Husky Energy

Energy Driven

Annual Report **2018**

Corporate Profile

Husky Energy is an integrated energy company based in Calgary, Alberta and its common shares are publicly traded on the Toronto Stock Exchange under the symbol HSE. The Company operates in Canada, the United States and the Asia Pacific region with Upstream and Downstream business segments.

Husky has two main areas of focus:

The **Integrated Corridor** includes the production of thermal bitumen, natural gas and associated liquids in Western Canada, the Lloydminster upgrading and refining complex, a 35 percent working interest and operatorship of Husky Midstream Limited Partnership, and the Lima, Superior and Toledo refineries in the U.S. Midwest.

The **Offshore** business includes operations and exploration in the Asia Pacific region, primarily offshore China and Indonesia, and in the Atlantic region offshore Newfoundland and Labrador.

Results

Financial[1]

Year ended December 31	2018	2017
(millions of dollars except where indicated)		
Gross revenues and Marketing and other	22,587	18,946
Revenues, net of royalties	22,252	18,583
Cash flow – operating activities	4,134	3,704
Funds from operations[2]	4,004	3,306
Per common share – basic *($/share)*	3.98	3.29
Free cash flow[2]	426	1,086
Net earnings	1,457	786
Per common share – basic *($/share)*	1.41	0.75
Net debt[3]	2,881	2,927
Dividends per common share – ordinary *(dollars)*[4]	0.450	0.075
Capital expenditures[5][6]	3,578	2,220

Operations

	2018	2017
Daily production, before royalties		
Total equivalent production *(mboe/day)*	299.2	322.9
Crude oil & natural gas liquids *(mbbls/day)*	214.7	233.0
Natural gas *(mmcf/day)*	507.0	539.1
Total proved reserves, before royalties *(mmboe)*[7]	1,471	1,301
U.S. refinery net throughput *(mbbls/day)*[8]	233.9	254.3
Canadian refining and upgrading throughput *(mbbls/day)*	113.4	106.5

(1) Results are reported in accordance with IFRS, as issued by the IASB, except where indicated.
(2) Non-GAAP measures. Please refer to "Advisories".
(3) Net debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt, less cash and cash equivalents. Please refer to "Advisories".
(4) Declared for the three-month period ended Dec. 31, 2018; payable on April 1, 2019.
(5) Excludes acquisition of the Superior Refinery in Q4 2017; excludes asset retirement obligations and capitalized interest.
(6) Capitalized expenditures exclude amounts related to the Husky-CNOOC Madura and Husky Midstream Limited Partnership joint ventures, which are accounted for under the equity method for financial statement purposes.
(7) Total proved reserves based on forecasted prices in accordance with National Instrument 51-101.
(8) Husky owns 50% of the Toledo Refinery.

Report to Shareholders

Husky's integrated business model served us well in 2018. The Company achieved global pricing for the majority of its products, reinforcing its ability to generate free cash flow, return cash to shareholders and maintain the strength of the balance sheet.

Husky progressed a deep portfolio of higher margin projects as it continued to execute its five-year plan.

Through a commitment to capital discipline and creating added value for our shareholders, net debt at the end of 2018 was approximately $2.9 billion, well below the target of less than two times funds from operations.

Funds from operations and net earnings were up substantially over the previous year.

The Integrated Corridor and our high-netback Offshore businesses, which include Asia and the Atlantic region, are positioned to increase the stability and predictability of funds from operations and free cash flow through all market cycles.

In 2018, Husky's financial performance contributed to an increased quarterly cash dividend, as well as the advancement of a series of planned thermal bitumen projects at Lloydminster in Western Canada, and the West White Rose Project offshore Newfoundland and Labrador.

In response to the incident at the Superior Refinery and the offshore oil spill in the Atlantic region, an extensive third-party review was conducted of the Company's safety and operational integrity, and further improvements put into place.

Several operational highlights were achieved in 2018:

Along the Integrated Corridor, first production began six months ahead of schedule at the 10,000 barrel-per-day Rush Lake 2 thermal project in Lloydminster. Five additional thermal projects are being advanced, representing a combined design capacity of 50,000 barrels per day (bbls/day).

The Tucker Thermal Project reached its design capacity target of 30,000 bbls/day in the fourth quarter, while the Sunrise Energy Project surpassed its 60,000 bbls/day design capacity near year end.

In Western Canada, a more centralized and cost-effective drilling program has lowered operating and capital costs, resulting in a more competitive business with the flexibility to pivot between liquids-rich or dry gas production to realize the best pricing.

In a year of record-high location differentials for Canadian heavy oil and bitumen, the benefits of tight physical integration came into clear focus. The Company's significant upgrading and refining capacity, long-term export pipeline access, storage and logistical assets captured global pricing for the vast majority of production.

This resiliency is expected to continue in 2019, and beyond. Despite Alberta government-mandated oil production cuts that discriminate unfairly against integrated producers like Husky, our Company remains focused on capturing maximum value through all commodity cycles, including increasing its investments outside of Alberta.

In Asia, the Company's long-term contracts in the fast-growing energy market provided for strong netbacks, contributing to more stable and predictable generation of free cash flow.

In the Atlantic region, the West White Rose Project is under construction and progressing towards a 2022 startup. Both Offshore regions marked new discoveries in 2018 that are being evaluated for potential commercial development.

Looking ahead, Husky will continue to execute against its five-year plan while improving safety, delivering enhanced value to shareholders, and strengthening relationships in the communities where it operates.

Thank you to all of our shareholders for your ongoing support.

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

The crude oil flexibility project at the Lima Refinery will increase heavy oil processing capacity to 40,000 bbls/day by the end of 2019.

Message from the CEO

In 2018, Husky marked its 80th year of responsibly producing the energy the world needs, an important milestone in an enduring legacy.

Over the past eight decades, Husky has demonstrated its ongoing commitment to delivering value for our shareholders.

This has included enhancing the asset portfolio over time, exercising capital discipline by maintaining a strong balance sheet through business cycles, investing in a deep organic portfolio of higher margin projects that can further improve our earnings break-even point, increasing free cash flow and returning cash to shareholders via a strong dividend.

At the same time, we have worked to step up our performance in a world with higher environmental, regulatory and social expectations. This includes taking steps to improve our safety performance, ensuring reliable operations and reducing our environmental footprint.

We experienced some challenging operational incidents in 2018 at our newly acquired Superior Refinery and offshore Newfoundland and Labrador. As a result, we have put into place additional proactive steps to improve our safety processes and response protocols. Compensation for all Husky employees is now more closely linked to safety performance, and to provide clear leadership and oversight, I created a new executive position in charge of process and occupational safety reporting directly to me. Husky is working with top industry experts to implement the best safety and compliance practices throughout our organization.

We made good progress in 2018 advancing our five-year plan. We realized the highest funds from operations in four years, driven by strong production and throughputs in our Integrated Corridor and Offshore businesses, including setting new production milestones at Liwan, Sunrise and Tucker.

Rob Peabody
President & Chief Executive Officer

Husky's physically integrated Downstream processing and committed export pipeline capacity continued to capture value and reduced our exposure to record Canadian heavy oil price differentials in 2018.

The fundamental structural transformation of our Western Canada resource play business over the past few years has resulted in steadily declining operating costs, faster drilling times and better well performance. Altogether, Husky has sold more than 52,000 barrels of oil equivalent per day in higher-cost legacy assets. With respect to older, inactive wells facing abandonment, we take a proactive approach to asset retirement that addresses the reclamation and remediation of entire sites and related infrastructure in a cost-effective manner.

In 2018, we also made significant progress on growth, advancing a series of Lloyd thermal developments, the Liuhua 29-1 field at Liwan and the West White Rose Project.

This type of portfolio optimization will continue in 2019 with the strategic review and potential sale of our Canadian retail and commercial fuels business and the Prince George Refinery.

We are also pioneering, assessing and adopting the latest technologies to improve safety, increase capital efficiency, lower our operating costs and improve our environmental performance. These initiatives include using artificial intelligence (AI) to optimize steam-oil ratios in SAGD production and applying machine-learning technology to augment weather and iceberg drift predictions, with the aim of improving safety and the efficiency of offshore operations.

Finally, in September 2018, we announced an offer to acquire all the outstanding shares of MEG Energy. As a result of insufficient MEG Board and shareholder support, as well as several negative developments in the business and economic environment, the offer expired and was not extended.

As we move forward into 2019, our strategy is clear. While the macro market environment remains volatile and the geo-political landscape uncertain, we continue to have one of the strongest balance sheets in the industry. As we focus on improving safety and reliability, reducing emissions, and increasing our funds from operations and free cash flow, we will remain resilient to the downside while preserving the upside.

Rob Peabody

CEO Rob Peabody takes part in a safety briefing at the Moose Mountain facility. Process and occupational safety is a priority across all Husky operations.

2018 Highlights

Overall

- Average production of 299,200 boe/day
- Proved reserves replacement ratio of 260 percent, excluding economic factors (255 percent including economic factors); proved reserves life index of 13.5 years
- Cash flow – operating activities of $4.1 billion
- Funds from operations of $4.0 billion
- Free cash flow before dividends of $426 million
- $0.450 per common share dividend declared
- Capital spending of $3.6 billion
- Net debt of less than one times 2018 funds from operations, ending the year at $2.9 billion
- Upstream average operating cost of $14 per barrel

Integrated Corridor

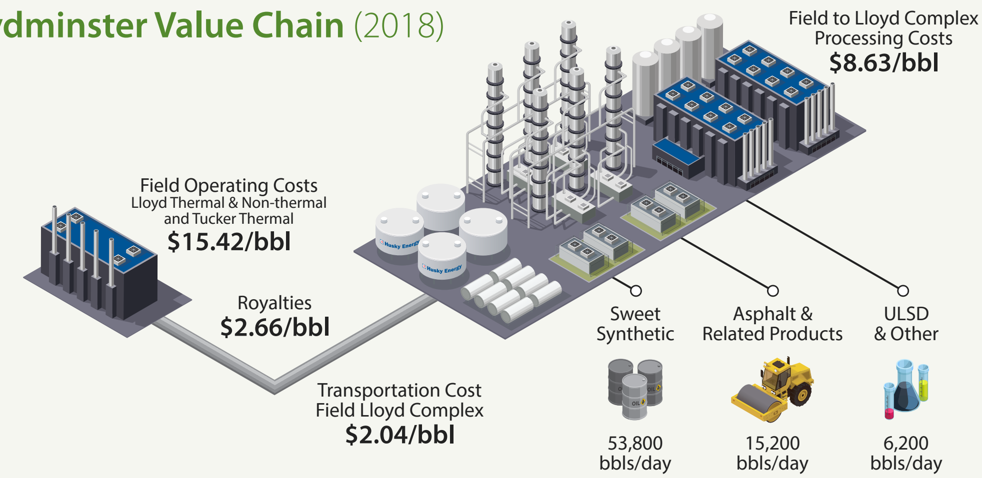
- Annual average Upstream production of 230,900 boe/day
- Upstream average operating netback of $11.92 per barrel
- Startup of Rush Lake 2 Lloyd thermal project with design production target reached ahead of schedule
- Sanctioned new 10,000 bbls/day Lloyd thermal project at Spruce Lake East
- The Sunrise Energy Project and Tucker Thermal Project reached production design capacity
- Successful resource play drilling program in Western Canada; resource play operating costs of $6.78 per boe in 2018 compared to $8.40 per boe in 2013; overall Western Canada operating costs of $12.43 per boe compared to $17.04 per boe five years ago
- Upgrading and refining average throughput of 347,300 bbls/day
- Downstream upgrading and refining margin of $20.09 per barrel
- Record throughput of 75,600 bbls/day at the Lloydminster Upgrader; EBITDA of $620 million, up 147 percent over 2017
- Accelerated asset retirement program resulted in the full abandonment of 1,058 wells and nearly 900 kilometres of pipeline; 320 reclamation certificates received

Offshore

- Annual average production of 68,300 boe/day, including record production at the Liwan Gas Project offshore China and the liquids-rich BD Project in Indonesia
- Average operating netbacks of $64.67 per boe
- Commenced construction on the Liuhua 29-1 field at at Liwan; first production expected around the end of 2020
- Signed Production Sharing Contracts for two exploration blocks offshore China in the Beibu Gulf
- Progressed construction of the West White Rose Project offshore Newfoundland
- Agreed to fiscal terms for the Bay du Nord project offshore Newfoundland
- Successful exploration wells drilled in the Asia Pacific and Atlantic regions

Husky's Integrated Corridor is purpose-built to capture margins from the reservoir through to the refinery rack. Heavy oil production is upgraded and refined at the Lloydminster Refining Complex, and bitumen from the Sunrise Energy Project is processed through the Company's Midwest U.S. refineries.

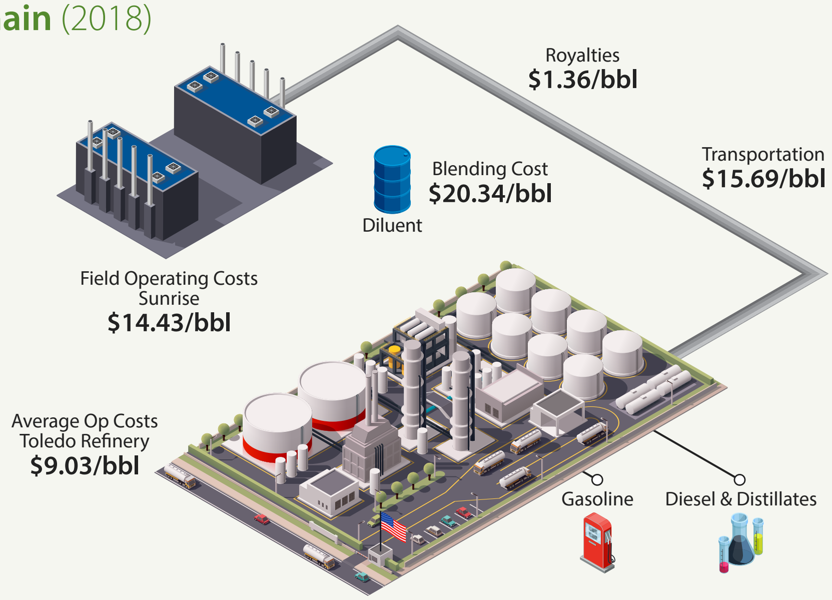
Lloydminster Value Chain (2018)



Lloydminster Value Chain Operating Netback ($ per barrel) **$47**

$75.83/bbl
Average Realized Price

Sunrise Value Chain (2018)



Sunrise Value Chain Operating Netback ($ per barrel) **$35**

$96.45/bbl
Average Refined Product Realization

2018 Business

Production

Average annual production was approximately 300,000 boe/day.

Thermal bitumen production from the Sunrise Energy Project, the Tucker Thermal Project and Lloyd heavy oil thermal projects averaged 133,000 bbls/day in the fourth quarter of 2018, a 10 percent increase over the previous year, reflecting reliable and efficient operational performance and the start-up of the 10,000 bbls/day Rush Lake 2 thermal project in October.

Offshore, annual sales at the Liwan Gas Project averaged 377 million cubic feet per day of gas and 17,100 bbls/day of associated liquids (185 mmcf/day and 8,400 bbls/day Husky working interest.) Record quarterly production of 403 mmcf/day was achieved in the fourth quarter, with associated liquids averaging 19,200 bbls/day (197 mmcf/day and 9,300 bbls/day Husky working interest.)

In Indonesia, the BD Project in the Madura Strait achieved and surpassed its gas sales targets of 100 mmcf/day, with higher than anticipated liquids production. Gas sales in the fourth quarter averaged 91 mmcf/day, with liquids production of 7,700 bbls/day (38 mmcf/day and 2,800 bbls/day Husky working interest.) Annual sales at BD averaged 78 mmcf/day of gas and 6,200 bbls/day of liquids (31 mmcf/day and 2,500 bbls/day Husky working interest.)

The Rush Lake 2 thermal project ramped up to full design production capacity in 2018.

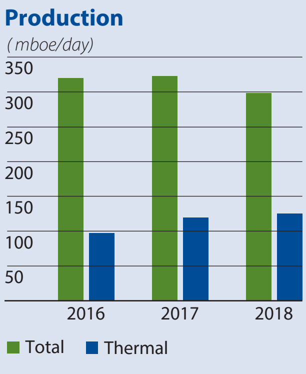
Funds from Operations and Free Cash Flow

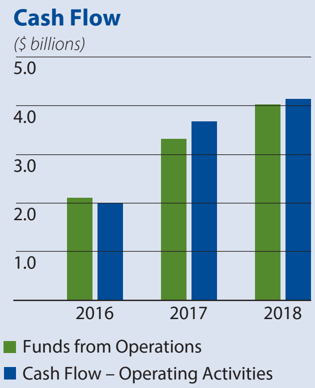
Funds from operations was $4.0 billion, up more than 20 percent over the previous year. This takes into account a number of factors, including strong gas demand in Asia and the Company's ability to capitalize on location differentials to capture full value through its tight physical integration.

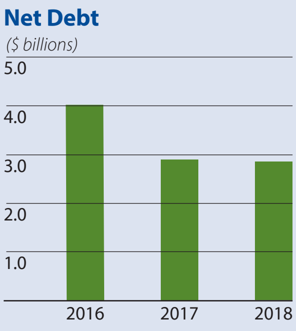
Free cash flow before dividends was $426 million. Cash flow provided by operating activities, which includes changes in non-cash working capital, was $4.1 billion in 2018 compared to $3.7 billion in 2017.

Debt Reduction

Net debt was approximately $2.9 billion, including more than $2.8 billion in cash, representing less than one times 2018 funds from operations, with $4.3 billion in undrawn credit facilities. The Company continued to maintain investment-grade credit ratings.







Earnings

Net earnings were $1.5 billion, up 85 percent over 2017, reflecting robust crude oil prices in the first three quarters of 2018 and strong Asia Pacific production.

Capital Expenditures

Capital spending was approximately $3.6 billion, compared to $2.2 billion in 2017.

Spending was largely directed towards higher margin production. This included advancing a series of Lloyd thermal projects in Saskatchewan, construction of the West White Rose Project, accelerating a planned drilling program for resource plays in Western Canada, and increasing Husky's working interest in the Liuhua 29-1 field at the Liwan Gas Project.

