines.

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2.5 Western Canada Supply

Crude oil supply refers to the crude oil that is delivered to the end-use market. Conventional supply is projected to decline to 867,000 b/d in 2035 from 960,000 b/d in 2018. Upgraded light crude oil supply is expected to be stable and is forecast to average 948,000 b/d over the outlook period. Oil Sands heavy supply will grow by 1.52 million b/d to reach 4.5 million b/d in 2035 from 2.98 million b/d in 2018 (Figure 2.7).
Today nearly all of Canada’s oil exports are delivered to U.S. refineries. In 2018, Canada exported more than 3.6 million b/d to the U.S. – less than one per cent of exports were delivered to other markets. Domestic Canadian refinery markets account for about one million b/d, or 24 per cent of total demand for Canadian production.

The long-term pace of growth in the oil sands continues to be hampered by uncertainty and delays to new pipeline capacity out of Western Canada.
3.1 Canada

There are 17 refineries in Canada that have a collective crude oil refining capacity of 2.0 million b/d. In 2018, crude oil feedstock actually processed by Canadian refineries totaled more than 1.7 million b/d, including 593,000 b/d of imported oil.

3.1.1 Western Canada

The nine refineries located in Western Canada (Table 3.1) comprise approximately 40 per cent of Canada’s total crude oil refining capacity. Alberta and Saskatchewan refineries receive crude oil supplies exclusively from Western Canada, primarily by pipeline although some volumes are transported short distances by truck. Refineries in B.C. obtain some crude oil from within the province but most of B.C.’s supply comes from Alberta through the existing Trans Mountain pipeline, as well as some smaller volumes by rail. According to the NEB, less than 10 per cent of B.C.’s refined petroleum products are imported from the U.S.

<table>
<thead>
<tr>
<th>Owner</th>
<th>Location</th>
<th>Crude oil processing capacity (b/d)</th>
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<tbody>
<tr>
<td>Imperial</td>
<td>Strathcona</td>
<td>191,000</td>
</tr>
<tr>
<td>Husky (asphalt plant)</td>
<td>Lloydminster</td>
<td>290,000</td>
</tr>
<tr>
<td>Suncor</td>
<td>Edmonton</td>
<td>142,000</td>
</tr>
<tr>
<td>Shell</td>
<td>Scotford</td>
<td>92,000</td>
</tr>
<tr>
<td>North West Redwater Partnership</td>
<td>Sturgeon County</td>
<td>79,000 (dilbit)</td>
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<tr>
<td>Alberta subtotal (9 refineries)</td>
<td></td>
<td>530,000</td>
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</table>

<table>
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<tr>
<th>Owner</th>
<th>Location</th>
<th>Crude oil processing capacity (b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parkland Fuel</td>
<td>Burnaby</td>
<td>55,000</td>
</tr>
<tr>
<td>Husky</td>
<td>Prince George</td>
<td>12,000</td>
</tr>
<tr>
<td>British Columbia subtotal (2 refineries)</td>
<td></td>
<td>67,000</td>
</tr>
<tr>
<td>Federated Co-operatives</td>
<td>Regina</td>
<td>130,000</td>
</tr>
<tr>
<td>Gibson (asphalt plant)</td>
<td>Moose Jaw</td>
<td>18,000</td>
</tr>
<tr>
<td>Saskatchewan subtotal (2 refineries)</td>
<td></td>
<td>148,000</td>
</tr>
<tr>
<td>Total (9 refineries)</td>
<td></td>
<td>748,000</td>
</tr>
</tbody>
</table>

Western Canada refinery demand increased to 562,000 b/d in 2018 from 545,000 b/d in 2017 due to the start-up of Phase One of the North West Redwater Partnership’s Sturgeon Refinery, which commenced operations in late 2018. Since start-up, the refinery has processed synthetic crude oil to produce diesel. The refinery is working toward eventually processing heavier feedstocks; once construction of its gasifier is complete, the refinery will be able to use up to 50,000 b/d of bitumen or 79,000 b/d of dilbit as feedstock. This is the first refinery built in Canada since 1984 and has three potential expansion phases. Future expansions have received regulatory approvals but timing of the remaining phases is uncertain.

3.1.2 Eastern Canada

There are eight refineries in Eastern Canada with a combined crude oil refining capacity of 1.2 million b/d (Table 3.2). The capacity of these refineries exceeds the combined capacity of Canada’s western refineries by 464,000 b/d. Because eastern refineries are not as well connected to domestic crude oil production supplies, these refineries are currently less reliant on imported crude to meet their needs. Refineries in Eastern Canada process primarily light crude oil and in 2018 received approximately half of their 1.1 million b/d of feedstock from foreign sources.

Eastern refineries’ access to western Canadian supplies and U.S. Bakken production significantly improved after Enbridge reversed its Line 9 pipeline to flow west to east from Sarnia, Ontario to Montreal, Quebec. This reversal occurred in December 2015. Refineries in Quebec and Atlantic Canada have tidewater access and consequently have access to crude oil supplies from a number of global alternatives. Irving Oil’s refinery in Saint John, N.B. can receive some western Canadian crude oil by rail, but Atlantic Canada refineries primarily rely on foreign imports by tanker, supplemented by some Atlantic Canada production. The U.S. has been a large supplier of crude oil to Canada since 2013, and supplied about 65 per cent of the total import demand in 2018. Saudi Arabia is also a major exporter of crude oil to eastern Canadian refineries, supplying 21 per cent of total import demand in 2018. Other countries supplying crude oil to these refineries include Nigeria, Azerbaijan and Norway.