Reserves Replacement

The proved reserves life index was 13.5 years, an increase from 11 years in 2017.

Total proved reserves before royalties at the end of 2018 were 1.5 billion boe. Probable reserves were 1.1 billion boe.

The 2018 proved reserves replacement ratio was 260 percent, excluding economic factors (255 percent including economic factors).

The average five-year proved reserves replacement ratio was 144 percent, excluding economic factors (135 percent including economic factors).

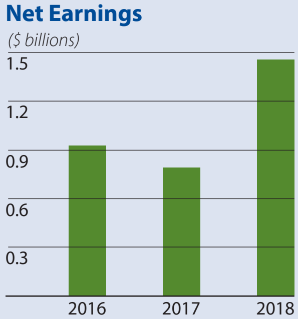
The Sunrise Energy Project reached a record peak daily rate of 62,600 bbls/day (31,300 bbls/day Husky working interest).

These take into account acquisitions and the disposition in Western Canada of 62 million boe of proved reserves in 2017 and 90 million boe of proved reserves in 2016.

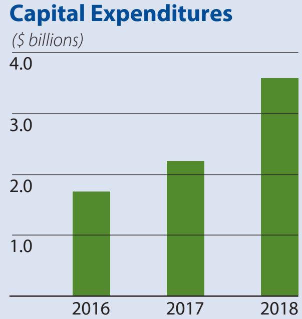
The five-year annual average proved reserves replacement ratio continues to exceed the target of more than 130 percent.

Proved reserves additions and revisions of 279 million boe, including economic factors, take into account additions related to two new sanctioned Lloyd thermal bitumen projects and improved performance in the existing projects, the booking of proved reserves for the Liuhua 29-1 project, and future development opportunities added at Sunrise, Lloyd thermal bitumen projects, Ansell, Kakwa, Wembley and other fields, offset by economic factors.

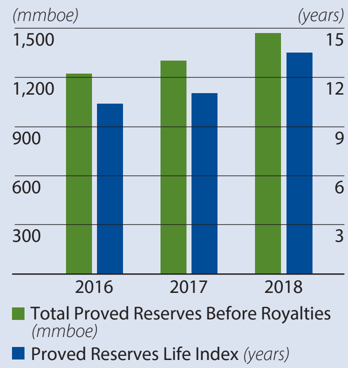
Net Earnings



Capital Expenditures



Reserves



Operations

Integrated Corridor

In 2018, Husky continued to capture value from its Integrated Corridor business, which is purpose-built to capture margins from the reservoir to the refinery rack.

Thermal Production

The combined thermal heavy oil and oil sands business produced more than 124,000 bbls/day of bitumen in 2018, as the Company developed and added to a large inventory of low cost, higher margin projects with lower sustaining capital requirements.

Record volumes were achieved at the Sunrise Energy Project and Tucker Thermal Project as they reached full design capacity in 2018. The 10,000 bbls/day Rush Lake 2 thermal project started up in the fourth quarter and surpassed its target design production capacity in five weeks.

Improved capital efficiency has led to more sustainable, lower-cost production.

Average per-barrel operating costs at Lloyd, Tucker and Sunrise were $11.43 in 2018, and plans are in place to deliver further operating cost reductions in future years.

An additional five Lloyd thermal projects are now being advanced, representing 50,000 bbls/day of production to be added through 2022. These long-life thermal projects are being phased to optimize capital efficiency and project execution.

- At Dee Valley, construction work is progressing with first oil planned in the fourth quarter of 2019.
- At Spruce Lake Central, the central plant is being assembled with first production expected in 2020.
- At Spruce Lake North, site clearing has been completed with first oil expected around the end of 2020.
- A new 10,000 bbls/day thermal project was sanctioned at Spruce Lake East, with first production targeted around the end of 2021.
- At Edam Central, regulatory approval has been received with production expected in 2022.

The Tucker Thermal Project ramped up to its 30,000 bbls/day design capacity in 2018.

Resource Plays

The repositioning of Husky's resource play business in Western Canada over the past few years has resulted in a more focused portfolio with lower operating costs, faster drilling times and improved well performance.

With leaner and repeatable operations at three core activity hubs at Edson, Grande Prairie and Rainbow Lake, operating costs for resource plays in Western Canada were $12.43 per boe in 2018, with approximately 5,000 boe/day of new production added over the year.

In the Ansell and Kakwa areas of the Wilrich formation, 21 wells were drilled and 24 wells were brought online.

In the Montney formation, seven wells were drilled and six completed in the Wembley and Karr areas. Wembley remains a focus of Husky's ongoing pivot towards greater liquids production.

Technology and data integration has played a significant role in improving well results at Ansell in Western Canada.

Downstream

Tight physical integration along the Integrated Corridor business helped mitigate persistent location differentials for the Company's heavy oil and bitumen production.

Downstream throughput averaged 347,000 bbls/day. At the Lima Refinery, maximum sustainable crude processing capacity was increased to up to 175,000 bbls/day as a result of improvements. A crude oil flexibility project currently under way at the refinery will increase heavy oil processing capacity from 10,000 bbls/day to 40,000 bbls/day when it is completed by the end of 2019.

The gross margin[1] at the Lloydminster Upgrader increased 80 percent year over year to $822 million, due in part to wider differentials.

The Lloydminster asphalt refinery delivered strong performance and reliability throughout the year, with the gross margin[1] rising 44 percent to $289 million.

Operations at the 45,000 bbls/day Superior Refinery were suspended in the second quarter of 2018 following a fire, and are expected to resume in 2020.

Throughout the year, Husky demonstrated the value of the flexibility in its system to source discounted feedstock from West Texas and Western Canada.

With ongoing export pipeline uncertainty, the Company remained well positioned with large refining and storage capacity in both Canada and the U.S., dedicated marketing and logistics assets, and secured pipeline access to the U.S., including 75,000 bbls/day capacity on the Keystone pipeline.

As part of its increasing focus on its core heavy oil operations and Downstream assets, Husky has announced plans to market and potentially sell its Canadian retail and commercial fuels business and the light oil Prince George Refinery.

(1) Gross margin is a non-GAAP measure and represents revenue less purchases of crude oil and product. Please refer to "Advisories".

Operations

Offshore

Asia Pacific

Husky is one of the few publicly-traded North American energy companies with significant exposure in the fast-growing energy markets in Asia. Long-term contracts with escalation factors deliver high netbacks and contribute to more stable and predictable cash flow.

Growing gas demand across the Asia Pacific region in 2018 resulted in record sales gas volumes averaging 377 mmcf/day from the two producing fields at the Liwan Gas Project, with associated liquids averaging 17,100 bbls/day (185 mmcf/day and 8,400 bbls/day Husky working interest).

Construction began on the third field at Liuhua 29-1. Seven wells are scheduled to be tied in to the main Liwan infrastructure in 2019, with production expected to begin around the end of 2020. Husky increased its working interest in Liuhua 29-1 to 75 percent from 49 percent, representing production of 45 mmcf/day of gas (Husky working interest) and 1,800 bbls/day of liquids (Husky working interest) once ramped up.

Offshore Indonesia, the BD Project achieved its total daily target of 100 mmcf/day (40 mmcf/day Husky working interest) with liquids production in the fourth quarter of about 7,700 bbls/day (2,800 bbls/day Husky working interest). The processed gas was sold into the East Java market at contracted rates for a realized price of $9.76 Cdn per thousand cubic feet in the fourth quarter, with liquids pricing of $96.83 Cdn per barrel.

Commercial development plans are being progressed following the drilling of a successful exploration well on Block 15/33 about 160 kilometres southeast of Hong Kong.

Production Sharing Contracts were signed for two shallow water blocks in the Beibu Gulf area of the South China Sea.

The BD Project offshore Indonesia continues to achieve its gas sales targets with strong liquids production.

Workers mark the completion of the shaft in caisson slip at the West White Rose Project construction site in Argentia, NL.

Atlantic

Building on more than 30 years of experience offshore Newfoundland and Labrador, Husky continued to advance a series of subsea development wells in the Jeanne d'Arc Basin in 2018 to mitigate anticipated reservoir declines until the West White Rose Project starts up in 2022.

Construction of the fixed wellhead drilling platform for West White Rose is proceeding at a purpose-built graving dock. The base slab was completed in 2018, and the central column was built to a height of 46 metres, with work on the topsides drilling unit and living quarters also under way.

The West White Rose Project is expected to reach peak production of 75,000 bbls/day (52,500 bbls/day Husky working interest) in the 2025 timeframe as development wells are drilled and brought online.

A new discovery was made at the White Rose A-24 exploration well located approximately 10 kilometres north of the *SeaRose* floating production, storage and offloading (FPSO) vessel, and is being evaluated for potential development. Husky has a 68.9 percent ownership interest in White Rose A-24.

Following an oil release from a subsea flowline connector near the South White Rose Extension in the fourth quarter, production at the *SeaRose* FPSO was suspended.

Husky worked closely with the Canada-Newfoundland & Labrador Offshore Petroleum Board (C-NLOPB) and operations resumed in early 2019 following remediation activities.

Process and Occupational Safety

Several process safety strategies were implemented in 2018 to reinforce the Company's commitment to process and occupational safety.

A new Senior Vice President of Safety & Operations Integrity was appointed, reporting directly to the CEO. In addition, an independent external team of experts is conducting an organization-wide assessment of safety processes and culture, working with Husky's leadership to deliver continuous improvement.

The Husky Operational Integrity Management System (HOIMS) was further strengthened in 2018 through an improved process to identify and review potential safety hazards at each facility and proactively develop controls to mitigate and manage associated risks.

At the same time, a revised mandatory nine Life-Saving Rules program was adopted across the business to equip workers with industry-standardized information and actions to protect themselves and their colleagues.

The Total Recordable Injury Rate (TRIR), which measures lost time, restricted work, medical aid incidents and fatalities, was reduced by eight percent to 0.57 in 2018.

Husky continues to work with the community, government agencies and its employees following the April 2018 fire at the Superior Refinery in Wisconsin and the November oil release in Atlantic Canada. In partnership with community leadership and government agencies, significant progress was made towards advancing a plan to bring the Superior Refinery back online. Operations are expected to resume in 2020. Husky received C-NLOPB approval to restart operations in Atlantic Canada in early 2019.

The SeaRose FPSO returned into service in early 2019.

Former U.S. nuclear submarine commander Bob Koonce is working with Husky to improve operational integrity and reduce risks through better safety and compliance practices.

Environment, Social and Governance

As Husky works to produce and deliver its essential energy products in a safe and responsible manner, it takes seriously its role as a responsible employer, neighbour, customer, taxpayer, innovator and environmental steward.

In 2018, the Environmental Social and Governance (ESG) management strategy was advanced and formalized in line with best practices to better inform and serve investors and stakeholders. The annual ESG report provides increased disclosure on areas that could pose material impacts to long-term sustainability and success, including water and land use, air emissions, asset integrity and reliability, and engagement with communities and Indigenous peoples.

Husky works to leave a positive legacy behind when operations cease, and is a recognized leader in asset retirement. It has pioneered a program-based approach to asset retirement referred to as Area-Based Closure, whereby all retirement activities are undertaken as a single program, greatly increasing the efficiency and effectiveness of the work. The Company takes a proactive approach to its asset retirement obligations and manages older, inactive projects and infrastructure through to closure in a responsible, sustainable manner. Asset retirement obligations and their status are tracked in Husky's Environmental Performance Reporting System.

Husky celebrated Pride Week and for the first time, participated in the Calgary Pride Parade.


Husky has pioneered an area-based asset retirement program, which has greatly increased efficiency and effectiveness.

New initiatives have been introduced to expand Indigenous economic inclusion, including bringing on more than 40 new strategic partnerships to provide goods and services and signing contracts worth about $30 million with Indigenous vendors. In Saskatchewan, Husky worked with First Nations to enhance economic and employment opportunities associated with its heavy oil thermal operations and to promote education and skills development. This included a program with Thunderchild First Nation that offered summer work terms to power engineering students, with the opportunity for full employment with Husky upon graduation.

Husky is committed to communities where it operates. In 2018, the Company supported various initiatives through corporate investments and in-kind contributions totalling more than $4 million. Employees volunteered over 12,000 hours in their local communities and raised more than $850,000 through an annual employee giving campaign.

Innovation and Technology

Husky takes a proactive approach to innovation and technology to improve safety, lower emissions, increase capital efficiency, reduce costs, and enhance revenue.

In 2018, the Innovation Gateway group was created to identify and validate the application of emerging technological developments in areas such as artificial intelligence. The group is advancing several initiatives, including technologies to improve reservoir screening for well interventions, reduce seismic processing and interpretation timeframes, automate clerical and back office functions and the prediction of potential equipment failures to enhance reliability and reduce costs.

Some examples: At Rainbow Lake, a pilot program has been installed to autonomously optimize wells to improve production and asset efficiency as well as reduce the frequency of site visits.

In the heavy oil business segment, a pilot machine-learning program was launched to optimize steam-oil ratios. The program aims to optimize thermal field operations to help develop a predictive model to standardize future responses. Full implementation of the project is planned in the 2019-2020 timeframe across the Company's thermal operations.

The Husky Diluent Reduction (HDR) initiative has the potential to increase the quality and value of Sunrise bitumen, reduce the amount of diluent required for blending and increase the effective capacity of the Company's pipelines.

New technological developments include improved reservoir screening and a pilot machine-learning program to optimize steam-oil ratios.

The Husky Diluent Reduction initiative continued to be advanced, with a 500-barrel-per-day pilot plant currently operating to reduce the amount of diluent required at Sunrise.

Husky is also investing in artificial intelligence and machine-learning technology to augment iceberg drift models and weather forecasting, including improved wave height prediction. Improved forecasting will enhance safety and optimize the utilization of offshore resources such as people, vessels and aircraft.

In addition, a new fibre-optic technology was installed for leak detection on pipelines. The system is able to sense and measure acoustics, temperature and vibration, assessing the pipeline's condition in real time to identify proactively any issues and provide a precise GPS location.

Management's Discussion and Analysis

February 25, 2019

Contents

1.0 Financial Summary

Selected Annual Information *($ millions, except where indicated)*	2018	2017	2016
Gross revenues and Marketing and other	**22,587**	18,946	13,224
Net earnings (loss) by business segment			
Upstream	**790**	260	1,091
Downstream	**1,000**	448	342
Corporate	**(333)**	78	(511)
Net earnings	**1,457**	786	922
Net earnings per share – basic	**1.41**	0.75	0.88
Net earnings per share – diluted	**1.40**	0.75	0.88
Cash flow – operating activities	**4,134**	3,704	1,971
Funds from operations(1)	**4,004**	3,306	2,198
Ordinary dividends per common share	**0.450**	0.075	—
Dividends per cumulative redeemable preferred share, series 1	**0.60**	0.60	0.73
Dividends per cumulative redeemable preferred share, series 2	**0.74**	0.57	0.42
Dividends per cumulative redeemable preferred share, series 3	**1.13**	1.13	1.13
Dividends per cumulative redeemable preferred share, series 5	**1.13**	1.13	1.13
Dividends per cumulative redeemable preferred share, series 7	**1.15**	1.15	1.15
Total assets	**35,225**	32,927	32,260
Total debt(2)	**5,747**	5,440	5,339
Net debt(2)	**2,881**	2,927	4,020

(1) *Funds from operations is a non-GAAP measure. The calculation of funds from operations changed in the second quarter of 2017. Prior periods have been revised to conform with the current period presentation. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*

(2) *Total debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt. Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Refer to Section 9.3 for reconciliations to the corresponding GAAP measures.*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is a Canadian integrated energy company and is based in Calgary, Alberta. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares Series 1, Series 2, Series 3, Series 5 and Series 7 are listed under the symbols "HSE.PR.A", "HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The Company operates in Canada, the United States and the Asia Pacific region with Upstream and Downstream business segments.

2.1 Corporate Strategy

The Company's business strategy is to focus on returns from investment in a deep portfolio of opportunities that can generate increased cash flow from operating activities and funds from operations.

The Company has two main businesses: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific") (Atlantic and Asia Pacific collectively, "Offshore").

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and natural gas liquids ("NGL") production from Western Canada, the Lloydminster upgrading and asphalt refining complex, Husky Midstream Limited Partnership (35 percent working interest and operatorship), and the Lima, Toledo (50 percent working interest) and Superior refineries in the U.S. midwest. Natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Atlantic and Asia Pacific. Each area generates high-netback production, with near and long-term investment potential.

2.2 Operations Overview and 2018 Highlights

Upstream Operations

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and NGL ("Exploration and Production") and the marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke. Additionally, Upstream operations include pipeline transportation, the blending of crude oil and natural gas and storage of crude oil, diluent and natural gas ("Infrastructure and Marketing"). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, Atlantic and Asia Pacific.

On January 16, 2019, the Company announced that its offer to acquire all of the outstanding common shares of MEG Energy Corp. expired, as the minimum tender threshold was not satisfied, and the Company decided not to extend its offer.

Exploration and Production

Thermal Developments

The Company continued to advance its inventory of thermal projects in 2018. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 124,200 bbls/day in 2018.

Lloyd Thermal Projects

The Company is phasing execution of its long-life thermal projects to optimize capital efficiency and project execution. In 2018, the Company completed two land deals to create two Thermal hubs, one at Spruce Lake, and one at Dee Valley. This has resulted in the expectation that the Edam Central project will be completed in 2022, rather than the previously disclosed timeframe of late 2021, and in Westhazel being reprioritized.

The following table shows major projects and their status as at December 31, 2018:

Project Name	Estimated Production (bbls/day)	Expected Project Production Date	Project Status
Rush Lake 2	10,000	First quarter of 2019	Completed ahead of schedule with first production achieved in October 2018 and nameplate capacity of 10,000 bbls/day reached in November 2018.
Dee Valley	10,000	Fourth quarter of 2019	Work continued, with drilling of the second well pad completed and construction of the Central Processing Facility ("CPF") continuing ahead of schedule. As of the end of 2018, the CPF was 80 percent complete.
Spruce Lake Central	10,000	2020	Construction of the CPF commenced in 2018.
Spruce Lake North	10,000	Around the end of 2020	Site clearing was completed in 2018.
Spruce Lake East	10,000	Around the end of 2021	Sanctioned in November 2018, with regulatory approval received in 2019. Prioritized ahead of Westhazel.
Edam Central	10,000	2022	Regulatory permit was received in early January 2019.
Dee Valley 2	10,000	2023	Regulatory applications were submitted in 2018, with approval expected in 2019.
Westhazel	10,000	Reprioritized	Regulatory applications were submitted in 2018, with approval expected in 2019. Reprioritized in order to optimize thermal sequence.

In February 2019, the Pike's Peak thermal bitumen plant was closed down as it reached the end of its useful life. The plant achieved first production in September 1981 and produced 78 mmbbls over its useful life.

Tucker Thermal Project

Work to debottleneck the CPF and Tucker field was completed in the third quarter of 2018. Subsequently, production ramped up and nameplate capacity of 30,000 bbls/day was achieved in October 2018, with a daily production record of 31,700 bbls/day achieved in late November. Production for 2018 and December 2018 averaged 22,400 bbls/day and 27,500 bbls/day, respectively.

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta. While specific volume reductions are uncertain, production in the first quarter of 2019 could be impacted by as much as 5,000 bbls/day.

Sunrise Energy Project

Total annual production in 2018 averaged 50,000 bbls/day (25,000 bbls/day Husky working interest). During the fourth quarter of 2018, maintenance activities were completed and the project reached its nameplate capacity of 60,000 bbls/day. Record production of 62,600 bbls/day was achieved in late December. December production averaged 59,000 bbls/day (29,500 bbls/day Husky working interest).

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta. While specific volume reductions are uncertain, production in the first quarter of 2019 could be impacted by as much as 15,000 bbls/day (7,500 bbls/day Husky working interest).

Non-Thermal Developments

The Company is managing the natural decline in Cold Heavy Oil Production with Sand ("CHOPS") operations with an active optimization program as well as using waterflooding and polymer injection technology.

Production in 2019 is expected to be impacted by government-mandated production curtailment in Alberta.

Cold and Enhanced Oil Recovery

In 2018, the Company sanctioned a full field polymer injection project at Aberfeldy and has opportunities to expand to other areas.

During the year, the Company operated five carbon dioxide ("CO_2") injection enhanced oil recovery ("EOR") pilot projects and a CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO_2 is used in the ongoing EOR piloting program. The Company is also piloting several types of CO_2 capture technology at its Lashburn facility in Saskatchewan.

Western Canada

The Company continues to execute its resource play strategy in Western Canada to advance developments in the Spirit River (predominantly Wilrich) and Montney formations.

Oil and Natural Gas Resource Plays

A drilling program targeting the Spirit River Formation, in the Ansell and Kakwa areas, continued with 21 wells drilled in 2018, and 25 completed.

A drilling program targeting the oil and liquids-rich gas Montney Formation in the Wembley and Karr areas is continuing with seven wells drilled in 2018, and six completed.

Asia Pacific

The Company's Asia Pacific business produces natural gas and NGL in the South China Sea and the Madura Strait offshore Indonesia. Natural gas is sold into the South China and East Java markets under long-term contracts with set prices that include escalation factors. NGL in both regions are sold at market prices.

The Company's interests include the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26, and Blocks 15/33, 16/25, 22/11 and 23/07 located in the South China Sea. The Madura Strait consists of the operating BD field, the MDA, MBH, MDK and MAC developments and three additional discoveries. The Company has rights to additional exploration blocks offshore Taiwan and Indonesia, and has signed a Strategic Cooperation Agreement with China National Offshore Oil Corporation Limited ("CNOOC") on two offshore areas in the northern part of the South China Sea for additional exploration opportunities in the future.

The Company continues to develop its contracted price natural gas business in China and Indonesia, further protecting the Company from commodity price instability.

China

Block 29/26

Total production from Liwan 3-1 and Liuhua 34-2 averaged 79,900 boe/day (39,200 boe/day Husky working interest) in 2018. Production consisted of natural gas production of 377 mmcf/day and NGL production of 17,100 bbls/day.

Construction continues at Liuhua 29-1, the third deepwater gas field of the Liwan Gas Project. All of the major contracts have been executed and detailed design work is underway. The Environment Impact Assessment was approved by the Ministry of Ecology and Environment in January 2019. Drilling of the remaining three wells is expected to commence in the first quarter of 2019, which will add to the four previously drilled wells. First gas production from this seven-well development is expected around the end of 2020, with target production of 45 mmcf/day of natural gas (Husky working interest) and 1,800 bbls/day of NGL (Husky working interest) when fully ramped up. The Company holds a working interest of 75 percent in this field development.

Blocks 15/33 and 16/25

The Company is progressing commercial development plans following the successful drilling and testing of an exploration well on Block 15/33.

During the third quarter of 2018, the Company drilled one exploration well at the nearby exploration Block 16/25 which encountered non-commercial hydrocarbons. Additional evaluation work is being conducted and a second exploration well may be drilled in the 2020 timeframe.

The Company is the operator of both blocks with a working interest of 100 percent during the exploration phase. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Blocks 22/11 and 23/07

The Company and CNOOC signed two Production Sharing Contracts ("PSCs") for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea in the first half of 2018. The Company is the operator of both blocks with a working interest of 100 percent during the exploration phase. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Block DW-1

During 2017, on Block DW-1 offshore Taiwan, the Company completed the acquisition of three-dimensional seismic survey data. Analysis of the data is ongoing to identify potential drilling prospects on the block.

Indonesia

Madura Strait

The BD Project achieved its total daily sales target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest) in the third quarter of 2018. Total natural gas production averaged 78 mmcf/day (31 mmcf/day Husky working interest) and NGL production averaged 6,200 bbls/day (2,500 bbls/day Husky working interest) in 2018.

At the MDA and MBH fields, the two shallow water platforms have been fully installed and preparations are underway to drill the five MDA and two MBH field production wells in 2019. Gas production and sales are expected to commence in the 2020 timeframe, following completion of the Floating Production Unit ("FPU") which will be used to process and compress the gas. Subsequently, an additional shallow water field, named MDK, is scheduled to be developed and tied into the FPU. The processed gas from these three fields will be tied directly into the East Java subsea pipeline system and sold to the East Java market under long-term contracts with set prices that include escalation factors.

Pre-engineering activities and approvals progressed at the MAC field, where an approved Plan of Development is in place. Additional discoveries in the region are being evaluated for potential development.

Anugerah

During 2015, the Company acquired two-dimensional and three-dimensional seismic survey data on the contract area, which was required during the first three years of the PSC. An analysis of that data and offset block information indicates that drilling is not economic and the block will be relinquished.

Atlantic

The Company's Atlantic portfolio has short and long-term opportunities that provide for high return production growth off the coast of Newfoundland and Labrador.

White Rose Field and Satellite Extensions

Project activity continues to ramp-up on the West White Rose Project. Construction of the concrete gravity structure began in the first half of 2018 at the purpose-built graving dock in Argentia, Newfoundland and Labrador. The structure's base slab was completed in mid-September and the structure was poured to a height of 46 metres during the 2018 construction season. First production is expected in 2022.

The Company continues to progress a subsea program to offset natural reservoir declines through infill drilling and workover operations at the White Rose field and satellite extensions. During the third quarter of 2018, two well workovers were completed. Two additional infill wells are being completed and are expected to be brought online before mid-year 2019, instead of the previously stated timeframe of the fourth quarter of 2018.

In late January 2019, the Company began a staged ramp-up of production at the White Rose field. The field had been shut-in since mid-November, after a flowline connector failed near the South White Rose Extension, causing a spill of approximately 250 cubic metres of oil. The Company and its certifying authority have completed inspections of the *SeaRose* floating production, storage and offloading ("FPSO") vessel as well as subsea infrastructure. Regulatory approval has been received for plans to recover the damaged flowline connector. An investigation into the cause of the incident is underway.

Atlantic Exploration

The Company continued to evaluate the results of a recent discovery at the A-24 exploration well north of the White Rose field and further delineation in the area is planned. The Company has a 68.875 percent ownership interest, with partners Suncor Energy and Nalcor Energy Oil and Gas holding 26.125 percent and five percent, respectively.

Infrastructure and Marketing

Husky Midstream Limited Partnership

Husky Midstream Limited Partnership ("HMLP") has approximately 2,200 kilometres of pipeline in the Lloydminster region, storage at Hardisty and Lloydminster, and other ancillary assets. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through Husky's Upgrader and Asphalt Refinery. The Hardisty Terminal acts as the exclusive blending hub for Western Canada Select ("WCS"). HMLP is in the process of diversifying its operations beyond the Lloydminster and Hardisty area and has commenced construction of the Ansell Corser Gas Plant.

LLB Direct – Cold Lake Gathering System to Hardisty

LLB Direct Pipeline and an associated 300,000-barrel operational tank at Hardisty came online in the fourth quarter of 2018, fulfilling an important component of HMLP's growth strategy in the Lloydminster region. The 20-inch line, with an initial 100,000 bbl/day capacity, provides the Company and third-party customers on the Cold Lake Gathering System with direct access to Hardisty, while simultaneously relieving congestion on the mainline system between Lloydminster and Hardisty.

Saskatchewan Gathering System Expansion

A multi-year expansion program is underway and will provide transportation of diluent and heavy oil blend for several additional thermal plants.

Ansell Corser Gas Plant

The new gas processing plant is now under construction and is expected to add 120 mmcf/day of processing capacity when it is scheduled to come online in the fourth quarter of 2019.

Commodity Marketing

The Company has developed its commodity marketing operations to include the acquisition of third-party volumes to enhance the value of its midstream assets. The Company also markets both its own and third-party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. Additionally, the Company markets petroleum coke, a by-product from the Lloydminster Upgrader, and its Ohio and Wisconsin refineries.

Downstream Operations

Downstream operations in the Integrated Corridor in Canada include upgrading of heavy crude oil feedstock into synthetic crude oil ("Upgrading"), refining crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining of crude oil in the U.S. to produce and market diesel fuels, gasoline, jet fuel and asphalt ("U.S. Refining and Marketing"). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and are grouped together as the Downstream business segment due to the similar nature of their products and services.

The Company's Downstream operations target three primary objectives: increasing feedstock flexibility to bring the best-priced crude to the Company's refineries; improving flexibility in the range of its products to capitalize on opportunities; and enhancing market access to achieve the best returns. The Company's focused integration strategy helps to capture the margin on refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

Upgrading

The heavy oil upgrading facility, located in Lloydminster, Saskatchewan, has a throughput capacity of 82,000 bbls/day. The Lloydminster Upgrader produces synthetic crude oil, diluent and ultra low sulphur diesel. Synthetic crude oil is used as refinery feedstock for the production of transportation fuels in Canada and the U.S. In addition, the Lloydminster Upgrader recovers diluent, which is blended with the heavy crude oil and bitumen prior to pipeline transportation to reduce viscosity and facilitate its movement, and returns it to the field to be reused.

Canadian Refined Products

Lloydminster Asphalt Refinery

The Lloydminster Asphalt Refinery in Lloydminster, Alberta, has a throughput capacity of 29,000 bbls/day and is integrated with the local heavy oil and bitumen production, as well as transportation and upgrading infrastructure. The Company is the largest marketer of paving asphalt in western Canada.

Ethanol Plants

The Company is the largest producer of ethanol in western Canada. The Company has two ethanol plants, one in Lloydminster, Saskatchewan and one in Minnedosa, Manitoba, with combined capacity of 260 million litres per year.

Prince George Refinery

The Prince George Refinery in British Columbia has a throughput capacity of 12,000 bbls/day and produces low sulphur gasoline and ultra-low sulphur diesel.

On January 8, 2019, the Company announced its intention to market and potentially sell the Prince George Refinery.

Retail and Commercial Network

The Company is a major regional motor fuel marketer with an average of 557 retail marketing locations in 2018, including bulk plants and travel centres, with strategic land positions in western Canada and Ontario.

On January 8, 2019, the Company announced its intention to market and potentially sell its Retail and Commercial Network.

U.S. Refining and Marketing

Lima Refinery

The Lima Refinery in Ohio has a crude oil throughput capacity, depending on the crude slate, of up to 175,000 bbls/day and produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products.

In 2016, the Company completed the first stage of the crude oil flexibility project and the refinery is now able to process up to 10,000 bbls/day of heavy crude oil feedstock. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from western Canada when completed, providing the ability to swing between light and heavy crude oil feedstock.

The timing of completion for the crude oil flexibility project is expected to be late 2019. This schedule coordinates project work with normal maintenance to provide higher levels of sustained production.

BP-Husky Toledo Refinery

The BP-Husky Toledo Refinery in Ohio has a nameplate throughput capacity of 160,000 bbls/day and produces low sulphur gasoline, ultra-low sulphur diesel, aviation fuels, and by-products. The crude oil refinery is owned 50 percent by the Company and 50 percent by BP Corporation North America Inc. ("BP"), and is operated by BP. The Company and BP completed a feedstock optimization project in 2016, allowing the refinery to process up to 70,000 bbls/day of high content naphthenic acids ("high-TAN") crude oil to support production from the Sunrise Energy Project. The refinery's nameplate capacity remained unchanged.

Superior Refinery

The Superior Refinery has a permitted throughput capacity of 50,000 bbls/day and an operating capacity of 45,000 bbls/day as configured. The refinery produces motor fuel products and asphalt from light and heavy crude oil originating from North Dakota and western Canada.

2.3 Superior Refinery Incident

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround. Operations at the refinery remain suspended. An engineering contractor has been appointed to oversee design work and rebuild of the refinery. The rebuild will commence once design work is complete and permits are obtained. Operations are expected to resume in 2020.

As at December 31, 2018, the Company derecognized $56 million of assets damaged in the incident in the U.S. Refining and Marketing segment. In addition, the Company accrued pre-tax insurance recoveries for property damage, rebuild costs, business interruption and clean-up costs associated with the incident of $468 million.

2.4 Financial Strategic Plan

The Company is committed to ensuring it has sufficient liquidity, financial flexibility and access to long-term capital to fund its growth. The Company maintains undrawn committed term credit facilities with a portfolio of creditworthy financial institutions and other sources of liquidity to provide timely access to funding to supplement cash flow.

The Company intends to maintain a healthy balance sheet to provide financial flexibility. The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. Debt to funds from operations and debt to capital employed are both non-GAAP measures (refer to Sections 6.4 and 9.3). The Company is committed to retaining its investment grade credit ratings to support access to debt capital markets. The Company has taken measures to maintain its strong financial position through commodity cycles. Past measures included, but were not limited to, a reduction of budgeted capital spending, temporary suspension of the quarterly common share dividend, the sale of non-core assets in Western Canada and the continued transition to higher margin production. Refer to Section 6.0 for additional information on the Company's liquidity and capital resources.

On February 28, 2018, the Board of Directors reinstated the quarterly common share cash dividend of $0.075 per share. On July 26, 2018, the quarterly common share cash dividend was increased to $0.125 per share.

3.0 The 2018 Business Environment

The Company's operations were significantly influenced by domestic and international factors in 2018, including, but not limited to, the following:

- Global crude oil benchmarks strengthened in the first half of 2018 due to market rebalancing, but weakened towards the end of the year due to record levels of oil production from the world's largest producers leading to increased global inventories, combined with uncertainties regarding future global demand.
- North American natural gas benchmarks continued to be weak in 2018 due to infrastructure constraints combined with lower demand for Canadian natural gas in the U.S. as a result of increased U.S. shale oil production.
- A continued emphasis on the environment, the impacts of climate change, health and safety, enterprise risk management, resource sustainability and corporate social responsibility concerns.
- Transportation constraints on crude oil produced in western Canada. The oil and gas industry continues to work with stakeholders to develop a strong network of transportation infrastructure including pipelines, rail, marine and trucks. The development of a strong infrastructure network continues to be an important challenge for the industry to obtain market access for the growing supply of crude oil from the western Canadian oil sands.
- On December 2, 2018, the Government of Alberta set province-wide mandatory oil production cuts in an attempt to rebalance the market. This curtailment was effective as of January 1, 2019, and is expected to continue through 2019.
- Alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore activity.

Major business factors are considered in the formulation of the Company's short and long-term business strategy.

The Company is exposed to a number of risks inherent in the exploration for, and development, production, marketing, transportation, storage, refining, and sale of, crude oil, liquids-rich natural gas and related products. For a discussion on Risk and Risk Management, see Section 5.0 and the Company's Annual Information Form for the year ended December 31, 2018.

Average Benchmarks

Commodity prices, refining crack spreads and foreign exchange rates are some of the most significant factors that affect the results of the Company's operations. The following average benchmarks have been provided to assist in understanding the Company's financial results.