<table>
<thead>
<tr>
<th>Owner</th>
<th>Location</th>
<th>Crude oil processing capacity (b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Imperial</td>
<td>Nanticoke</td>
<td>113,000</td>
</tr>
<tr>
<td>Imperial</td>
<td>Sarnia</td>
<td>119,000</td>
</tr>
<tr>
<td>Shell</td>
<td>Sarnia</td>
<td>73,000</td>
</tr>
<tr>
<td>Suncor</td>
<td>Sarnia</td>
<td>85,000</td>
</tr>
<tr>
<td>Ontario subtotal (4 refineries)</td>
<td></td>
<td>390,000</td>
</tr>
<tr>
<td>Parkland Fuel</td>
<td>Montreal</td>
<td>137,000</td>
</tr>
<tr>
<td>Ultramar</td>
<td>Quebec City</td>
<td>23,000</td>
</tr>
<tr>
<td>Quebec subtotal (2 refineries)</td>
<td></td>
<td>372,000</td>
</tr>
<tr>
<td>Irving</td>
<td>Atlantic Canada</td>
<td>320,000</td>
</tr>
<tr>
<td>Silverpeak (North Atlantic Refining LP)</td>
<td>Come by Chance, NL</td>
<td>130,000</td>
</tr>
<tr>
<td>Atlantic subtotal (2 refineries)</td>
<td></td>
<td>450,000</td>
</tr>
<tr>
<td>Total (6 refineries)</td>
<td></td>
<td>1,212,000</td>
</tr>
</tbody>
</table>
3.2 United States Key Refining Hubs

Canada is the largest foreign supplier of crude oil to the U.S., delivering 3.7 million b/d in 2018, which accounted for almost all of Canada’s exports. Given its tremendous resource base, Canada has the potential to supply even larger volumes to the U.S. However, the ability to increase exports to this market is currently hampered by a lack of transportation capacity.

The U.S. Department of Energy divides the 50 states into five market regions called Petroleum Administration of Defense Districts (PADDs). These PADDs were originally created in the Second World War to help allocate fuels derived from petroleum products. Today, this delineation continues to be used when reporting data to describe U.S. crude oil markets, which have different characteristics attributable to their distinct regional locations.

3.2.1 PADD II – Midwest

Currently the largest regional market in the U.S. for Canadian crude oil exports is the Midwest. In 2018, this 3.8 million b/d refining market imported 2.5 million b/d, or 65 per cent of its crude oil feedstock needs (Figure 3.2) with almost all these imports originating in Western Canada. This heavy reliance on crude supplies from Western Canada is not surprising, as a number of refineries in PADD II have made significant investments in recent years to increase their ability to process heavy crude oil. Consequently, these refineries are expected to continue to rely almost exclusively on Western Canada for their heavy feedstock requirements, as they are well connected via pipeline to access crude oil from Western Canada.

PADD II also encompasses the largest commercial storage hub in the U.S. at Cushing, Oklahoma. Cushing is the main trading hub for U.S. crude oil and is also the delivery point for New York Mercantile Exchange (NYMEX) traded futures contracts. The Energy Information Agency reports there are approximately 77 million barrels of working storage capacity at this hub. Crude oil that is initially delivered to this hub can ultimately be delivered to markets outside PADD II when taken out of storage. In recent years, additional pipeline capacity has been developed that connects this hub to refineries on the U.S. Gulf Coast, which are located in PADD III. Other primary market hubs within PADD II are located at Clearbrook, Minnesota and Wood River-Patoka, Illinois. See Appendix C refinery map for locations.

3.2.2 PADD III - U.S. Gulf Coast

The U.S. Gulf Coast is home to a vast refinery complex that comprises 49 refineries with a combined capacity of 9.8 million b/d. The majority of this capacity is located in two coastal states, Louisiana and Texas.

Since 2010, U.S. consumption of domestic crude oil feedstock in the U.S. Gulf Coast has grown dramatically, as the U.S. has seen a significant increase in production from its own light shale oil resources. For example, since 2007 the Permian basin has seen a fourfold increase in production, from less than one million b/d in to more than four million b/d in early 2019. In 2018, domestic crude oil supplied 6.3 million b/d, or 69 per cent, of PADD III’s nine million b/d feedstock demand (Figure 3.3). In contrast, U.S. domestic supplies accounted for only 28 per cent of regional demand in 2010. Even though light sweet crude oil imports have now been largely displaced by domestic production as a result of the U.S. shale boom, significant demand for heavy oil supplies still remains. The U.S. Gulf Coast refinery complex has around two million b/d of heavy crude oil refining capacity.

While Venezuela and Mexico have traditionally been the dominant sources of heavy crude oil to the region, supplying 489,000 b/d (Venezuela) and 992,000 b/d (Mexico) in 2018, Canada has an opportunity to expand its share of this market. Today Canada is in third place, having supplied 480,000 b/d of heavy crude in 2018, but sharp declines in crude oil production in both Venezuela and Mexico mean refineries in PADD III are seeking other sources of feedstock supply. In November 2018, Mexican crude oil production was 1.86 million b/d, a decline of 22 per cent from production of 2.30 million b/d in January 2015. Production declines have been even more dramatic in Venezuela, with November 2018 production of 1.32 million b/d representing a decline of 47 per cent from 2.50 million b/d in January 2015.

Until the Keystone XL pipeline is available, the ability to replace supplies from Venezuela and Mexico will be challenging for Canadian producers. This is because Canadian producers must rely increasingly on rail, which incurs higher transportation costs and potentially requires crude oil to be sold at a substantial discount in order to capture market share.

3.3 International

World demand for crude oil is expected to grow in the coming decades and Canada’s ability to provide additional supplies to meet this higher demand will depend on its ability to build the required market access infrastructure. According to the International Energy Agency’s World Energy Outlook 2018 (New Policies Scenario), global oil demand is projected to increase 12 per cent from 94.8 million b/d to 106.3 million b/d by 2040. Overall, energy demand will decrease in mature economies, but this will be more than offset by increases that reflect developing economies catching up with mature economies. Per capita energy consumption in developing economies is expected to increase rapidly toward OECD levels as prosperity rises. The combined demand growth from China and India of 8.2 million b/d is equal to 70 per cent of the projected world demand increase from 2017 to 2040 (Table 3.3).

Table 3.3 Total Oil Demand in Major Asian Countries

<table>
<thead>
<tr>
<th></th>
<th>Million b/d</th>
<th>2017</th>
<th>2025</th>
<th>2030</th>
<th>2035</th>
<th>2040</th>
<th>2017 - 2040 Growth</th>
</tr>
</thead>
<tbody>
<tr>
<td>China</td>
<td>12.3</td>
<td>14.9</td>
<td>15.7</td>
<td>15.7</td>
<td>15.8</td>
<td>3.5</td>
<td></td>
</tr>
<tr>
<td>India</td>
<td>4.4</td>
<td>6.2</td>
<td>7.4</td>
<td>8.4</td>
<td>9.1</td>
<td>4.7</td>
<td></td>
</tr>
<tr>
<td>Japan</td>
<td>3.6</td>
<td>3.1</td>
<td>2.7</td>
<td>2.4</td>
<td>2.1</td>
<td>-1.5</td>
<td></td>
</tr>
<tr>
<td>SE Asia</td>
<td>4.7</td>
<td>6.6</td>
<td>6.4</td>
<td>6.7</td>
<td>6.8</td>
<td>2.1</td>
<td></td>
</tr>
</tbody>
</table>

*Values may not add up due to rounding.

Global oil demand is projected to increase 12 per cent by 2040.
3.3.1 IMO Impact

Upcoming changes to United Nations International Maritime Organization (IMO) regulations may have implications for the future demand of heavy, high-sulphur crude oils produced in Alberta's oil sands. The IMO has established new requirements for bunker fuel specifications that require sulphur emissions to fall from 3.5 per cent to 0.5 per cent by 2020. Global average bunker fuel sulphur content is currently about 2.45 per cent. In total, more than three million b/d of high sulphur fuel oil (HSFO) bunkers will need to switch to 0.5 per cent sulphur fuel through blending.

The IMO standards create an uncertain outlook for the broader global refining sector, especially regarding how refiners will respond to a more sulphur-constrained global bunker fuels market. Sweet/sour differentials and light/heavy differentials will likely widen during the initial years following the change in regulation, as there will be a higher premium on sweet crudes over those heavy sour crudes that yield relatively more volumes of heavy residual fuel oil (which is used as a bunker fuel) during the refining process. The magnitude and duration of this impact is highly uncertain and depends on some key variables such as compliance and scrubber (exhaust gas cleaning systems) uptake in the maritime industry, and blending opportunities available to refiners.

3.4 Market Summary

While there is significant incremental market potential for Canadian producers in both the U.S. and the Asia-Pacific region, uncertainty around the timing of any additional pipeline capacity continues to frustrate producers in pursuit of these new opportunities. Looking to the future, the bulk of Western Canada’s growing heavy crude oil supplies are ideally suited for the U.S. Gulf Coast market due to the size of that region's heavy oil processing capacity and uncertainty around existing suppliers to the region. As well, pipeline projects out of Western Canada would provide producers with much-needed market optionality and reduce reliance on a single export market. This is especially important given the fact that the global markets exhibiting the greatest potential for growth in crude oil consumption lie beyond the U.S. and are found in Asia.

Figure 3.4  International Oil Demand

Source: International Energy Agency’s World Energy Outlook, 2018

Uncertainty around the timing of any additional pipeline capacity continues to frustrate producers in pursuit of new opportunities.
A well-established network of pipelines connects western Canadian crude oil producers to the North American refinery market. As early as 1950 the Interprovincial Pipeline Company (now Enbridge) began shipping western Canadian crude oil to the U.S. This pipeline network was expanded as production of crude oil from Western Canada has grown and the demands of the market, resulting in producers facing substantial pipeline capacity constraints.

The existing pipeline infrastructure network shown in Figure 4.1 is able to transport crude oil produced in Western Canada to Canadian and U.S. refineries has increased. Yet in recent years, regulatory timelines for pipeline development have become prolonged and the pipeline network no longer keeps pace with the demands of the market, resulting in producers facing substantial pipeline capacity constraints.

The existing pipeline infrastructure network shown in Figure 4.1 is able to transport crude oil produced in Western Canada to Canadian and U.S. refineries has increased. Yet in recent years, regulatory timelines for pipeline development have become prolonged and the pipeline network no longer keeps pace with the demands of the market, resulting in producers facing substantial pipeline capacity constraints.

The combined nameplate capacity of major takeaway pipelines is more than four million b/d of crude oil from Western Canada. However, in 2018 about 635,000 b/d of capacity was unavailable as a result of equipment being offline, constraints on downstream pipelines, capacity being allocated for transporting refined petroleum products, and U.S. Bakken crude oil production taking up space otherwise available for western Canadian production (Table 4.1). In 2018, most of the 4.66 million b/d of western Canadian crude oil supplies were transported to markets by pipeline but excess volumes depended on rail. Refineries in Alberta and Saskatchewan that require delivery from a short distance may receive volumes from regional pipelines or trucks.

The price producers obtain for crude oil in any region is a function of the type of crude oil being produced and the transportation costs incurred for delivery from the production area. Pipelines are the preferred mode of shipping large volumes of crude oil long distances over land given the economics of scale. The associated costs of using rail is higher than pipelines or tankers over the same distance.