Average Benchmarks Summary		2018	2017
West Texas Intermediate ("WTI") crude oil[1]	*(US$/bbl)*	**64.77**	50.95
Brent crude oil[2]	*(US$/bbl)*	**70.97**	54.28
Light sweet at Edmonton	*($/bbl)*	**69.31**	62.91
WCS at Hardisty[3]	*(US$/bbl)*	**38.46**	38.98
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**39.33**	44.36
WTI/Lloyd crude blend differential	*(US$/bbl)*	**26.09**	11.76
Condensate at Edmonton	*(US$/bbl)*	**60.95**	51.57
NYMEX natural gas[4]	*(US$/mmbtu)*	**3.09**	3.11
Nova Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.45**	2.30
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**78.07**	66.22
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**87.08**	69.05
Chicago 3:2:1 crack spread	*(US$/bbl)*	**15.94**	16.31
U.S./Canadian dollar exchange rate	*(US$)*	**0.772**	0.771
Canadian $ Equivalents[5]			
WTI crude oil	*($/bbl)*	**83.90**	66.08
Brent crude oil	*($/bbl)*	**91.93**	70.40
WCS at Hardisty	*($/bbl)*	**49.82**	50.56
WTI/Lloyd crude blend differential	*($/bbl)*	**33.80**	15.25
NYMEX natural gas	*($/mmbtu)*	**4.00**	4.03

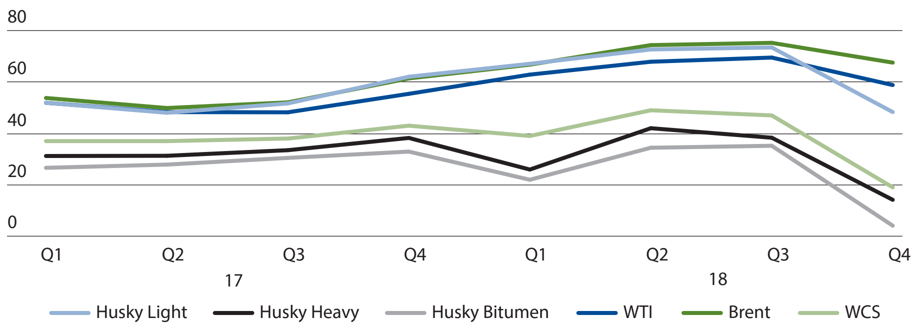
(1) *Calendar month average of settled prices for WTI at Cushing, Oklahoma.*
(2) *Calendar month average of settled prices for Dated Brent.*
(3) *WCS is a heavy blended crude oil, comprised of conventional and bitumen crude oils blended with diluent which terminals at Hardisty, Alberta. Quoted prices are indicative of the Index for WCS at Hardisty, Alberta, set in the month prior to delivery.*
(4) *Prices quoted are average settlement prices during the period.*
(5) *Prices quoted are calculated using U.S. dollar benchmark commodity prices and U.S./Canadian dollar exchange rates.*

As an integrated producer, the Company's profitability is largely determined by realized prices for crude oil and natural gas, margins on committed pipeline capacity and refinery margins, as well as the effect of changes in the U.S./Canadian dollar exchange rate. All of the Company's crude oil production and the majority of its natural gas production receive the prevailing market price. The price realized for crude oil is determined by North American and global factors. The price realized for natural gas production from Western Canada is determined primarily by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers. In Asia Pacific, the natural gas price is determined by fixed long-term sales contracts.

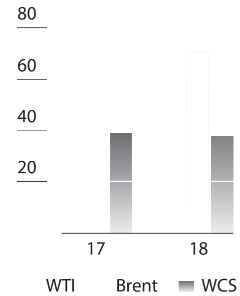
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil and bitumen. In the Upgrading business, heavy crude oil feedstock is processed into light synthetic crude oil. The Company's U.S. Refining and Marketing business processes a mix of different types of crude oil from various sources, but the mix is primarily light sweet crude oil at the Lima Refinery and approximately 62 percent heavy crude oil and bitumen feedstock at the BP-Husky Toledo Refinery. The Company's Retail and Commercial Network relies primarily on supply contracts to purchase refined products for resale in the retail distribution network, as well as production from the Prince George Refinery and diesel from the Lloydminster Upgrader.

Crude Oil Benchmarks

West Texas Intermediate, Brent, Western Canada Select and Husky Average Crude Oil Prices
(US$/bbl)



Average WTI, Brent and WCS
(US$/bbl)



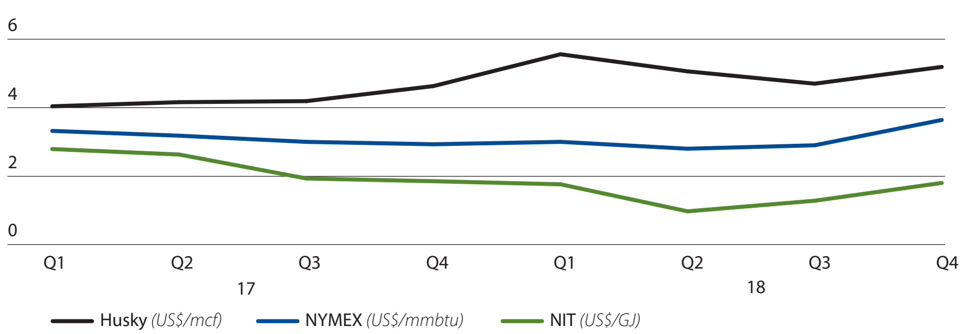
Global crude oil benchmarks strengthened in the first half of 2018 due to market rebalancing, but weakened towards the end of the year due to record levels of oil production from the world's largest producers leading to increased global inventories, combined with uncertainties regarding future global demand. Furthermore, the WCS benchmark weakened towards the end of 2018 primarily due to an oversupply of Canadian crude oil resulting from continued transportation constraints. Consequently the WCS benchmark traded at a greater discount compared to other North American benchmarks. WTI averaged US$64.77/bbl in 2018 compared to US$50.95/bbl in 2017. Brent averaged US$70.97/bbl in 2018 compared to US$54.28/bbl in 2017. WCS averaged US$38.46/bbl in 2018 compared to US$38.98/bbl in 2017.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada. The price received by the Company for crude oil production from Atlantic and for NGL production from Asia Pacific is primarily driven by the price of Brent. A portion of the Company's crude oil production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. The Company's crude oil and NGL production was 75 percent heavy crude oil and bitumen in 2018 compared to 70 percent in 2017.

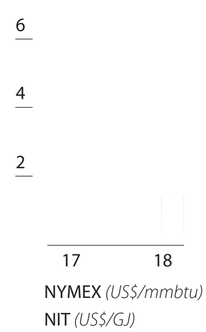
The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton increased in 2018 compared to 2017, primarily due to the increase in crude oil benchmark pricing.

Natural Gas Benchmarks

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



Average NYMEX and NIT



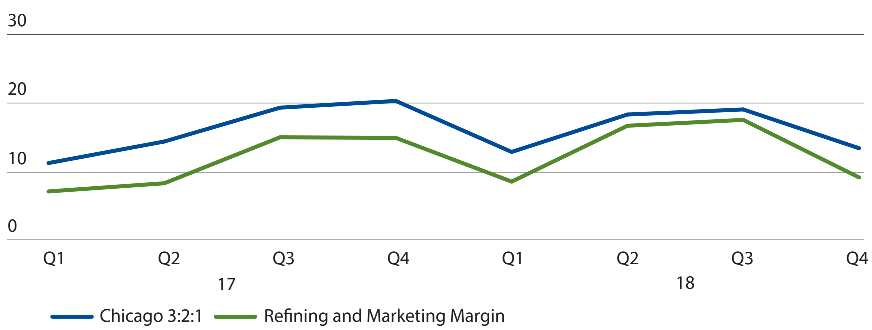
The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is determined by long-term contracts that include escalation factors.

The NIT natural gas price benchmark decreased in 2018 compared to 2017, primarily due to the continued oversupply of natural gas in North America.

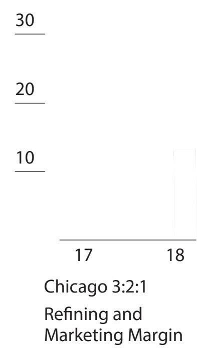
North American natural gas is consumed internally by the Company's Upstream and Downstream operations, helping to mitigate the impact of weak natural gas benchmark prices on results.

Refining Benchmarks

Chicago Average Crack Spread and Husky Realized U.S. Refining and Marketing Margin
(US$/bbl)



Average Crack Spread
(US$/bbl)



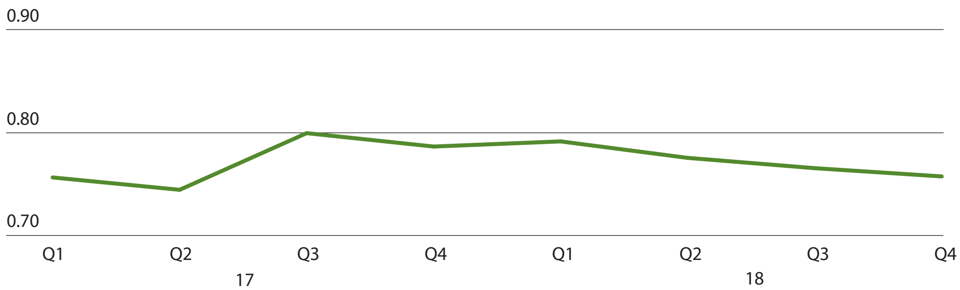
The Chicago 3:2:1 crack spread is a key indicator for U.S. refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs or the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 crack spread. The Chicago 3:2:1 crack spread is based on last in first out ("LIFO") accounting, which is a non-GAAP measure (refer to Section 9.3).

The Chicago 3:2:1 crack spread is a gross margin based on the prices of unblended fuels. The cost of purchasing Renewable Identification Numbers ("RINs") or physically blending biofuel into a final gasoline or diesel product has not been deducted from the Chicago 3:2:1 gross margin. The market value of gasoline or distillate that has been blended may be lower than the value of unblended petroleum products given the value a buyer of unblended petroleum can gain by generating RINs through blending. The Company sells both blended and unblended fuels with the goal of maximizing margins net of RINs purchases.

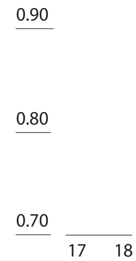
The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima, BP-Husky Toledo and Superior refineries contain between 13 and 38 percent of other products that are sold at discounted market prices compared to gasoline and distillate. The Company's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Foreign Exchange

Average U.S./Canadian Dollar Exchange Rate
(US$ per Cdn$)



Average U.S./Canadian Dollar Exchange Rate
(US$ per Cdn$)



The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities and refined products whose prices are determined by reference to U.S. benchmark prices. The majority of the Company's non-hydrocarbon related expenditures are denominated in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and Asia Pacific operations and U.S. dollar denominated debt. The Canadian dollar averaged US$0.772 in 2018 compared to US$0.771 in 2017.

A portion of the Company's long-term sales contracts in Asia Pacific are priced in Chinese Yuan ("RMB"). An increase in the value of RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of natural gas commodities in the region. The Canadian dollar averaged RMB 5.104 in 2018 compared to RMB 5.208 in 2017.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2018 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2018 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2018. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are indicative for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	2018 Average	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	**64.77**	*US$1.00/bbl*	**96**	**0.10**	**70**	**0.07**
NYMEX benchmark natural gas price[5]	**3.09**	*US$0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/Lloyd crude blend differential[6]	**26.09**	*US$1.00/bbl*	**(7)**	**(0.01)**	**(5)**	**(0.01)**
Canadian asphalt margins	**27.82**	*Cdn $1.00/bbl*	**10**	**0.01**	**8**	**0.01**
Canadian light oil margins	**0.042**	*Cdn $0.005/litre*	**14**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**15.94**	*US$1.00/bbl*	**112**	**0.11**	**87**	**0.09**
Exchange rate (US $ per Cdn $)[3][7]	**0.772**	*US$0.01*	**(59)**	**(0.06)**	**(44)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as of December 31, 2018.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent-based production.*
(5) *Includes impact of natural gas consumption by the Company.*
(6) *Excludes impact on Canadian asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

4.0 Results of Operations

4.1 Segment Earnings

Segmented Earnings	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[(1)]	
($ millions)	**2018**	2017	**2018**	2017	**2018**	2017
Upstream						
Exploration and Production	**288**	239	**223**	174	**2,656**	1,476
Infrastructure and Marketing	**780**	118	**567**	86	**—**	—
Downstream						
Upgrading	**496**	151	**361**	110	**62**	230
Canadian Refined Products	**216**	142	**158**	104	**74**	87
U.S. Refining and Marketing	**619**	371	**481**	234	**665**	313
Corporate	**(471)**	(597)	**(333)**	78	**121**	114
Total	**1,928**	424	**1,457**	786	**3,578**	2,220

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the year. Includes Exploration and Production assets acquired through acquisition, but excludes assets acquired through corporate acquisition.*

4.2 Upstream

Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	**2018**	2017
Gross revenues	**4,330**	4,978
Royalties	**(335)**	(363)
Net revenues	**3,995**	4,615
Production, operating and transportation expenses	**1,527**	1,650
Selling, general and administrative expenses	**296**	265
Depletion, depreciation, amortization and impairment ("DD&A")	**1,811**	2,237
Exploration and evaluation expenses	**149**	146
Gain on sale of assets	**(2)**	(42)
Other – net	**(120)**	6
Share of equity investment gain	**(51)**	(12)
Financial items	**97**	126
Provisions for income taxes	**65**	65
Net earnings	**223**	174

Exploration and Production net revenues decreased by $620 million in 2018 compared to 2017, primarily due to lower average realized sales prices combined with lower production, both of which are described in more detail below.

Selling, general and administrative expenses increased by $31 million in 2018 compared to 2017, primarily due to higher employee costs.

Gain on sale of assets decreased by $40 million in 2018 compared to 2017, primarily due to the disposition of select legacy assets in Western Canada in 2017.

Other – net for Exploration and Production increased by $126 million in 2018 compared to 2017, primarily due to profit or loss elimination between segments.

Share of equity investment gain increased by $39 million in 2018 compared to 2017, primarily due to the investment in the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method. The BD Project reached first production in the third quarter of 2017.

Financial items decreased by $29 million in 2018 compared to 2017, primarily due to higher capitalized interest expense due to thermal projects and West White Rose project.

Average Sales Prices Realized

Average Sales Prices Realized	2018	2017
Crude oil and NGL *($/bbl)*		
Light & Medium crude oil	**83.71**	67.36
NGL[(1)]	**55.72**	44.18
Heavy crude oil	**39.26**	43.38
Bitumen	**30.17**	38.20
Total crude oil and NGL average	**42.16**	46.09
Natural gas average *($/mcf)*[(1)]	**6.64**	5.52
Total average *($/boe)*	**41.50**	42.47

(1) *Reported average NGL and natural gas prices include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

The average sales prices realized by the Company for crude oil and NGL production decreased by nine percent in 2018 compared to 2017, primarily due to widening of the Canadian light/heavy oil differential.

The average sales prices realized by the Company for natural gas increased by 20 percent in 2018 compared to 2017. The increase was primarily due to a higher percentage of fixed priced natural gas production from both the Liwan Gas Project and BD Project relative to total natural gas production.

Daily Gross Production

Daily Gross Production	2018	2017
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light and Medium crude oil	**9.4**	12.1
NGL	**12.0**	10.5
Heavy crude oil	**36.8**	44.4
Bitumen[(1)]	**124.2**	119.1
	182.4	186.1
Atlantic		
White Rose and Satellite Fields – light crude oil	**17.4**	30.0
Terra Nova – light crude oil	**4.0**	4.0
	21.4	34.0
Asia Pacific		
Wenchang – light crude oil	**—**	5.3
Liwan and Wenchang – NGL[(2)]	**8.4**	7.0
Madura – NGL[(3)]	**2.5**	0.6
	10.9	12.9
	214.7	233.0
Natural gas *(mmcf/day)*		
Western Canada	**291.0**	378.2
Asia Pacific		
Liwan[(2)]	**184.8**	152.9
Madura[(3)]	**31.2**	8.0
	216.0	160.9
	507.0	539.1
Total *(mboe/day)*	**299.2**	322.9

(1) *Bitumen consists of production from thermal developments in Lloydminster, the Tucker Thermal Project located near Cold Lake, Alberta and the Sunrise Energy Project.*
(2) *Reported production volumes include Husky's working interest production from the Liwan Gas Project (49 percent).*
(3) *Reported production volumes include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

Crude Oil and NGL Production

Crude oil and NGL production decreased by 18.3 mbbls/day, or eight percent, in 2018 compared to 2017. The decrease was primarily due to lower production in Atlantic due to the suspension of operations on the *SeaRose* FPSO vessel in January and November 2018, a high water cut well at North Amethyst combined with natural well declines, a reduction of heavy crude oil production due to natural declines and reduced optimization activities in the Company's non-thermal developments, lower crude oil production in Asia Pacific due to the expiry of the Company's participation in the Wenchang oilfield PSC in late 2017, and lower production in Western Canada as a result of the disposition of select legacy assets in 2017. The decreases were partially offset by increased bitumen production from the Company's thermal projects, combined with increased NGL production in Asia Pacific and Western Canada.

Natural Gas Production

Natural gas production decreased by 32.1 mmcf/day, or six percent, in 2018 compared to 2017. In Western Canada, natural gas production decreased by 87.2 mmcf/day, primarily due to the disposition of select legacy assets in 2017. In Asia Pacific, natural gas production increased by 55.1 mmcf/day, primarily due to increased gas demand at the Liwan Gas Project and higher production from the BD Project.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	**2018**	2017
Crude oil and NGL		
Light & Medium crude oil	**22**	25
NGL[(1)]	**10**	6
Heavy crude oil	**11**	14
Bitumen	**29**	33
Crude oil and NGL	**72**	78
Natural gas[(1)]	**28**	22
Total	**100**	100

(1) *Reported average NGL and natural gas revenue include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

2019 Production Guidance and 2018 Actual

	Guidance	**Year ended December 31**	Guidance
Gross Production	2019	**2018**	2018
Canada			
Light & Medium crude oil *(mbbls/day)*	29 - 31	**31**	35 - 36
NGL *(mbbls/day)*	12 - 13	**12**	10 - 11
Heavy crude oil & bitumen *(mbbls/day)*	155 - 163	**161**	162 - 164
Natural gas *(mmcf/day)*	297 - 307	**291**	285 - 290
Canada total *(mboe/day)*	246 - 258	**252**	255 - 259
Asia Pacific			
Light crude oil *(mbbls/day)*	3 - 3	**—**	0 - 0
NGL *(mbbls/day)*[(1)]	6 - 7	**11**	10 - 11
Natural gas *(mmcf/day)*[(1)]	210 - 220	**216**	210 - 215
Asia Pacific total *(mboe/day)*	44 - 47	**47**	45 - 46
Total *(mboe/day)*	290 - 305	**299**	300 - 305

(1) *Includes Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

Total production for the year ended December 31, 2018 was marginally under the production guidance, primarily due to the factors that impacted crude oil and NGL production discussed above. The expected total production volumes in 2019 will remain comparable to 2018 after factoring in the reductions associated with Government of Alberta curtailment and partial suspension of operations at the White Rose field in Atlantic. The 2019 production guidance reflects curtailment affecting production at the Tucker Thermal Project, the Sunrise Energy Project and the conventional heavy oil business.