**4.1 Crude Oil Pipelines Exiting Western Canada**

At present, there is not enough crude oil capacity originating in Western Canada to meet the needs of producers. Both the Enbridge Mainline and Trans Mountain pipelines continue to operate under apportionment. This occurs when shipper nominations exceed the pipeline’s capacity, so pipeline operators are forced to decrease shippers’ nominated volumes on a pro-rata basis. The combined nameplate capacity of major takeaway pipelines is more than four million b/d of crude oil from Western Canada. However, in 2018 about 635,000 b/d of capacity was unavailable as a result of equipment being offline, constraints on downstream pipelines, capacity being allocated for transporting refined petroleum products, and U.S. Bakken crude oil production taking up space otherwise available for western Canadian production (Table 4.1). In 2018, most of the 4.66 million b/d of western Canadian crude oil supplies were transported to markets by pipeline but excess volumes depended on rail. Refineries in Alberta and Saskatchewan that require delivery from a short distance may receive volumes from regional pipelines or trucks.

### Table 4.1 Major Existing Crude Oil Pipelines Exiting Western Canada

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>In Service</th>
<th>Outside Diameter (inches)</th>
<th>Distance (km)</th>
<th>Average Annual Capacity (600 b/d)</th>
<th>2018 Annual Throughput (600 b/d)</th>
<th>Est. Capacity Available for Crude Oil Exiting WCSB (600 b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enbridge Mainline</td>
<td>Operating since 1990</td>
<td>Various</td>
<td>Various</td>
<td>2,611</td>
<td>2,629</td>
<td>2,307</td>
</tr>
<tr>
<td>Trans Mountain</td>
<td>Operating since 1983</td>
<td>24</td>
<td>1,147</td>
<td>300</td>
<td>290</td>
<td>270</td>
</tr>
<tr>
<td>Enbridge Express</td>
<td>Operating since 1997</td>
<td>24</td>
<td>1,265</td>
<td>280</td>
<td>249</td>
<td>250</td>
</tr>
<tr>
<td>TC Energy Keystone</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase 1</td>
<td>Operating since 2010</td>
<td>36</td>
<td>846</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase 2</td>
<td>Operating since 2011</td>
<td>30</td>
<td>2,592</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gulf Coast Extension</td>
<td>Operating since 2014</td>
<td>36</td>
<td>468</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Houston Lateral</td>
<td>Operating since 2016</td>
<td>36</td>
<td>90</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Notes for estimating available capacity for Canadian crude oil to exit Western Canada on the major pipelines:

- *Enbridge Mainline*: design capacity x 95% for operational downtime and downstream constraints minus estimated RPP capacity as well as estimates for U.S. Bakken moved on this system 2018 throughput source: NEB
- *Trans Mountain*: design capacity minus estimate of RPP moved = 300-30 = 270
- *Express*: design capacity x 89% (adjusted for crude type moved, technical operational constraints, and downstream constraints 2018 throughput source: Express Pipeline LLC FERC Form 4)
- *Keystone*: design capacity x 90% (adjusted for crude type moved and technical operational constraints)
Only three major pipeline projects remain under active development following the cancellation of the Energy East pipeline in October 2017 and Northern Gateway in November 2016. The combined capacity of Enbridge's Line 3 Replacement project, the Trans Mountain Expansion Project, and TC Energy's Keystone XL (Table 4.2) equals 1.79 million b/d. All of this capacity will be needed to meet the 1.68 million b/d of anticipated supply growth from Western Canada.

Table 4.2 Proposed Crude Oil Pipelines Exiting Western Canada
<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Outside diameter (inches)</th>
<th>Distance (km)</th>
<th>Target In service</th>
<th>Capacity (000 b/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enbridge Line 3 Replacement</td>
<td>36</td>
<td>1,659</td>
<td>2020</td>
<td>370</td>
</tr>
<tr>
<td>Trans Mountain</td>
<td>36</td>
<td>967 (new)</td>
<td>2020+</td>
<td>590</td>
</tr>
<tr>
<td>Expansion</td>
<td>36</td>
<td>3.6 x 2 (new)</td>
<td>24</td>
<td>193</td>
</tr>
<tr>
<td>TC Energy Keystone XL</td>
<td>36</td>
<td>1,897</td>
<td>2020+</td>
<td>830</td>
</tr>
</tbody>
</table>

Total Proposed Additional Capacity: 1,790

4.2 Proposed Pipeline Systems

The next sections summarize the three proposed pipelines.

4.2.1 Line 3 Replacement Program

Line 3 is one of the Enbridge Mainline’s primary pipelines. The original capacity of the line was 760,000 b/d but due to age and safety issues, since 2008 it has operated under voluntary pressure restrictions that have reduced its capacity to 390,000 b/d, and now requires extensive maintenance to operate even at this reduced level. The proposed Line 3 Replacement Program would replace the pipeline and restore it to its original capacity. This pipeline will be essential to ensure continued service required by refineries in Minnesota and neighbouring states, as well as Eastern Canada and the U.S. Gulf Coast.

The line was expected to be in service by the end of 2019 but with a delay in permits from the State of Minnesota the line will not be ready until the second half of 2020. On June 3 2019 the Minnesota Court of Appeals ordered further proceedings to consider the potential impact of an oil spill into the Lake Superior watershed.

Successful completion of L3RP will put an additional 370,000 b/d of Canadian oil on the global market.
4.2.2 Trans Mountain Expansion Project

The Government of Canada issued an Order-in-Council to approve the Trans Mountain Expansion Project (TMMEP) in November 2016. Prior to that, in May 2016, the NEB determined the project was in the Canadian public interest and recommended approval of the expansion. In January 2017 the B.C. Environmental Assessment Office issued an environmental assessment certificate for the project.

The expansion essentially involves twinning the existing pipeline between Edmonton, Alberta and Burnaby, B.C. and will increase capacity from 300,000 b/d to 890,000 b/d.

In August 2018 the Federal Court of Appeal issued a decision to cancel the Order-in-Council, which had approved the Certificate of Public Convenience and Necessity for the expansion project. The NEB held public hearings to reconsider project-related environmental effects of marine shipping and further engagement with Indigenous groups. In February 2019 the NEB delivered its reconsideration report to the Government of Canada; the NEB again recommended approval of the project finding it to be in the Canadian public interest. The project is subject to 156 conditions enforceable by the NEB.

In April 2019, the Government of Canada announced that a decision on TMMEP will be made June 18, 2019. CAPP expects a positive decision that will have enormous positive impacts on the Canadian economy by helping to alleviate market access constraints, resulting in increased producer and investor confidence, increased business investment and Canadian jobs, and an increase in exports. Construction beginning in the summer of 2019 should have the expansion in service by late 2022. Delays in the construction of TMMEP cost Canadians $693 million every year.8

With improved market access, the Alberta government expects an incremental $10 billion in oil sands investment is possible in the short term, leading to incremental production of 190,000 barrels per day of bitumen. This would increase the size of Alberta’s economy alone by 1.5 to two per cent by 2023.9

That investment in oil sand facilities would also create and sustain an average of 12,300 direct, indirect, and induced jobs across Canada through 2023 in addition to jobs associated with pipeline construction.10

Successful completion of TMMEP will put an additional 590,000 b/d of Canadian oil on the global market.

Delays in the construction of TMMEP cost Canadians $693 million every year.8

**TRANS MOUNTAIN (TMMEP) EXPANSION PROJECT**

<table>
<thead>
<tr>
<th>Year</th>
<th>Key Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>Application filed with NEB.</td>
</tr>
<tr>
<td>2015</td>
<td>NEB determined application complete.</td>
</tr>
<tr>
<td>2016</td>
<td>NEB recommends approval subject to 157 conditions.</td>
</tr>
<tr>
<td>2017</td>
<td>Final investment decision (FID) made. Successful IPO announced.</td>
</tr>
<tr>
<td>2018</td>
<td>Successful IPO announced.</td>
</tr>
<tr>
<td>2019</td>
<td>Federal government announces purchase of the Trans Mountain pipeline and expansion project for $4.5 billion.</td>
</tr>
<tr>
<td>2020+</td>
<td>Earliest estimate for in-service.</td>
</tr>
</tbody>
</table>

**TRANS MOUNTAIN EXPANSION**

- **COST:** C$7.4 billion (March 2017 estimate)
- **CAPACITY:** 890,000 b/d (300,000 b/d existing + 590,000 b/d additional)
- **LENGTH:** 1,183 kilometres (987 new + 193 reactivated + 2 x 3.6 km)
- **DIAMETER:** 36 inches
- **CONTRACTS:** 707,500 b/d (13 shippers: 15 and 20 year terms)
### 4.2.3 Keystone XL

The proposed 830,000 b/d TC Energy Keystone XL (KXL) pipeline will run from Hardisty, Alberta to Steele City, Nebraska. It can then connect to the existing Keystone system to transport Canadian crude to refineries on the U.S. Gulf Coast. The pipeline route passes through three U.S. states: Montana, South Dakota and Nebraska.

In November 2018, a federal district court in Montana ordered that TC Energy cease construction on the KXL project until the U.S. State Department completed a further environmental review. However, in March 2019 a new Presidential Permit was issued, which could render the Montana proceedings moot as this new permit does not reference or directly tie to any environmental review.

TC Energy has the primary state permits needed from South Dakota but is still awaiting some water use permits from the South Dakota Department of Environment and Natural Resources.

The Nebraska Supreme Court is expected to rule later in 2019 on KXL's proposed alternative route through the state.

**Successful completion of KXL will put an additional 830,000 b/d of Canadian oil on the global market.**
In 2014, Transport Canada, with the U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration, announced new rail tank car requirements including puncture resistance and thicker walls. Retrofits of existing tank cars must be completed by 2020, and all newly built cars must meet even more stringent standards. As a result, both retrofitted and new tank cars are in short supply. While CAPP supports stringent safety standards for tank cars, the switch to cars that meet safety standards will take time, further enforcing the need for pipelines.

The rail-loading capacity originating in Western Canada is 1.1 million b/d. However, ramping up rail capacity is not a comprehensive solution. Rail offers an alternative mode of transportation that industry will increasingly rely upon to transport crude oil as new pipeline projects continue to face challenges and delays. Industry data shows that approximately 233,000 b/d was transported by rail in 2018. The highest reported average volume moved in a month in 2018 was 354,000 b/d, compared to 156,000 b/d in 2017. The greatest number of rail cars moving crude in 2018 was 25,404 in November, compared to a previous historical peak of 17,371 in January 2014 (Figure 4.5).

Figure 4.5: Canadian Fuel Oil and Crude Petroleum Moved by Rail
Source: Statistics Canada, Table 23-10-0210-01

<table>
<thead>
<tr>
<th>Operator</th>
<th>Capacity (b/d)</th>
<th>Scheduled Start up</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta</td>
<td>712,500</td>
<td>Operating since 2015</td>
</tr>
<tr>
<td>Kinder Morgan/Imperial</td>
<td>Sherwood Park</td>
<td>210,000</td>
</tr>
<tr>
<td>Gibson/USD Group</td>
<td>Hardisty</td>
<td>225,000</td>
</tr>
<tr>
<td>Cenovus</td>
<td>Brooks</td>
<td>100,000</td>
</tr>
<tr>
<td>Keyera/Kinder Morgan</td>
<td>Edmonton</td>
<td>40,000</td>
</tr>
<tr>
<td>Altex</td>
<td>Lynton</td>
<td>27,000</td>
</tr>
<tr>
<td>Savage</td>
<td>Reno</td>
<td>25,000</td>
</tr>
<tr>
<td>Keyera/Enbridge</td>
<td>Cheecham</td>
<td>24,000</td>
</tr>
<tr>
<td>Gibson</td>
<td>Edmonton</td>
<td>42,500</td>
</tr>
<tr>
<td>Secure/Predator</td>
<td>High Prairie</td>
<td>19,000</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>335,000</td>
<td>Operating since 2016</td>
</tr>
<tr>
<td>Plains</td>
<td>Alberta</td>
<td>70,000</td>
</tr>
<tr>
<td>Altex</td>
<td>Lashburn</td>
<td>88,000</td>
</tr>
<tr>
<td>Crescent Point</td>
<td>Stoughton</td>
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</tr>
<tr>
<td>TORQ Transloading</td>
<td>Unity</td>
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<td>Altex</td>
<td>Unity</td>
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</tr>
<tr>
<td>TORQ Transloading</td>
<td>Lloydminster</td>
<td>24,200</td>
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<tr>
<td>TORQ Transloading</td>
<td>Bromhead</td>
<td>45,300</td>
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<tr>
<td>Secure/Predator</td>
<td>High Prairie</td>
<td>19,000</td>
</tr>
<tr>
<td>Total</td>
<td>1,108,000</td>
<td></td>
</tr>
</tbody>
</table>