Factors that could potentially impact the Company's production performance in 2019 include, but are not limited to:

- eventual outcome and impact of the government-mandated production curtailment in Alberta.
- changes in crude oil and natural gas prices such as increases in commodity pricing, which may result in the decision to accelerate near-term growth projects, or decreases in commodity pricing, which may result in the decision to temporarily shut-in production or delay capital expenditures.
- performance of recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields.
- unplanned or extended maintenance and turnarounds at any of the Company's operated or non-operated facilities, upgrading, refining, pipeline or offshore assets.
- business interruptions due to unexpected events such as severe weather, fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events.
- defaults by contracting parties whose services, goods or facilities are necessary for the Company's production.
- operations and assets which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalties *(Percent)*	**2018**	2017
Western Canada	**9**	7
Atlantic	**8**	9
Asia Pacific[1]	**7**	6
Total	**8**	7

[1] *Reported royalties include Husky's working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.*

Royalty rates for Western Canada increased by two percent in 2018 compared to 2017, primarily due to higher WTI prices for the majority of 2018. Royalty rates for Atlantic decreased by one percent in 2018 compared to 2017, primarily due to lower production combined with higher eligible costs. Royalty rates for Asia Pacific increased by one percent in 2018 compared to 2017, primarily due to higher production from the BD Project which has higher royalty rates than the Liwan Gas Project.

Operating Costs

Operating Costs *($ millions)*	**2018**	2017
Western Canada	**1,218**	1,331
Atlantic	**213**	213
Asia Pacific	**95**	94
Total	**1,526**	1,638
Per unit operating costs *($/boe)*	**14.00**	13.93

Total Exploration and Production operating costs were $1,526 million in 2018 compared to $1,638 million in 2017. Total per unit operating costs averaged $14.00/boe in 2018 compared to $13.93/boe in 2017. The increase in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Atlantic averaged $27.21/bbl in 2018 compared to $17.12/bbl in 2017. The increase in per unit operating costs was primarily due to lower production.

Per unit operating costs in Western Canada averaged $14.48/boe in 2018 compared to $14.67/boe in 2017. The decrease in per unit operating costs was primarily due to lower energy costs and the continued ramp-up at the Sunrise Energy Project.

Per unit operating costs in Asia Pacific averaged $5.53/boe in 2018 compared to $6.47/boe in 2017. The decrease in per unit operating costs was primarily due to higher production at the Liwan Gas and BD projects.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses *($ millions)*	**2018**	2017
Seismic, geological and geophysical	**102**	113
Expensed drilling	**41**	22
Expensed land	**6**	11
Total	**149**	146

Exploration and Evaluation expenses were $149 million in 2018 compared to $146 million in 2017.

Depletion, Depreciation, Amortization and Impairment

DD&A expense decreased by $426 million in 2018 compared to 2017, primarily due to lower production in 2018, the recognition of a pre-tax impairment charge of $173 million in 2017, and additional heavy oil and bitumen reserves bookings in the fourth quarter of 2017. In 2018, total DD&A excluding impairment averaged $16.99/boe compared to $17.61/boe in 2017.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in 2018 compared to 2017, reflecting increased spending across the portfolio. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[(1)] *($ millions)*	**2018**	2017
Exploration		
Western Canada	**99**	63
Thermal developments	**7**	8
Atlantic	**73**	67
Asia Pacific[(2)]	**52**	10
	231	148
Development		
Western Canada	**332**	196
Thermal developments	**874**	534
Non-thermal developments	**110**	106
Atlantic	**916**	417
Asia Pacific[(2)]	**148**	2
	2,380	1,255
Acquisitions		
Western Canada	**4**	25
Thermal developments	**41**	48
	45	73
Total	**2,656**	1,476

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

Western Canada

During 2018, $435 million (16 percent) was invested in Western Canada compared to $284 million (19 percent) in 2017. Capital expenditures in 2018 related primarily to resource play development targeting the Spirit River Formation in the Ansell and Kakwa areas and the Montney Formation in the Wembley and Karr areas.

Thermal Developments

During 2018, $922 million (35 percent) was invested in thermal developments compared to $590 million (40 percent) in 2017. Capital expenditures in 2018 related primarily to the development of the Rush Lake 2 Thermal Project, and construction work at the Dee Valley and Spruce Lake Central thermal projects.

Non-Thermal Developments

During 2018, $110 million (four percent) was invested in non-thermal developments compared to $106 million (seven percent) in 2017. Capital expenditures in 2018 related primarily to sustainment activities.

Atlantic

During 2018, $989 million (37 percent) was invested in Atlantic compared to $484 million (33 percent) in 2017. Capital expenditures in 2018 related primarily to the development of the West White Rose Project and sustainment and development activities at the White Rose field and satellite extensions.

Asia Pacific

During 2018, $200 million (eight percent) was invested in Asia Pacific compared to $12 million (one percent) in 2017. Capital expenditures in 2018 related primarily to the continued development of Liuhua 29-1, and the exploration of Blocks 15/33 and 16/25.

Exploration and Production Wells Drilled

Onshore Drilling Activity

The following table discloses the number of wells drilled during 2018 and 2017:

	2018		2017	
Wells Drilled *(wells)*[1]	**Gross**	**Net**	Gross	Net
Thermal developments	**150**	**140**	64	64
Non-thermal developments	**31**	**26**	29	27
Western Canada	**46**	**45**	36	33
Total	**227**	**211**	129	124

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*

Thermal developments consisted of drilling and completion activity related to the Sunrise Energy Project and the Dee Valley and Spruce Lake Central thermal projects. Western Canada drilling and completion activity increased primarily due to a drilling program targeting the Spirit River Formation in the Ansell and Kakwa areas, as well as a drilling program targeting the Montney Formation in the Wembley and Karr areas.

Offshore Drilling Activity

The following table discloses the Company's Offshore drilling activity during 2018:

Region	Well	Working Interest	Well Type
Atlantic	North Amethyst G-25 11	68.875 percent	Development
Atlantic	White Rose A-24	68.875 percent	Exploration
Asia Pacific	Block 15/33 XJ 34-3-2	100 percent	Exploration
Asia Pacific	Block 15/33 PY 3-6-1	100 percent	Exploration
Asia Pacific	Block 16/25 HZ 25-7-4	100 percent	Exploration

2019 Upstream Capital Expenditures Program

2019 Upstream Capital Expenditures Program *($ millions)*	
Thermal developments	**730 - 760**
Non-thermal developments	**100 - 110**
Western Canada	**180 - 190**
Atlantic	**1,120 - 1,190**
Asia Pacific[1]	**350 - 370**
Total Upstream capital expenditures	**2,480 - 2,620**

(1) *Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

The 2019 Upstream capital expenditures program reflects a focus on near-term and medium-cycle projects in the Integrated Corridor business, including further growing the Lloydminister thermal bitumen portfolio as well as the Ansell resource play in Western Canada. In the Offshore business, the capital expenditures program will support the continuation of construction at the Liuhua 29-1 field offshore China and the West White Rose Project in Atlantic.

The Company has budgeted $730 - $760 million in thermal developments for 2019, primarily for the development of the Dee Valley, Spruce Lake North and Spruce Lake Central thermal bitumen projects. Capital expenditures will also take place in support of environmental and regulatory work on Spruce Lake East which was sanctioned in the fourth quarter of 2018. The Company is making progress in its strategy to transition a greater percentage of production to long-life thermal bitumen production and the 2019 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted $100 - $110 million in non-thermal developments for 2019, primarily for sustainment activities.

The Company has budgeted $180 - $190 million in Western Canada for 2019, primarily for the planned drilling activities in the Spirit River Formation in the Ansell and Kakwa areas as well as in the Montney Formation, and sustainment and maintenance activities.

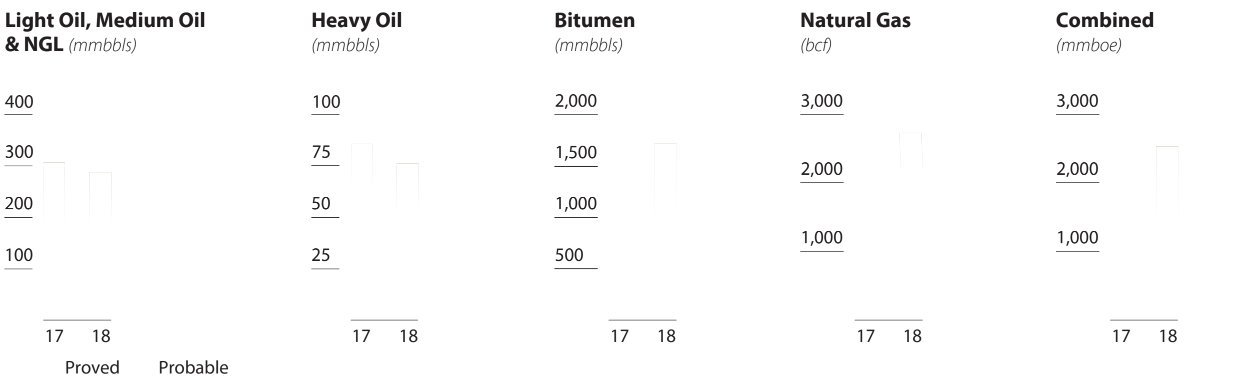
The Company has budgeted $1,120 - $1,190 million in Atlantic for 2019, primarily for the construction of the West White Rose Project.

The Company has budgeted $350 - $370 million in Asia Pacific in 2019, primarily for the continued development of the third field of the Liwan Gas Project, Liuhua 29-1.

Oil and Gas Reserves

The Company's reserves disclosure was prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") effective December 31, 2018 with a preparation date of January 31, 2019.

Proved and Probable Reserves at December 31:



Note: All Lloydminster thermal reserves are classified as bitumen.

The Company's complete oil and gas reserves disclosure, prepared in accordance with NI 51-101, is contained in the Company's Annual Information Form, which is available at www.sedar.com, and certain supplementary oil and gas reserves disclosure prepared in accordance with U.S. disclosure requirements is contained in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

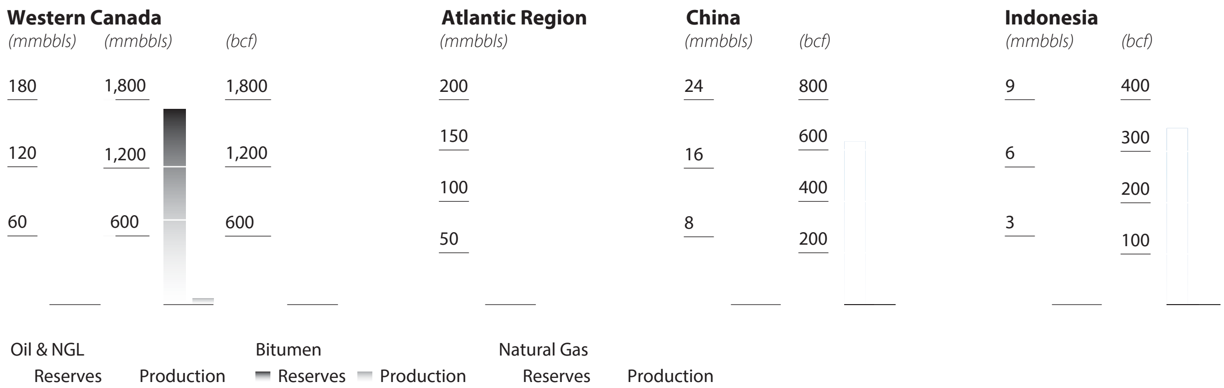
Sproule Associates Ltd. ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit and review of the Company's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion on January 31, 2019 stating that the Company's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

At December 31, 2018, the Company's proved oil and gas reserves were 1,471 mmboe, up from 1,301 mmboe at the end of 2017. The Company's 2018 reserves replacement ratio, defined as net additions divided by total production during the period, was 260 percent excluding economic revisions (255 percent including economic revisions).

Major changes to proved reserves in 2018 included:

- Discoveries, Extensions and Improved Recovery additions of 266 mmboe including 102 mmbbls at the Sunrise Energy Project from new locations as part of a full field optimized development plan, 63 mmbbls for two new Lloydminster thermal bitumen steam-assisted gravity drainage projects, first booking of Liuhua 29-1 of 31 mmboe, 43 mmboe in Ansell, Kakwa, North Blackstone, Wapiti and Wembley from new locations, and 8 mmbbls for additional reserves associated with the West White Rose Project.
- Technical revisions of 15 mmboe included 31 mmbbls added for the Lloydminster thermal bitumen projects and 9 mmboe added in China due to higher performance than last year's forecast. These were offset by a reduction of 23 mmbbls at the Sunrise Energy Project as a result of applying a more conservative estimate of the recovery factor early in the 50-year life of the field.

Proved Plus Probable Reserves and Production at December 31, 2018:



Reconciliation of Proved Reserves [(1)]

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [(2)]	Bitumen *(mmbbls)*[(2)]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves										
December 31, 2017	66	64	747	1,174	97	21	662	995	1,836	1,301
Technical revisions	(2)	2	8	4	(3)	2	47	7	51	15
Acquisitions	—	—	2	8	—	—	—	2	8	4
Dispositions	—	(1)	—	(2)	—	—	—	(1)	(2)	(1)
Discoveries, extensions and improved recovery	9	5	178	220	7	5	153	204	373	266
Economic factors	—	(3)	—	(10)	—	—	—	(3)	(10)	(5)
Production	(8)	(13)	(45)	(106)	(8)	(4)	(79)	(78)	(185)	(109)
Proved reserves December 31, 2018	**65**	**54**	**890**	**1,288**	**93**	**24**	**783**	**1,126**	**2,071**	**1,471**
Proved and probable reserves December 31, 2018	**80**	**76**	**1,722**	**1,751**	**177**	**30**	**984**	**2,085**	**2,735**	**2,541**
December 31, 2017	80	86	1,609	1,597	196	31	1,014	2,002	2,611	2,437

(1) *Numbers in the above table may not align with other disclosures due to rounding.*
(2) *Lloydminster thermal property reserves are classified as bitumen.*

Reconciliation of Proved Developed Reserves [(1)]

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [(2)]	Bitumen *(mmbbls)*[(2)]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves										
December 31, 2017	62	64	162	823	37	21	561	346	1,384	575
Technical revisions	(2)	2	2	2	(5)	3	46	—	48	9
Transfer from proved undeveloped	1	—	21	24	—	—	—	22	24	26
Acquisitions	—	—	—	8	—	—	—	—	8	2
Dispositions	(1)	—	—	(2)	—	—	—	(1)	(2)	(1)
Discoveries, extensions and improved recovery	4	4	2	63	—	—	—	10	63	20
Economic factors	—	(4)	—	(8)	—	—	—	(4)	(8)	(5)
Production	(8)	(13)	(45)	(106)	(8)	(4)	(79)	(78)	(185)	(109)
December 31, 2018	**56**	**53**	**142**	**804**	**24**	**20**	**528**	**295**	**1,332**	**517**

(1) *Number in the above tables may not align with other disclosures due to rounding.*
(2) *Lloydminster thermal property reserves are classified as bitumen.*

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary *($ millions)*	**2018**	2017
Gross revenues	**2,211**	1,976
Marketing and other	**668**	(40)
Expenses		
Purchases of crude oil and products	**2,087**	1,855
Production, operating and transportation expenses	**23**	13
Selling, general and administrative expenses	**5**	4
Depletion, depreciation, amortization and impairment	**—**	2
Loss on sale of assets	**—**	1
Other – net	**2**	(8)
Share of equity investment gain	**(18)**	(49)
Provisions for income taxes	**213**	32
Net earnings	**567**	86

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $235 million and $232 million, respectively, in 2018 compared to 2017, primarily due to increased volumes and prices.

Marketing and other increased by $708 million in 2018 compared to 2017, primarily due to crude oil marketing gains from widening location price differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline.

Share of equity investment gain decreased by $31 million in 2018 compared to 2017, primarily due to higher maintenance expense and higher depreciation from HMLP in 2018.

Provisions for income taxes increased by $181 million in 2018 compared to 2017, primarily due to higher earnings before income taxes in 2018.

4.3 Downstream

Upgrading

Upgrading Earnings Summary *($ millions, except where indicated)*	2018	2017
Gross revenues	**1,750**	1,440
Expenses		
Purchases of crude oil and products	**928**	983
Production, operating and transportation expenses	**195**	197
Selling, general and administrative expenses	**7**	9
Depletion, depreciation, amortization and impairment	**123**	99
Financial items	**1**	1
Provisions for income taxes	**135**	41
Net earnings	**361**	110
Upgrading throughput *(mbbls/day)*[(1)]	**75.6**	68.5
Total sales *(mbbls/day)*	**74.7**	68.5
Synthetic crude oil sales *(mbbls/day)*	**52.9**	49.8
Upgrading differential *($/bbl)*	**29.05**	18.66
Unit margin *($/bbl)*	**30.15**	18.28
Unit operating cost *($/bbl)*[(2)]	**7.07**	7.88

(1) *Throughput includes diluent returned to the field.*
(2) *Based on throughput.*

Upgrading operations add value by processing heavy crude oil into high value synthetic crude oil and low sulphur distillates. Upgrading profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil.

Upgrading gross revenues increased by $310 million in 2018 compared to 2017, primarily due to higher realized prices for synthetic crude oil and higher sales volumes as the Lloydminster Upgrader was in a major planned turnaround in the second quarter of 2017. The price of Husky Synthetic Blend averaged $75.55/bbl in 2018 compared to $67.05/bbl in 2017.

Upgrading feedstock purchases decreased by $55 million in 2018 compared to 2017, primarily due to the decrease in the average cost of heavy crude oil feedstock.

Upgrading DD&A increased by $24 million in 2018 compared to 2017, primarily due to a higher depletable base in 2018 resulting from the capitalization of turnaround costs in 2017.