Note: Facilities with less than 15,000 b/d are not shown. "Estimated capacities based on assumptions for operating hours, available car spots, type of crude oil transported, and contracts in place (if known).
Numerous large oil companies have exited Canada after continual pipeline delays and increasingly inefficient and duplicative regulations. The U.S. administration has aggressively streamlined regulations and re-adjusted tax rates. In sharp contrast to the experience in Western Canada, the growth in production in the U.S. has been facilitated by a significant increase in pipeline capacity with a number of pipeline projects recently completed and several more projects currently under construction to move crude oil to Gulf Coast refiners. In recent years the production of crude oil in the Permian basin has increased from less than one million b/d in 2010 to more than 4.1 million b/d in 2019 (Table 4.4 and Figure 4.7). In addition to pipelines currently under construction, a number of other proposals are in early stages of development.

Table 4.4 Recently Constructed and Under Construction Crude Oil Pipelines Exiting the Permian Basin

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Owner</th>
<th>Capacity</th>
<th>Status</th>
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</thead>
<tbody>
<tr>
<td>Permian Longview &amp; Louisiana Extension</td>
<td>Sunoco</td>
<td>100,000 bpd</td>
<td>Operational since 2016</td>
</tr>
<tr>
<td>Permian Express II</td>
<td>Sunoco</td>
<td>200,000 bpd</td>
<td>Operational since 2015</td>
</tr>
<tr>
<td>BridgeTex Expansion</td>
<td>Magellan Midstream</td>
<td>400,000 bpd</td>
<td>Operational expansion since 2017</td>
</tr>
<tr>
<td>Midland to Study</td>
<td>Enterprise Product Partners</td>
<td>575,000 bpd</td>
<td>Operational since 2018</td>
</tr>
<tr>
<td>Cactus Pipeline</td>
<td>Plains All American</td>
<td>300,000 bpd</td>
<td>Operational since 2015</td>
</tr>
<tr>
<td>Gray Oak</td>
<td>Phillips 66</td>
<td>800,000 bpd</td>
<td>Under Construction-in-service 4Q19</td>
</tr>
<tr>
<td>Cactus II</td>
<td>Plains All American</td>
<td>670,000 bpd</td>
<td>Under Construction-in-service 3Q19</td>
</tr>
<tr>
<td>Epic Crude Pipeline</td>
<td>Epic Midstream Holdings</td>
<td>900,000 bpd</td>
<td>Under Construction-in-service 4219</td>
</tr>
<tr>
<td>Midland to Sealy</td>
<td>Enterprise Product Partners</td>
<td>575,000 bpd</td>
<td>Operational since 2015</td>
</tr>
<tr>
<td>BridgeTex Expansion</td>
<td>Magellan Midstream</td>
<td>400,000 bpd</td>
<td>Operational expansion since 2017</td>
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<td>Permian Express II</td>
<td>Sunoco</td>
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<td>Permian Longview &amp; Louisiana Extension</td>
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<tr>
<td>Permian Express II</td>
<td>Sunoco</td>
<td>200,000 bpd</td>
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<td>BridgeTex Expansion</td>
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<td>Enterprise Product Partners</td>
<td>575,000 bpd</td>
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<tr>
<td>Cactus Pipeline</td>
<td>Plains All American</td>
<td>300,000 bpd</td>
<td>Operational since 2015</td>
</tr>
<tr>
<td>Gray Oak</td>
<td>Phillips 66</td>
<td>800,000 bpd</td>
<td>Under Construction-in-service 4Q19</td>
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<tr>
<td>Cactus II</td>
<td>Plains All American</td>
<td>670,000 bpd</td>
<td>Under Construction-in-service 3Q19</td>
</tr>
<tr>
<td>Epic Crude Pipeline</td>
<td>Epic Midstream Holdings</td>
<td>900,000 bpd</td>
<td>Under Construction-in-service 4219</td>
</tr>
<tr>
<td>TOTAL</td>
<td></td>
<td>3,945,000 bpd</td>
<td></td>
</tr>
</tbody>
</table>

The anticipated Trans Mountain decision in June 2019 has the potential to alleviate some of the market access constraints the industry faces and allow Canadians to receive the best value for resources. Global demand for oil, including heavy oil such as WCS, is growing – especially in India, China and Southeast Asia. Canadian producers have an opportunity to export oil to emerging global markets but there is not enough pipeline capacity to allow producers to capitalize on this growing demand. By 2035, the supply of crude oil is expected to increase by 1.7 million b/d and even this constrained outlook of supply growth is contingent on Canada significantly increasing its egress capacity from the WCSB.
1. April MPR Report: The Bank expects that the level of investment in the oil and gas sector in 2019 will be about 20 per cent lower than its 2017 plateau. This contraction follows the steep decline of roughly 50 per cent that occurred between 2014 and 2016. The Bank’s projections for production and exports of Canadian oil are anchored by transportation capacity rather than by an assumption about the price of Western Canadian Select.


10. CAPP estimates based on Prism Economics analysis of the oil and natural gas industry’s economic impacts according to Statistics Canada’s Input/Output tables.


12. Ibid


14. Figure 4.8 Notes. Capacity shown can be reduced by any extraordinary and temporary operating and physical constraints. 1. Enbridge capacity adjusted by operational downtime and capacity for RPP and U.S. Bakken crude oil. 2. Keystone: adjustment to 99% of nameplate capacity for maintenance downtime. 3. Express: contract capacity only due to downstream Platte pipeline constraints. 4. Trans Mountain: RPP capacity requirements subtracted from nameplate capacity. 5. Rangeland and Milk River: throughput estimated at 107,000 b/d, which is the maximum realized annual crude oil throughput since 2010. 6. Western Canadian refineries: approximate refinery intake in AB (incl. Sturgeon refinery from 2018+) and SK but excludes BC (85% of 682,000 b/d).
## APPENDIX A.1

### CRUDE OIL FORECAST, MARKETS AND TRANSPORTATION

**EASTERN CANADA 2010 - 2035**

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<thead>
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<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Atlantic provinces (including Pentanes &amp; Condensate)*</td>
<td>283</td>
<td>272</td>
<td>201</td>
<td>231</td>
<td>197</td>
<td>212</td>
<td>223</td>
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<td>148</td>
<td>130</td>
<td>115</td>
<td>102</td>
<td>90</td>
</tr>
<tr>
<td><strong>Eastern Canada</strong></td>
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<td>274</td>
<td>202</td>
<td>232</td>
<td>220</td>
<td>176</td>
<td>213</td>
<td>224</td>
<td>233</td>
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<td>293</td>
<td>236</td>
<td>185</td>
<td>149</td>
<td>130</td>
<td>115</td>
<td>102</td>
</tr>
</tbody>
</table>

### WESTERN CANADA

#### Conventional Light & Medium

- **Alberta**
- **British Columbia**
- **Saskatchewan**
- **Manitoba**
- **North West Territories**

#### Heavy

- **Alberta Conventional Heavy**
- **Saskatchewan Conventional Heavy**
- **Western Canada Conventional Heavy**

### WESTERN CANADA (incl. Pentanes/Condensate)

- **Western Canada Conventional**

### OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)

#### Oil Sands Mining

- **Oil Sands In Situ**

### TOTAL WESTERN CANADA CRUDE OIL PRODUCTION

- **Total Pentanes/Condensate**

### TOTAL EASTERN CANADA CRUDE OIL PRODUCTION

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</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Western Canada</strong></td>
<td>2,554</td>
<td>2,741</td>
<td>3,042</td>
<td>3,239</td>
<td>3,521</td>
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<td>3,641</td>
<td>3,963</td>
<td>4,356</td>
<td>4,755</td>
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<td>6,057</td>
<td>6,133</td>
<td>6,192</td>
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</tr>
<tr>
<td><strong>Total Eastern Canada</strong></td>
<td>284</td>
<td>274</td>
<td>202</td>
<td>232</td>
<td>220</td>
<td>176</td>
<td>213</td>
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<td>185</td>
<td>149</td>
<td>130</td>
<td>115</td>
<td>102</td>
</tr>
</tbody>
</table>

### TOTAL CANADIAN CRUDE OIL PRODUCTION

**Notes:**

1. Atlantic Canada production includes Newfoundland & Labrador production and minor volumes from Nova Scotia. Condensate/pentanes from Nova Scotia are also included.
2. CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.
3. CAPP has revised from June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.
4. Pentanes/Condensate production reported does not include pentanes that are part of the NGL stream that is shipped to Ontario. Only produced volumes that are available for diluent purposes are reported here.
5. Raw bitumen numbers are provided at the bottom of the table and do not reflect upgrading. The oil sands production numbers at the top of the table (as historically published) are a combination of upgraded crude oil and bitumen, therefore, incorporate yield losses from integrated upgrader projects. Production from off-site upgrading projects are included in the production numbers as bitumen.

### OIL SANDS RAW BITUMEN

- **Total Western Canada**
- **Total Eastern Canada**

### TOTAL OIL SANDS (BITUMEN & UPGRADED CRUDE OIL)

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</thead>
<tbody>
<tr>
<td><strong>Total Western Canada</strong></td>
<td>1,616</td>
<td>1,745</td>
<td>1,926</td>
<td>2,085</td>
<td>2,305</td>
<td>2,527</td>
<td>2,538</td>
<td>2,823</td>
<td>3,055</td>
<td>3,153</td>
<td>3,332</td>
<td>3,422</td>
<td>3,524</td>
<td>3,598</td>
<td>3,650</td>
<td>3,719</td>
<td>3,784</td>
<td>3,854</td>
<td>3,925</td>
<td>4,006</td>
<td>4,088</td>
<td>4,170</td>
<td>4,242</td>
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<tr>
<td><strong>Total Eastern Canada</strong></td>
<td>2,839</td>
<td>3,015</td>
<td>3,244</td>
<td>3,472</td>
<td>3,742</td>
<td>3,853</td>
<td>3,854</td>
<td>4,167</td>
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<td>5,456</td>
<td>5,557</td>
<td>5,644</td>
<td>5,763</td>
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<td>5,970</td>
<td>6,074</td>
<td>6,192</td>
<td>6,312</td>
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</table>

### TOTAL OIL SANDS PRODUCTION

- **Oilsands Mining**
- **Oilsands In Situ**

### OIL SANDS RAW BITUMEN

- **Total Western Canada**
- **Total Eastern Canada**

### TOTAL OIL SANDS PRODUCTION

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<tbody>
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<td>1,745</td>
<td>1,926</td>
<td>2,085</td>
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<td>2,527</td>
<td>2,538</td>
<td>2,823</td>
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<td>3,153</td>
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<tr>
<td><strong>Total Eastern Canada</strong></td>
<td>2,839</td>
<td>3,015</td>
<td>3,244</td>
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<td>5,970</td>
<td>6,074</td>
<td>6,192</td>
<td>6,312</td>
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</table>