Provisions for income taxes increased by $94 million in 2018 compared to 2017, primarily due to higher earnings before income taxes in 2018.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	**2018**	2017
Gross revenues	**3,412**	2,787
Expenses		
Purchases of crude oil and products	**2,760**	2,219
Production, operating and transportation expenses	**265**	256
Selling, general and administrative expenses	**47**	53
Depletion, depreciation, amortization and impairment	**115**	111
Gain on sale of assets	**(2)**	(5)
Other – net	**(1)**	(1)
Financial items	**12**	12
Provisions for income taxes	**58**	38
Net earnings	**158**	104
Number of fuel outlets[1]	**557**	518
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.7**	7.3
Fuel sales per retail outlet *(thousands of litres/day)*	**12.3**	12.1
Refinery throughput		
Prince George Refinery *(mbbls/day)*[2]	**10.7**	11.2
Lloydminster Refinery *(mbbls/day)*[2]	**27.1**	26.8
Ethanol production *(thousands of litres/day)*	**819.4**	804.8

(1) *Average number of fuel outlets for period indicated.*

(2) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*

Canadian Refined Products gross revenues increased by $625 million in 2018 compared to 2017, primarily due to higher product prices.

Canadian Refined Products purchases of crude oil and products increased by $541 million in 2018 compared to 2017, primarily due to higher commodity prices.

Provisions for income taxes increased by $20 million in 2018 compared to 2017, primarily due to higher earnings before income taxes in 2018.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	2018	2017
Gross revenues	**11,770**	9,355
Expenses		
Purchases of crude oil and products	**10,334**	8,059
Production, operating and transportation expenses	**795**	563
Selling, general and administrative expenses	**22**	15
Depletion, depreciation, amortization and impairment	**450**	354
Other – net	**(464)**	(21)
Financial items	**14**	14
Provisions for income taxes	**138**	137
Net earnings	**481**	234
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*[1]	**151.1**	172.2
BP-Husky Toledo Refinery throughput *(mbbls/day)*[1][2]	**71.1**	76.6
Superior Refinery throughput *(mbbls/day)*[1]	**11.7**	5.5
Refining and marketing margin *(US$/bbl crude throughput)*[3]	**13.03**	11.44
Refinery inventory *(mmbbls)*[4]	**6.9**	9.2

(1) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(2) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50 percent).*
(3) *Prior period has been restated to include impact of U.S. product marketing margin.*
(4) *Feedstock and refined products are included in refinery inventory.*

U.S. Refining and Marketing gross revenues increased by $2,415 million in 2018 compared to 2017, primarily due to higher refined product prices partially offset by lower sales volumes as the Lima Refinery completed a major planned turnaround in late 2018.

U.S. Refining and Marketing purchases of crude oil and products increased by $2,275 million in 2018 compared to 2017, primarily due to higher commodity prices partially offset by lower throughput volumes as the Lima Refinery completed a major planned turnaround in late 2018.

Production, operating and transportation expenses increased by $232 million in 2018 compared to 2017, primarily due to the acquisition of the Superior Refinery in late 2017 and the incident at the refinery in April 2018.

DD&A expense increased by $96 million in 2018 compared to 2017, primarily due to the derecognition of assets damaged during the incident at the Superior Refinery.

Other – net increased by $443 million in 2018 compared to 2017, primarily due to pre-tax insurance recoveries for property damage, rebuild costs, business interruption and clean-up costs associated with the incident at the Superior Refinery.

Downstream Capital Expenditures

In 2018, Downstream capital expenditures totalled $801 million compared to $630 million in 2017. In Canada, capital expenditures of $136 million related primarily to the scheduled partial turnaround at the Lloydminster Upgrader in the second quarter of 2018, and various reliability and environmental activities at the Lloydminster and Prince George refineries. In the U.S., capital expenditures of $665 million related primarily to the turnaround and crude oil flexibility project at the Lima Refinery, the turnaround at the Superior Refinery, and various reliability and environmental initiatives at the Lima and BP-Husky Toledo refineries.

4.4 Corporate

Corporate Summary *($ millions) income (expense)*	2018	2017
Production, operating and transportation expenses	**2**	—
Selling, general and administrative expenses	**(277)**	(304)
Depletion, depreciation, amortization and impairment	**(92)**	(79)
Other – net	**8**	(6)
Net foreign exchange gain (loss)	**14**	(6)
Finance income	**52**	32
Finance expense	**(178)**	(234)
Recovery of income taxes	**138**	675
Net earnings (loss)	**(333)**	78

The Corporate segment reported a net loss of $333 million in 2018 compared to net earnings of $78 million in 2017. The change was primarily due to the recognition of a $436 million deferred tax recovery in 2017, related to the reduction of the U.S. Federal corporate tax rate that took effect at the beginning of 2018.

Finance income increased by $20 million in 2018 compared to 2017, primarily due to interest on short-term investments.

Finance expense decreased by $56 million in 2018 compared to 2017, primarily due to lower interest expense in 2018 from the repayment of long term debt in late 2017.

Net foreign exchange gain increased by $20 million due to the items noted below.

Foreign Exchange Summary *($ millions, except where indicated)*	2018	2017
Non-cash working capital loss	**(3)**	(3)
Other foreign exchange gain (loss)	**17**	(3)
Net foreign exchange gain (loss)	**14**	(6)
U.S./Canadian dollar exchange rates:		
At beginning of year	**US$0.799**	US$0.745
At end of year	**US$0.733**	US$0.799

Included in the other foreign exchange gain (loss) are realized and unrealized gains and losses on working capital and intercompany financing. The foreign exchange gains and losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period. The Company manages its exposure to foreign currency fluctuations with the goal of minimizing the impact of foreign exchange gains and losses on the consolidated financial statements.

Consolidated Income Taxes

Consolidated Income Taxes *($ millions)*	2018	2017
Provisions for (recovery of) income taxes	**471**	(362)
Cash income taxes paid (recovered)	**37**	(41)

Consolidated income taxes were a provision of $471 million in 2018 compared to a recovery of $362 million in 2017. The increase in consolidated income taxes was primarily due to the recognition of a $436 million deferred tax recovery related to the U.S. tax reform changes enacted in December 2017, combined with higher earnings before income taxes in 2018.

5.0 Risk and Risk Management

5.1 Enterprise Risk Management

The Company's enterprise risk management program supports decision-making via comprehensive and systematic identification and assessment of risks that could materially impact the results of the Company. Through this framework, the Company builds risk management and mitigation into strategic planning and operational processes for its business units through the adoption of standards and best practices. The Company has developed an enterprise risk matrix to identify risks to its people, the environment, its assets and its reputation, and to systematically mitigate these risks to an acceptable level.

The Company attempts to mitigate its financial, operational and strategic risks to an acceptable level through a variety of policies, systems and processes. The following provides a list of the most significant risks relating to the Company and its operations.

5.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks with respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks by designing and building its facilities and conducting its operations in a safe and reliable manner using the Husky Operational Integrity Management System, an integrated management system that considers environmental requirements as well as process and occupational safety. Failure to manage the risks effectively could result in potential fatalities, serious injury, interruptions to activities or use of assets, damage to assets, environmental impact or loss of licence to operate. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices received for its refined products, crude oil, NGL and natural gas production. Lower prices for crude oil, NGL and natural gas could adversely affect the value and quantity of the Company's oil and gas reserves. The Company's reserves include significant quantities of heavier grades of crude oil that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining and transportation capacity for heavy crude oil and bitumen is limited and planned increases of North American heavy crude oil and bitumen production may create the need for additional heavy oil and bitumen refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on the Company's results of operations and financial condition, reduce the value and quantities of the Company's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that pipeline development projects or other transportation alternatives will provide sufficient transportation capacity and access to refining capacity to accommodate expected increases in North American heavy crude oil and bitumen production.

Prices for refined products and crude oil are based on world supply and demand. Supply and demand can be affected by a number of factors including, but not limited to, actions taken by the Organization of the Petroleum Exporting Countries ("OPEC"), non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, technological developments, prevailing weather patterns, government regulation and policies and the availability of alternate sources of energy.

The Company's natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's natural gas production is subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of natural gas available to specific market areas either from the wellhead of existing or accessible conventional or unconventional sources (such as from shale) or from storage facilities, technological developments, prevailing weather patterns, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

In certain instances, the Company will use derivative instruments to manage exposure to price volatility on a portion of its refined product, oil and gas production, inventory or volumes in long-distance transit. The Company may also use firm commitments for the purchase or sale of crude oil and natural gas.

The fluctuations in refined products, crude oil and natural gas prices are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

Reservoir Performance Risk

Lower than projected reservoir performance on the Company's key growth projects could have a material adverse effect on the Company's results of operations, financial condition, business strategy and reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

In order to maintain the Company's future production of crude oil, natural gas and NGL and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted while the associated unit operating costs increase. To mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. Maintaining an inventory of projects that can be developed depends upon, but is not limited to, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completion of long lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

Restricted Market Access and Pipeline Interruptions

The Company's results of operations and financial condition depend upon the Company's ability to deliver products to the most attractive markets. The Company's results of operations could be materially adversely affected by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets as well as regulatory and/or other marketplace barriers. Interruptions and restrictions may be caused by the inability of a pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. With growing oil production across North America and the limited availability of infrastructure to carry the Company's products to the marketplace, oil and natural gas transportation capacity is expected to be restricted in the next few years. Restricted market access may potentially have a material adverse effect on the Company's results of operations, financial condition and business strategy. Unplanned shutdowns and closures of its refineries or Upgrader may limit the Company's ability to deliver product with a material adverse effect on sales and results of operations.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact the Company's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility, office or offshore vessel/installation owned or operated by the Company could result in the interruption or cessation of key elements of the Company's operations. Outcomes of such incidents could have a material adverse effect on the Company's results of operations, financial condition and business strategy.

International Operations

International operations can expose the Company to uncertain political, economic and other risks. The Company's operations in certain jurisdictions may be materially adversely affected by political, economic or social instability or events. These events may include, but are not limited to, onerous fiscal policy, renegotiation or nullification of agreements and treaties, imposition of onerous regulation, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and behaviour of public officials, joint venture partners or third-party representatives that could result in lost business opportunities for the Company. This could materially adversely affect the Company's interest in its foreign operations, results of operations and financial condition.

Major Project Execution

The Company manages a variety of oil and gas projects ranging from Upstream to Downstream assets across its global portfolio. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of the Company's projects. Project risks may result in extended stakeholder consultation, additional environmental assessments and public hearings which may delay necessary environmental and regulatory approvals. Project risks may also manifest through schedule delays, cost overruns and commodity price drops. Some risks can impact the Company's safety and environmental records thereby negatively affecting the Company's reputation and social license to operate.

Litigation, Administrative Proceedings and Regulatory Actions

The Company may be subject to litigation, claims, administrative proceedings and regulatory actions, which may be material. Such claims could relate to environmental damage, failure to comply with applicable laws and regulations, breach of contract, tax, bribery and employment matters, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary suspensions of operations or the inability to engage in certain operations or transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on the Company's reputation, financial condition and results of operations. The defence to such claims may be costly and could divert management's attention away from day-to-day operations.

Partner Misalignment

Joint venture partners operate a portion of the Company's assets in which the Company has an ownership interest. This can reduce the Company's control and ability to manage risks. The Company is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project or if partners were unable to fund their contractual share of the capital expenditures, a project could be delayed and the Company could be partially or totally liable for its partner's share of the project.

Reserves Data, Future Net Revenue and Resource Estimates

The reserves data contained or referenced in the MD&A represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's Upstream assets. Reserves estimates support various investment decisions about the development and management of oil and gas properties. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the effects of regulation by government agencies, including with respect to royalty payments, all of which may vary considerably from actual results. The Company uses all available information at the effective date of the evaluation and internal qualified reserves evaluators to prepare the reserves estimates. As required by NI 51-101, the Company obtains the opinion of an independent reserves auditor on the Company's reserves. The audit covers more than 75 percent of the future net revenue discounted at 10 percent attributable to proved plus probable reserves with the remainder reviewed by the independent qualified reserves auditor. However, given the best technical information and evaluation techniques, all such estimates are still to some degree uncertain. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Estimates of the economically recoverable oil and gas reserves attributable to any particular property or group of properties, and estimates of future net revenues expected therefrom, may differ substantially from actual results even though the total company reserves are shown to be reliable through the historical total company technical reserves revisions. The Company has a diverse portfolio of assets by product type, reservoir type and location which is a factor in mitigating specific property risks. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and could have a material adverse effect on the Company's reputation, investor confidence and ability to deliver on its growth business strategy.

Government Regulation

Given the scope and complexity of the Company's operations, the Company is subject to regulations and interventions by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations, development or exploratory activities. As these governments continually balance competing demands from different interest groups and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulations could impact the Company's existing and planned projects as well as impose costs of compliance and increase capital expenditures and operating expenses. Examples of the Company's regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy policies, uncertain climate policies, uncertain environmental and safety policies, penalties, taxes, royalties, government fees, reserves access, limitations or increases in costs relating to the exportation of commodities, production restrictions, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of contract rights, limitations on control over the development and abandonment of fields and loss of licences to operate.

Environmental Regulation

Changes in environmental regulations could have a material adverse effect on the Company's results of operations, financial condition and business strategy by requiring increased capital expenditures and operating costs or by impacting the quality, formulation or demand of products, which may or may not be offset through market pricing.

The Company anticipates further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, increased compliance costs and approval delays for critical licences and permits.

Climate Change Regulation

Climate change regulations may become more onerous over time as governments implement policies to further reduce greenhouse gases ("GHG") emissions. As part of long range planning, the Company assesses future compliance costs associated with regulations of GHG emissions in its operations and the evaluation of future projects, based on the Company's outlook for carbon pricing under current and pending regulations. The impact of recently announced regulations is being evaluated as provinces and the federal government finalize carbon pricing regulations. As these regulations continue to evolve, they could have a material adverse effect on the Company's competitiveness, financial condition and results of operations through increased capital and operating costs and change in demand for refined products such as transportation fuels. The Company continues to monitor international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and other emerging regulations in the jurisdictions in which the Company operates.

The Alberta Climate Leadership Plan began to be implemented in 2017. This plan includes an economy-wide carbon levy, rising to $30 per tonne in 2018 which applies to the Lloydminster Refinery, as well as a Carbon Competitiveness Incentive Regulation ("CCIR") that manages emissions at large final emitting facilities ("LFEs") including the Tucker Thermal Project and Sunrise Energy Project. Under the previous Specified Gas Emitters Regulation, which expired at the end of 2017, the Tucker Thermal Project generated over 500,000 tonnes of credits due to improved emission intensity performance. These credits are eligible to offset future compliance obligations under the CCIR. These regulations are not anticipated to have a material impact over the duration of the Company's five-year long-range plan. The CCIR is due for review in 2020, along with the federal carbon policy. Uncertainty regarding future regulations, including carbon price and the details of implementing the oil sands emission limit, make it difficult to predict the potential future impact on the Company.

In December 2017, the Government of Saskatchewan released "Prairie Resilience" a policy paper on climate change strategy in which it outlines multiple commitments across five areas designed to make Saskatchewan more resilient to the climatic, economic and policy impacts of climate change. As part of this strategy, the government developed output-based performance standards for large industrial emitters and a Climate Resilience Measurement Framework. The large industrial emitters regulations will apply to the Company's Lloydminster Upgrader and ethanol plant and Saskatchewan thermal projects to reduce emissions while considering the economic competitiveness of these sectors. The smaller facilities (emitting under 25,000 tonnes/year) will be exposed to the federal carbon levy. The cost impacts of this levy on the Company's cold heavy oil production may be measurable.

The cost of compliance with British Columbia's $35 per tonne carbon tax (increasing to $40 on April 1, 2019) and the Renewable and Low Carbon Fuel Requirements Regulation may materially adversely affect the Company's Prince George Refinery. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan are uncertain.

The application of the federal carbon policy in Manitoba may significantly adversely affect the Company's Minnedosa ethanol plant in Manitoba.

The Newfoundland and Labrador performance-based regulation imposes a carbon price beginning at $20/tonne in 2019 and escalating to $50/tonne in 2022. The provincial Gasoline and Diesel Tax begins at $20/tonne and will be adjusted with a goal of Atlantic parity related to provincial taxation (including carbon tax) of fuel products. The carbon tax rates will only increase to match equivalent increases in carbon taxation programs in neighbouring Atlantic provinces. There are noted exemptions for exploration drilling and aviation fuels. However, the addition of this carbon tax to marine diesel will increase operating costs for the Company's Atlantic region operation.

Within the mandate of the Pan-Canadian Framework on Clean Growth and Climate Change, in May 2017, the Government of Canada released a technical paper on the federal carbon policy introducing two key elements: a carbon levy applied to gas that the Company uses at its facilities as well as retail fuel ($20 per tonne starting in 2019 and increasing by $10 annually to $50 per tonne in 2022), and an output-based pricing system for industrial facilities emitting GHGs above 50,000 tonnes of CO_2e per year. In December 2018, the Government of Canada published the Regulatory Design Paper on the Clean Fuel Standard ("CFS") that focuses on the liquid fuel stream regulations. Draft CFS regulations are expected to be published in mid-2019 and final regulations in 2020, with the regulations expected to come into force in 2022. The impact of the CFS is still uncertain.

The Company's U.S. refining business may be materially adversely affected by the implementation of the Environmental Protection Agency's ("EPA") climate change rules or, by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products and by other U.S. climate change statutes at the federal or state level or by regulations imposed by other federal agencies or at the state or local level. Such legislation or regulations could require the Company's U.S. refining operations to significantly reduce emissions and/or purchase emission credits, thereby increasing operating and capital costs, and could change the demand for refined products which may have a material adverse effect on the Company's financial condition and results of operations.

The U.S. Renewable Fuel Standard ("RFS") program, through the EPA-specified renewable volume obligation ("RVO"), requires refiners to add annually increasing amounts of renewable fuels to their petroleum products or to purchase RINs in lieu of such blending. Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the "blend wall" (the 10 percent limit prescribed by most automobile warranties), the price and availability of RINs have been volatile.

The Company complies with the RFS program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. The Company cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. The Company's financial position and results of operations could be adversely affected if it is unable to pass the compliance costs on to its customers and if the Company pays significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards.

Competition

The energy industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production, and gaining access to markets. The Company competes with others to acquire prospective lands, retain drilling capacity and field operating and construction services, obtain sufficient pipeline and other transportation capacity, gain access to and retain adequate markets for its products and services and gain access to capital markets. The Company's ability to successfully complete development projects could be materially adversely affected if it is unable to acquire economic supplies and services due to competition. Subsequent increases in the cost of or delays in acquiring supplies and services could result in uneconomic projects. The Company's competitors comprise all types of energy companies, some of which have greater resources.

General Economic Conditions

General economic conditions may have a material adverse effect on the Company's results of operations and financial condition. A decline in economic activity will reduce demand for petroleum products and adversely affect the price the Company receives for its commodities. The Company's cash flow could decline, assets could be impaired, future access to capital could be restricted and major development projects could be delayed or abandoned.

Cost or Availability of Oil and Gas Field Equipment

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices. Without compromising safety, overall quality and environmental impacts, the Company continually develops its approved suppliers base to provide undisrupted access to materials, equipment and services, while maintaining a competitive cost baseline via cost escalation mitigation strategies.

Climatic Conditions

Extreme climatic conditions may have material adverse effects on the Company's financial condition and results of operations. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, the Company's exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by extreme weather. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

The Company operates in some of the harshest environments in the world, including offshore Newfoundland and Labrador. Climate change may increase the frequency of severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of Newfoundland and Labrador may threaten Atlantic oil production facilities, cause damage to equipment and possible production disruptions, spills, other asset damage and human impacts. The Company has in place a number of policies to protect people, equipment and the environment in the event of extreme weather conditions and ice melt conditions.

The Company's Atlantic operations have a robust ice management program, which uses a range of resources including a dedicated ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the risk has abated. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required. The Company regularly assesses all aspects of its ice management program in order to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs in the Atlantic becomes available and as new technologies are developed. The Company continues to look at ways to improve its ability to predict and respond to sea ice and icebergs with ongoing research and development. Recent initiatives include the design and fabrication of modular, heavy weather nets with sensors and development of a Common Operating Picture on Husky's contracted geographic information systems software module including ice flight information, location, drift models, and pack ice drift model runs. The Company now has a dedicated ice management room onshore, which mirrors the offshore and allows for real-time monitoring of field operations. Additional research and development activity related to ice management is continuing.

Financial Controls

While the Company has determined that its disclosure controls and procedures and internal controls over financial reporting are effective, such controls can only provide reasonable assurance with respect to financial statement preparation and disclosure. Failure to prevent, detect and correct misstatements could have a material adverse effect on the Company's results of operations and financial condition.

Cybersecurity Threats

As an oil and gas producer, the Company's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the financial and general operating aspects of the business. Concurrently, the oil and gas industry has become the subject of increased levels of cybersecurity threats.

The Company has security measures, policies and controls designed to protect and secure the integrity of its information technology systems. The Company takes a proactive approach by continuing to invest in technology, processes and people to help minimize the impact of the changing cyber landscape and enhance the Company's resilience to cyber incidents. However, cybersecurity threats frequently change and require ongoing monitoring and detection capabilities. Such cybersecurity threats include unauthorized access to information technology systems due to hacking, viruses and other causes for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. Cyber-attacks could result in the loss or exposure of confidential information related to retail credit card information, personnel files, exploration activities, corporate actions, executive officer communications and financial results. The significance of any such event is difficult to quantify, but if the breach is material in nature, it could adversely affect the financial performance of the Company, its operations, its reputation and standing and expose it to regulatory consequences and claims of third-party damage, all of which could materially adversely affect the Company's results of operations and financial condition if the situation is not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies.

Although to date the Company has not experienced any material losses relating to cyber attacks or other information security breaches, there can be no assurance that the Company will not incur such losses in the future. The Company's risk and exposure to these matters cannot be fully mitigated because of, among other things, the evolving nature of these threats. The Audit Committee of the Company's Board of Directors has oversight of the Company's risk mitigation strategies related to cybersecurity.

Skilled Workforce Attraction and Retention

Successful execution of the Company's strategy is dependent on ensuring the Company's workforce possesses the appropriate skill level. There is a risk that the Company may have difficulty attracting and retaining personnel with the required skill levels. Failure to attract and retain personnel with the required skill levels could have a material adverse effect on the Company's financial condition and results of operations.

Aviation Incidents

The Company's Offshore operations in Canada and China rely on regular travel by helicopter. A helicopter incident resulting in loss of life, facility shutdown or regulatory action could have a material adverse effect on the operations of the Company. This risk is managed through an aviation management process. Aviation Safety Reviews are conducted by third party specialist contractors to verify that helicopter service providers meet Husky and industry standards with respect to aviation safety. The reviews include evaluation of aircraft type, effectiveness of the safety and maintenance management systems and competency and training programs for critical roles in the operation of helicopters. Helicopters chartered to support Husky Offshore operations must be fit for service and as such are fitted with multiple redundant systems to address a wide range of potential in-flight emergencies. Additional measures specific to the Company's challenging operating environments are specified in the Company's design requirements including anti-icing and floatation systems effective for the maximum allowable sea height operating limits. Pilots are trained to address potential emergency situations through regular real-time and simulator training aligned with industry best practice.

Foreign Currency

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollars. The majority of the Company's expenditures are in Canadian dollars while most of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in the Company's U.S. dollar-denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollar denominated revenue to hedge against these potential fluctuations. The Company also designates its U.S. denominated debt as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

Interest Rate

Interest rate risk is the impact of fluctuating interest rates on financial condition. In order to manage interest rate risk and the resulting interest expense, the Company mitigates some of its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of its credit facilities and various financial instruments. The optimal mix maintained will depend on market conditions. The Company may also enter into interest rate swaps from time to time as an additional means of managing current and future interest rate risk.

On December 4, 2018, the Company entered into cash flow hedges using forward interest rate swaps to fix the underlying U.S. $500 million 10-year note fixed rate to December 15, 2019.

Counterparty Credit

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties in a transaction fail to meet or discharge their obligation to the Company. The Company actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies govern the Company's credit portfolio and limit transactions according to a counterparty's and a supplier's credit quality. Counterparties for financial derivatives transacted by the Company are generally major financial institutions or counterparties with investment grade credit ratings.

Liquidity

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's process for managing liquidity risk includes ensuring, to the extent possible, that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and capacity to raise capital from various debt and equity capital markets under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions at the time of sale.

Credit Rating Risk

Credit ratings affect the Company's ability to obtain both short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook could materially adversely affect the Company's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to the Company's securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

The Company is committed to retaining investment grade credit ratings to support access to capital markets and currently has the following credit ratings:

	Standard and Poor's Rating Services ("S&P")	Moody's Investor Service ("Moody's")	Dominion Bond Rating Services Limited ("DBRS")
Outlook/Trend	Stable	Stable	Stable
Senior Unsecured Debt	BBB	Baa2	A(low)
Series 1 Preferred Shares	P-3(high)		Pfd-2(low)
Series 2 Preferred Shares	P-3(high)		Pfd-2(low)
Series 3 Preferred Shares	P-3(high)		Pfd-2(low)
Series 5 Preferred Shares	P-3(high)		Pfd-2(low)
Series 7 Preferred Shares	P-3(high)		Pfd-2(low)
Commercial Paper			R-1(low)

Debt Covenants

The Company's credit facilities include financial covenants, which contain a debt to capital covenant. If the Company does not comply with the covenants under these credit facilities, there is a risk that repayment could be accelerated.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

Cash Flow Summary ($ millions)	2018	2017
Cash flow		
Operating activities	**4,134**	3,704
Financing activities	**(325)**	363
Investing activities	**(3,521)**	(2,789)

Cash Flow from Operating Activities

Cash flow generated from operating activities increased by $430 million in 2018 compared to 2017. The increase was primarily due to an increase from the Company's Infrastructure and Marketing segment, higher realized prices for synthetic crude oil combined with decreased average cost of crude oil feedstock in the Company's upgrading operations, and increased production from the Company's Asia Pacific operations.

Cash Flow from (used for) Financing Activities

Cash flow used for financing activities increased by $688 million in 2018 compared to 2017. Financing activities in 2018 related primarily to the reinstatement of the quarterly cash dividend in 2018. Financing activities in 2017 related primarily to the net issuance of long-term debt.

Cash Flow used for Investing Activities

Cash flow used for investing activities increased by $732 million in 2018 compared to 2017. The increase was primarily due to increased capital expenditures in 2018.

6.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2018, the Company's working capital was $694 million compared to $2,109 million at December 31, 2017. A reconciliation of the Company's working capital is as follows:

Working Capital ($ millions)	December 31, 2018	December 31, 2017	Change
Cash and cash equivalents	**2,866**	2,513	353
Accounts receivable	**1,355**	1,186	169
Income taxes receivable	**112**	164	(52)
Inventories	**1,232**	1,513	(281)
Prepaid expenses	**123**	145	(22)
Restricted cash	**—**	95	(95)
Accounts payable and accrued liabilities	**(3,159)**	(3,033)	(126)
Short-term debt	**(200)**	(200)	—
Long-term debt due within one year	**(1,433)**	—	(1,433)
Asset retirement obligations	**(202)**	(274)	72
Net working capital	**694**	2,109	(1,415)

The increase in cash and cash equivalents was primarily due to the higher global commodity prices for the majority of 2018. Fluctuations in accounts receivable and accounts payable were due to the timing of settlements in 2018 compared to 2017. The decrease in income taxes receivable was primarily due to the timing of expected tax refunds. The decrease in inventories was primarily driven by decreased market values in the fourth quarter of 2018. The decrease in restricted cash was primarily due to the expiry of the Company's participation in the Wenchang oilfield PSC in late 2017. The increase in long-term debt due within one year was due to the timing of debt maturities.

6.3 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include funds from operations, proceeds from the issuance of equity, proceeds from the issuance of short and long-term debt, availability of short and long-term credit facilities and proceeds from asset sales. Since the Company operates in the upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt.

During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. The Company believes that it has sufficient liquidity to sustain its operations, fund capital programs and meet non-cancellable contractual obligations and commitments in the short and long-term principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of debt, borrowings under committed and uncommitted credit facilities and cash proceeds from asset sales. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

At December 31, 2018, the Company had the following available credit facilities:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities[1]	**900**	**461**
Syndicated credit facilities[2]	**4,000**	**3,800**
	4,900	**4,261**

(1) *Consists of demand credit facilities.*
(2) *Commercial paper outstanding is supported by the Company's syndicated credit facilities.*

At December 31, 2018, the Company had $4,261 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $461 million are short-term uncommitted credit facilities. A total of $439 million short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2018, the Company had no direct borrowing against committed credit facilities. The maturity dates for the Company's revolving syndicated credit facilities are March 9, 2020 and June 19, 2022. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade credit rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

The Company's share capital is not subject to external restrictions. The Company's leverage covenant under both of its revolving syndicated credit facilities is debt to capital and calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2018, and assessed the risk of non-compliance to be low.

Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at December 31, 2018.

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019. The 2017 Canadian Shelf Prospectus replaced the Company's Canadian universal short form base shelf prospectus which expired on March 23, 2017. During the 25-month period that the 2017 Canadian Shelf Prospectus is in effect, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.

On January 29, 2018, the Company filed a universal short form base shelf prospectus ("the 2018 U.S. Shelf Prospectus") with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement filed with the Securities and Exchange Commission ("SEC") containing the 2018 U.S. Shelf Prospectus became effective which enables the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. up to and including February 29, 2020. The 2018 U.S. Shelf Prospectus replaced the Company's U.S. universal short form base shelf prospectus which expired on January 22, 2018. During the 25-month period that the 2018 U.S. Shelf Prospectus and the related U.S. registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

As at December 31, 2018, the Company has $3.0 billion in unused capacity under the 2017 Canadian Shelf Prospectus and US$3.0 billion in unused capacity under the 2018 U.S. Shelf Prospectus and related U.S. registration statement. The ability of the Company to utilize the capacity under the 2017 Canadian Shelf Prospectus and 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net Debt

Net debt, a non-GAAP measure (see Section 9.3), is calculated as total debt less cash and cash equivalents. The Company had total debt of $5,747 million and cash and cash equivalents of $2,866 million at December 31, 2018, compared to total debt of $5,440 million and cash and cash equivalents of $2,513 million at December 31, 2017. The Company's net debt at December 31, 2018 decreased by $46 million when compared to December 31, 2017:

Net Debt[(1)] *($ millions)*	**December 31, 2018**	December 31, 2017
Net debt at beginning of period	**(2,927)**	(4,020)
Change in net debt due to:		
Funds from operations[(1)]	**4,004**	3,306
Capital expenditures	**(3,578)**	(2,220)
Capitalized interest	**(108)**	(68)
Corporate acquisition	**(15)**	(670)
Dividends on preferred shares	**(35)**	(34)
Dividends on common shares	**(402)**	—
Change in non-cash working capital	**485**	638
Proceeds from asset sales	**4**	192
Effect of exchange rates on cash and cash equivalents	**65**	(84)
Effect of exchange rates on long-term debt	**(307)**	284
Contribution payable payment	**—**	(142)
Contributions to joint ventures	**(40)**	(81)
Other	**(27)**	(28)
	46	1,093
Net debt at end of period	**(2,881)**	(2,927)

(1) *Net debt and funds from operations are non-GAAP measures. Refer to Section 9.3 for reconciliations to the corresponding GAAP measures.*

During the years ended December 31, 2018 and 2017, the Company's capital expenditures were funded by funds from operations. The Company's funds from operations are dependent on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. Management prepares capital expenditure budgets annually which are regularly monitored and updated to adapt to changes in market factors. In addition, the Company requires authorizations for capital expenditures on projects, which assists with the management of capital.

On February 28, 2018, the Board of Directors reinstated the quarterly common share cash dividend of $0.075 per share. On July 26, 2018, the quarterly common share cash dividend was increased to $0.125 per share.

6.4 Capital Structure

Capital Structure ($ millions)	December 31, 2018 Outstanding
Total debt[1]	5,747
Shareholders' equity	19,614

(1) Total debt is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt, which was $25.4 billion at December 31, 2018 (December 31, 2017 – $23.4 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations (refer to Section 9.3). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At December 31, 2018, debt to capital employed was 22.7 percent (December 31, 2017 – 23.2 percent) and debt to funds from operations was 1.4 times (December 31, 2017 – 1.6 times), within the Company's targets.

To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

6.5 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

In the normal course of business, the Company is obligated to make future payments. The following summarizes known non-cancellable contracts and other commercial commitments:

Contractual Obligations

Payments due by period ($ millions)	2019	2020-2021	2022-2023	Thereafter	Total
Long-term debt and interest on fixed rate debt	1,697	724	956	3,709	7,086
Operating leases[1]	233	245	259	1,186	1,923
Firm transportation agreements[1]	497	1,036	1,030	4,013	6,576
Unconditional purchase obligations[2]	1,620	2,447	1,209	4,822	10,098
Lease rentals and exploration work agreements	49	123	123	930	1,225
Obligations to fund equity investee[3]	53	147	146	395	741
Finance lease obligations[4]	69	138	104	1,014	1,325
Asset retirement obligations[5]	202	293	287	8,541	9,323
	4,420	5,153	4,114	24,610	38,297

(1) *Included in the total of operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of $1.1 billion and $1.9 billion respectively with HMLP.*

(2) *Includes processing services, distribution services, insurance premiums, drilling services, natural gas purchases and the purchase of refined petroleum products.*

(3) *Equity investee refers to the Company's investment in Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

(4) *Refer to Note 17 in the 2018 consolidated financial statements.*

(5) *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets. The amounts are inclusive of $128 million of cash deposited into restricted accounts for funding of future asset retirement obligations in Asia Pacific and obligations related to Husky's working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.*

Other Obligations

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that decisions in any pending or threatened proceedings related to these and other matters, or any amount which it may be required to pay, would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time. Management believes that it has adequately provided for current and deferred income taxes.

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds into separate accounts restricted to the funding of future asset retirement obligations in offshore China. As at December 31, 2018, the Company has deposited funds of $128 million, which has been reclassified as non-current.

The Company is also subject to various contingent obligations that become payable only if certain events or rulings occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess their impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

The Company has a number of contingent environmental liabilities, which individually have been estimated to be immaterial. These contingent environmental liabilities are primarily related to the migration of contamination at fuel outlets and certain legacy sites where the Company had previously conducted operations. The contingent environmental liabilities involved have been considered in aggregate and based on reasonable estimates the Company does not believe they will result, in aggregate, in a material adverse effect on its financial position, results of operations or liquidity.

Off-Balance Sheet Arrangements

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

Standby Letters of Credit

On occasion, the Company issues letters of credit in connection with transactions in which the counterparty requires such security.

6.6 Transactions with Related Parties

The Company performs management services as the operator of the assets held by HMLP for which it recovers shared service costs. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to Power Assets Holdings Limited and CK Infrastructure Holdings Limited, which are affiliates of one of the Company's principal shareholders. For the year ended December 31, 2018, the Company charged HMLP $448 million related to construction costs and management services. For the year ended December 31, 2018, the Company had purchases from HMLP of $200 million related to the use of the pipeline for the Company's blending, transportation and storage activities. As at December 31, 2018, the Company had $140 million due from HMLP.

6.7 Outstanding Share Data

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 21, 2019

• common shares	1,005,121,738
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	19,934,692
• stock options exercisable	10,443,916

7.0 Critical Accounting Estimates and Key Judgments

The Company's consolidated financial statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Significant accounting policies are disclosed in Note 3 to the 2018 consolidated financial statements. Certain of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

7.1 Accounting Estimates

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained, and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization and impairment, recoveries from insurance claims, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes and reserves and contingencies are based on estimates.

Depletion, Depreciation, Amortization and Impairment

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. The aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved developed reserves using the unit of production method, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied.

Impairment and Reversals of Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment or reversal of impairment. Determining whether there are any indications of impairment, or reversal of impairment, requires significant judgment of external factors, such as an extended change in prices or margins for oil and gas commodities or products, a significant change in an asset's market value, a significant change and revision of estimated volumes, revision of future development costs, a change in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an adverse impact on the entity. If impairment, or reversal of impairments, is indicated the amount by which the carrying value is different from the estimated recoverable amount of the long-lived asset is charged to net earnings.

The determination of the recoverable amount for impairment, or reversal of impairment, involves the use of numerous assumptions and estimates. Estimates of future cash flows used in the evaluation of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, marketing supply and demand, forecasted crack spreads, growth rate, discount rate and, in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and probable volumes and where applicable economically recoverable resources associated with interests in certain Husky properties which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate. Future revisions to these assumptions impact the recoverable amount.