### Notes:

1. Atlantic Canada production includes Newfoundland & Labrador production and minor volumes from Nova Scotia. Condensate/pentanes from Nova Scotia are also included.
2. CAPP allocates Saskatchewan Area III Medium crude as heavy crude. Also 17% of Area IV is > 900 kg/m³.
3. CAPP has revised from June 2007 report historical light/heavy ratio for Saskatchewan starting in 2005.
4. Pentanes/Condensate production reported does not include pentanes that are part of the NGL stream that is shipped to Ontario. Only produced volumes that are available for diluent purposes are reported here.
### APPENDIX A.2

#### CAPP Western Canadian Crude Oil Supply Forecast 2019 - 2035

Blended Supply to Trunk Pipelines and Markets

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<tbody>
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<td><strong>CONVENTIONAL</strong> Light and Medium</td>
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<td>603</td>
<td>701</td>
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<td>794</td>
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<tr>
<td><strong>Net Heavy to Market</strong></td>
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<tr>
<td><strong>OIL SANDS</strong></td>
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<td><strong>920</strong></td>
<td><strong>1,038</strong></td>
<td><strong>1,099</strong></td>
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<td><strong>901</strong></td>
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<td><strong>901</strong></td>
<td><strong>893</strong></td>
<td><strong>886</strong></td>
<td><strong>877</strong></td>
<td><strong>873</strong></td>
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<tr>
<td>Total Light Supply</td>
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<td>2,184</td>
<td>2,352</td>
<td>2,672</td>
<td>2,963</td>
<td>3,009</td>
<td>3,276</td>
<td>3,698</td>
<td>3,850</td>
<td>4,092</td>
<td>4,216</td>
<td>4,356</td>
<td>4,412</td>
<td>4,477</td>
<td>4,555</td>
<td>4,660</td>
<td>4,747</td>
<td>4,839</td>
<td>4,877</td>
<td>4,966</td>
<td>5,056</td>
<td>5,137</td>
<td>5,262</td>
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<tr>
<td>Total Heavy Supply</td>
<td>2,668</td>
<td>2,900</td>
<td>3,222</td>
<td>3,451</td>
<td>3,800</td>
<td>3,982</td>
<td>3,910</td>
<td>4,204</td>
<td>4,657</td>
<td>4,802</td>
<td>5,004</td>
<td>5,226</td>
<td>5,297</td>
<td>5,384</td>
<td>5,472</td>
<td>5,581</td>
<td>5,666</td>
<td>5,703</td>
<td>5,783</td>
<td>5,867</td>
<td>5,949</td>
<td>6,023</td>
<td>6,139</td>
<td>6,254</td>
<td></td>
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<tr>
<td><strong>WESTERN CANADA CRUDE OIL SUPPLY</strong></td>
<td>4,454</td>
<td>4,880</td>
<td>5,235</td>
<td>5,320</td>
<td>5,384</td>
<td>5,317</td>
<td>5,177</td>
<td>5,188</td>
<td>5,217</td>
<td>5,295</td>
<td>5,387</td>
<td>5,493</td>
<td>5,623</td>
<td>5,730</td>
<td></td>
<td></td>
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</tbody>
</table>

**Notes:**
1. Includes upgraded conventional
2. Includes: a) imported condensate b) manufactured diluent from upgraders and c) upgraded heavy volumes coming from upgraders

#### Acronyms, Abbreviations, Units and Conversion Factors

**Acronyms**
- API: American Petroleum Institute
- AER: Alberta Energy Regulator
- CAPP: Canadian Association of Petroleum Producers
- EIA: Energy Information Administration
- FERC: Federal Energy Regulatory Commission
- IEA: International Energy Agency
- NEB: National Energy Board
- PADD: Petroleum Administration for Defense District
- RPP: refined petroleum products
- U.S.: United States

**Canadian Provincial Abbreviations**
- AB: Alberta
- BC: British Columbia
- MB: Manitoba
- NB: New Brunswick
- NL: Newfoundland and Labrador
- NT: Northwest Territories
- ON: Ontario
- QC: Quebec
- SK: Saskatchewan

**U.S. State Abbreviations**
- AL: Alabama
- AK: Alaska
- AZ: Arizona
- AR: Arkansas
- CA: California
- CO: Colorado
- CT: Connecticut
- DE: Delaware
- FL: Florida
- GA: Georgia
- ID: Idaho
- IL: Illinois
- IN: Indiana
- IA: Iowa
- KS: Kansas
- KY: Kentucky
- LA: Louisiana
- ME: Maine
- MD: Maryland
- MA: Massachusetts
- MI: Michigan
- MN: Minnesota
- MS: Mississippi
- MO: Missouri
- MT: Montana
- NE: Nebraska
- NV: Nevada
- NH: New Hampshire
- NJ: New Jersey
- NM: New Mexico
- NY: New York
- NC: North Carolina
- ND: North Dakota
- OH: Ohio
- OK: Oklahoma
- OR: Oregon
- PA: Pennsylvania
- TX: Texas
- TN: Tennessee
- UT: Utah
- VT: Vermont
- VA: Virginia
- WI: Wisconsin
- WV: West Virginia
- WA: Washington
- WY: Wyoming

**Units**
- b/d: barrels per day

**Conversion Factor**
- 1 cubic metre = 6.293 barrels (oil)
The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP’s member companies produce about 80 per cent of Canada’s natural gas and crude oil. CAPP’s associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP’s members and associate members are an important part of a national industry with revenues from oil and natural gas production of about $101 billion a year.