Impairment losses recognized for assets in prior years are assessed at the end of each reporting period for indications that the impairment has decreased or no longer exists. An impairment loss is reversed only to the extent that the carrying amount of the asset or cash generating units ("CGUs") does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Asset Retirement Obligations

Estimating asset retirement obligations requires that the Company estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations. Inherent in the calculation of asset retirement obligations are numerous assumptions and estimates, including the ultimate settlement amounts, future third-party pricing, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in changes to the asset retirement obligations.

Fair Value of Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, derivatives, portions of other assets and other long-term liabilities. Derivative instruments are measured at fair value through profit or loss. The Company's remaining financial instruments are measured at amortized cost. For financial instruments measured at amortized cost, the carrying values approximate their fair value with the exception of long-term debt.

The Company's financial assets and liabilities that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy. Level 1 fair value measurements are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair value measurements of assets and liabilities in Level 2 include valuations using inputs other than quoted prices but for which all significant outputs are observable, either directly or indirectly. Level 3 fair value measurements are based on inputs that are unobservable and significant to the overall fair value measurement.

The fair values of derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future result.

Employee Future Benefits

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of estimates that affect expected future benefit payments. These estimates include, but are not limited to, attrition, mortality, the rate of return on pension plan assets, salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment, often after the passage of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can be reasonably estimated. When a loss is determined it is charged to net earnings. The Company must continually monitor known and potential contingent matters and make appropriate provisions by charges to net earnings when warranted by circumstances.

7.2 Key Judgments

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include determination of technical feasibility and commercial viability, impairment assessments, the determination of CGUs, changes in reserve estimates, the determination of a joint arrangement, the designation of the Company's functional currency and the fair value of related party transactions.

Exploration and Evaluation Costs

Costs directly associated with an exploration well are initially capitalized as exploration and evaluation assets. Expenditures related to wells that do not find reserves or where no future activity is planned are expensed as exploration and evaluation expenses. Exploration and evaluation costs are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed or production commences. At that time, costs are either transferred to property, plant and equipment or their value is impaired. Impairment is charged directly to net earnings. Drilling results, required operating costs and capital expenditure and estimated reserves are important judgments when making this determination and may change as new information becomes available.

Impairment of Financial Assets

A financial asset is assessed at the end of each reporting period to determine whether it is impaired based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates. Given that the calculations for the net present value of estimated future cash flows related to derivative financial assets require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

Cash Generating Units

The Company's assets are grouped into respective CGUs, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of the Company's CGUs is subject to management's judgment.

Reserves

Oil and gas reserves are evaluated internally and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments and reversal of impairments of property, plant and equipment.

Net reserves represent the Company's undivided gross working interest in total reserves after deducting crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as applicable, as at the balance sheet date and could differ significantly from other points in time throughout the year or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Joint Arrangements

Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

Classification of a joint arrangement as either joint operation or joint venture requires judgment. Management's considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

Functional and Presentation Currency

Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The designation of the Company's functional currency is a management judgment based on the composition of revenues and costs in the locations in which it operates.

Related Party Judgments and Estimates

The Company entered into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. These transactions are on terms equivalent to those that prevail in arm's-length transactions. Proceeds for disposition of assets to related parties are recognized at fair value, based on discounted cash flow forecast from those assets. Independent opinions of the fair value may be obtained. Changes in the assumptions used to determine these fair values may result in a material difference in the proceeds and any gain or loss on disposition.

8.0 Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the consolidated statements of income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. Optional exemptions to not recognize certain short-term leases or leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged.

The Company will adopt IFRS 16 on the effective date of January 1, 2019 and has selected the modified retrospective transition approach. The optional exemptions to not recognize certain short-term and low value leases will be applied.

For leases implemented January 1, 2019, the Company will recognize a right-of-use asset of $1.1 billion equal to the lease liability at the present value of the remaining lease payments discounted using the Company's incremental borrowing rate. The implementation of IFRS 16 does not have a material impact on the consolidated statements of income. Due to a change in classification of operating lease expenses, cash flow from operating activities will increase and cash flow from financing activities will decrease, with no overall impact to the cash position for the Company.

Change in Accounting Policy

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15 Revenue from Contracts with Customers, deferring the effective date to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 15 did not require any material adjustments to the amounts recorded in the consolidated financial statements; however, additional disclosures are presented in the consolidated financial statements.

Revenue is recognized when the performance obligations are satisfied and revenue can be reliably measured. Revenue is measured at the consideration specified in the contracts and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Natural gas sales in Asia Pacific are under long-term, fixed price contracts. Substantially all other revenue is based on floating prices. Performance obligations associated with the sale of crude oil, crude oil equivalents, and refined products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with processing services, transportation, blending and storage, and marketing services are satisfied at the point in time when the services are provided.

Financial Instruments

In July 2014, the IASB issued IFRS 9 Financial Instruments to replace IAS 39, which provides a single model for classification and measurement based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial instruments. For financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in a more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard was effective for annual periods beginning on January 1, 2018. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 9 did not require any material adjustments to the consolidated financial statements.

Financial assets previously classified as loans and receivables (cash and cash equivalents, accounts receivable, restricted cash, and long-term receivables), as well as financial liabilities previously classified as other financial liabilities (accounts payable and accrued liabilities, short-term debt, and long-term debt) have been reclassified to amortized cost. The carrying value and measurement of all financial instruments remains unchanged. The Company's current process for assessing short-term receivables lifetime expected credit losses collectively in groups that share similar credit risk characteristics is unadjusted with the adoption of the new impairment model and resulted in no additional impairment allowance. Additionally, long-term receivables were assessed individually under the expected credit loss model and no impairment was concluded.

Amendments to IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018. The amendments clarify how to account for certain types of share-based payment arrangements. The adoption of the amendments did not have a material impact on the Company's consolidated financial statements.

9.0 Reader Advisories

9.1 Forward-Looking Statements

Certain statements in this document are forward-looking statements and information (collectively, "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "is estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; the Company's 2019 production guidance, including guidance for specified areas and product types; the Company's objective of maintaining stated debt to funds from operations and debt to capital employed ratio targets; and the Company's 2019 Upstream capital expenditure program;
- with respect to the Company's thermal developments: estimated production and expected timing of first production from the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central, Dee Valley 2 and Westhazel projects; the expected timing of regulatory approvals for the Dee Valley 2 and Westhazel projects; and the expected impact of the Alberta government-mandated production curtailment on the Tucker Thermal Project and the Sunrise Energy Project;
- with respect to the Company's non-thermal developments, the expected impact of the Alberta government-mandated production curtailment;
- with respect to the Company's Western Canada resource plays, strategic and drilling plans;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of drilling of the remaining three wells at, and first gas production from, Liuhua 29-1; target production from Liuhua 29-1 when fully ramped up; the expected timing of drilling five MDA field production wells and two MBH field production wells, and the expected timing of first gas production and sales therefrom; timing for a second exploration well on Block 16/25; and the expected timing of development and tie-in of the additional MDK shallow water field;
- with respect to the Company's Offshore business in the Atlantic: the expected timing of first production from the West White Rose Project; the expected timing that two additional infill wells will be completed and come online at the White Rose field; and delineation plans at the A-24 exploration well;
- with respect to the Company's Infrastructure and Marketing business, the processing capacity expected to be added by the Ansell Corser Gas Plant when it comes online, and the expected timing thereof; and
- with respect to the Company's Downstream operating segment: plans to market and potentially sell the Prince George Refinery and the Retail and Commercial Network; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; and the expected timing that operations at the Superior Refinery will resume.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserves and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events, including the timing of regulatory approvals, that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers and regulators, among others.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company's Annual Information Form for the year ended December 31, 2018 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

9.2 Oil and Gas Reserves Reporting

Disclosure of Oil and Gas Reserves and Other Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, has been audited and reviewed by Sproule, an independent qualified reserves auditor, have an effective date of December 31, 2018 and represent the Company's working interest share (ii) projected and historical production volumes quoted are gross, which represents the total or the Company's working interest, as applicable share before deduction of royalties (iii) all Husky working interest production volumes quoted are before deduction of royalties; and (iv) historical production volumes provided are for the year ended December 31, 2018.

The Company uses the term barrels of oil equivalent ("boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies but does not represent value equivalency at the wellhead.

The Company uses the term reserves replacement ratio, which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserves additions for that period divided by the Company's Upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserve base during a given period. Reserves replacement ratios that exclude economic factors will exclude the impacts that changing oil and gas prices have.

This document includes an estimate of net pay thickness at White Rose A-24, which estimate may be considered to be anticipated results under NI 51-101. The estimate was prepared internally. The risks and uncertainties associated with recovery of resources from A-24 include, but are not limited to: that Husky may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves.

Note to U.S. Readers

The Company reports its reserves information in accordance with Canadian practices and specifically in accordance with NI 51-101. Because the Company is permitted to prepare its reserves information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.

9.3 Non-GAAP Measures

Disclosure of non-GAAP Measures

The Company uses measures primarily based on IFRS and also uses some secondary non-GAAP measures. The non-GAAP measures included in this MD&A and related disclosures are: funds from operations, free cash flow, total debt, net debt, operating netback, debt to capital employed, debt to funds from operations and LIFO. None of these measures is used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for operating netback, debt to capital employed or debt to funds from operations. These are useful complementary measures that are used by management in assessing the Company's financial performance, efficiency and liquidity, and they may be used by the Company's investors for the same purpose. The non-GAAP measures do not have standardized meanings prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP measures are defined below.

Debt to Capital Employed

Debt to capital employed percentage is a non-GAAP measure and is equal to total debt divided by capital employed. Capital employed is equal to total debt and shareholders' equity. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

Debt to Funds from Operations

Debt to funds from operations is a non-GAAP measure and is equal to total debt divided by funds from operations. Funds from operations is equal to cash flow – operating activities plus change in non-cash working capital. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of debt to funds from operations for the periods ended December 31, 2018, 2017 and 2016:

Debt to Funds from Operations *($ millions)*	**December 31, 2018**	December 31, 2017	December 31, 2016
Total debt	**5,747**	5,440	5,339
Funds from operations	**4,004**	3,306	2,198
Debt to funds from operations	**1.4**	1.6	2.4

Funds from Operations and Free Cash Flow

Funds from operations is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations equals cash flow – operating activities plus change in non-cash working capital. Management believes that impacts of non-cash working capital items on cash flow – operating activities may reduce comparability between periods, accordingly, funds from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance of the Company in the stated period compared to prior periods.

Funds from operations was restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

Free cash flow is a non-GAAP measure, which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Free cash flow is presented to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures.

Free cash flow has been restated in the fourth quarter of 2018 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of investment in joint ventures. Prior periods have been restated to conform to current presentation.

The following table shows the reconciliation of net earnings to funds from operations and free cash flow, and related per share amounts for the three months and years ended December 31:

Reconciliation of Cash Flow	Three months ended		Year ended		
	Dec. 31	Dec. 31	**Dec. 31**	Dec. 31	Dec. 31
($ millions)	**2018**	2017	**2018**	2017	2016
Net earnings	**216**	672	**1,457**	786	922
Items not affecting cash:					
Accretion	**25**	28	**97**	112	126
Depletion, depreciation, amortization and impairment	**662**	647	**2,591**	2,882	2,462
Inventory write-down to net realizable value	**60**	—	**60**	—	9
Exploration and evaluation expenses	**22**	—	**29**	6	86
Deferred income taxes (recoveries)	**25**	(360)	**396**	(359)	29
Foreign exchange loss (gain)	**1**	1	**(6)**	(4)	(4)
Stock-based compensation	**(50)**	25	**44**	45	33
Gain on sale of assets	**—**	(13)	**(4)**	(46)	(1,634)
Unrealized market to market loss (gain)	**(16)**	57	**(150)**	56	38
Share of equity investment gain	**(16)**	(1)	**(69)**	(61)	(15)
Gain on insurance recoveries for damage to property	**(253)**	—	**(253)**	—	—
Other	**2**	8	**21**	16	24
Settlement of asset retirement obligations	**(65)**	(45)	**(181)**	(136)	(87)
Deferred revenue	**(30)**	(5)	**(100)**	(16)	209
Distribution from joint ventures	**—**	—	**72**	25	—
Change in non-cash working capital	**730**	337	**130**	398	(227)
Cash flow – operating activities	**1,313**	1,351	**4,134**	3,704	1,971
Change in non-cash working capital	**(730)**	(337)	**(130)**	(398)	227
Funds from operations	**583**	1,014	**4,004**	3,306	2,198
Capital expenditures	**(1,265)**	(745)	**(3,578)**	(2,220)	(1,705)
Free Cash Flow	**(682)**	269	**426**	1,086	493
Funds from operations – basic	**0.58**	1.01	**3.98**	3.29	2.19
Funds from operations – diluted	**0.58**	1.01	**3.98**	3.29	2.19

LIFO

The Chicago 3:2:1 market crack spread benchmark is based on LIFO inventory costing, a non-GAAP measure, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis, the comparable GAAP measure, crude oil feedstock costs included in realized margins reflect purchases made in previous months. Management believes that comparisons between LIFO and FIFO inventory costing assist management and investors in assessing differences in the Company's realized refining margins compared to the Chicago 3:2:1 market crack spread benchmark, which is commonly used by the Company's U.S. refining peers.

Net Debt

Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of total debt to net debt as at December 31, 2018, 2017 and 2016:

Net Debt *($ millions)*	**December 31, 2018**	December 31, 2017	December 31, 2016
Total debt	**5,747**	5,440	5,339
Cash and cash equivalents	**(2,866)**	(2,513)	(1,319)
Net debt	**2,881**	2,927	4,020

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. Management believes this measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

Total debt

Total debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of total debt as at December 31, 2018, 2017 and 2016:

Total Debt *($ millions)*	**December 31, 2018**	December 31, 2017	December 31, 2016
Short-term debt	**200**	200	200
Long-term debt due within one year	**1,433**	—	403
Long-term debt	**4,114**	5,240	4,736
Total debt	**5,747**	5,440	5,339

9.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis

This Management's Discussion and Analysis is intended to provide an explanation of financial and operational performance compared with prior periods and the Company's prospects and plans. It provides additional information that is not contained in the Company's consolidated financial statements.

Review by the Audit Committee

This Management's Discussion and Analysis was reviewed by the Company's Audit Committee and approved by the Board of Directors on February 25, 2019. Any events subsequent to that date could materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This Management's Discussion and Analysis dated February 25, 2019, should be read in conjunction with the 2018 consolidated financial statements and related notes. Readers are also encouraged to refer to the Company's interim reports filed for 2018, which contain Management's Discussion and Analysis and consolidated financial statements, and the Company's Annual Information Form for the year ended December 31, 2018, filed separately with Canadian securities regulatory authorities, and annual Form 40-F filed with the SEC, the U.S. federal securities regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com. Husky's Management's Discussion and Analysis for the interim period ended December 31, 2018 is incorporated herein by reference.

Use of Pronouns and Other Terms

"Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2018 and 2017 and the Company's financial position at December 31, 2018 and 2017.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change his or her decision to buy, sell or hold Husky's securities.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with IFRS as issued by the IASB.
- All dollar amounts are in Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represents the Company's working interest share before royalties.
- Prices are presented before the effect of hedging.

Terms

Asia Pacific	*Includes Upstream oil and gas exploration and production activities located offshore China and Indonesia*
Atlantic	*Includes Upstream oil and gas exploration and production activities located offshore Newfoundland and Labrador*
Bitumen	*Bitumen is a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Debt to capital employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to funds from operations	*Long-term debt, long-term debt due within one year and short-term debt divided by funds from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate transmissibility of the oil through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Free Cash Flow	*Funds from operations less capital expenditures*
Funds from operations	*Cash flow - operating activities plus change in non-cash working capital*
Gross/net wells	*Gross refers to the total number of wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross reserves/production	*A company's working interest share of reserves/production before deduction of royalties*
Heavy crude oil	*Crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity*
high-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as high-TAN crudes*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net debt	*Total debt less cash and cash equivalents*
Net revenue	*Gross revenues less royalties*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Oil sands	*Sands and other rock materials that contain crude bitumen and include all other mineral substances in association therewith*
Operating netback	*Gross revenue less royalties, operating costs and transportation costs on a per unit basis*
Plan of Development	*As it relates to the Company's operations in Indonesia, a Plan of Development represents development planning on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves considering technical, economical and environmental aspects. An initial Plan of Development in a development area needs both SKK Migas and the Minister of Energy and Mineral Resources approvals. Subsequent Plans of Development in the same development area only need SKK Migas approval*
Probable reserves	*Those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves*

Proved developed reserves	*Those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing*
Proved reserves	*Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves*
Seismic survey	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' equity	*Common shares, preferred shares, contributed surplus, retained earnings, accumulated other comprehensive income and non-controlling interest*
Stratigraphic test well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Thermal	*Use of steam injection into the reservoir in order to enable heavy oil and bitumen to flow to the well bore.*
Total debt	*Long-term debt including long-term debt due within one year and short-term debt*
Turnaround	*Performance of scheduled plant or facility maintenance requiring the complete or partial shutdown of the plant or facility operations*
Western Canada	*Includes Upstream oil and gas exploration and development activities located in Alberta, Saskatchewan and British Columbia*

Units of Measure

bbls	*barrels*	*mboe*	*thousand barrels of oil equivalent*
bbls/day	*barrels per day*	*mboe/day*	*thousand barrels of oil equivalent per day*
bcf	*billion cubic feet*	*mcf*	*thousand cubic feet*
boe	*barrels of oil equivalent*	*mcfge*	*million cubic feet of gas equivalent*
boe/day	*barrels of oil equivalent per day*	*mmbbls*	*million barrels*
CO_2e	*carbon dioxide equivalent*	*mmboe*	*million barrels of oil equivalent*
GJ	*gigajoule*	*mmbtu*	*million British Thermal Units*
mbbls	*thousand barrels*	*mmcf*	*million cubic feet*
mbbls/day	*thousand barrels per day*	*mmcf/day*	*million cubic feet per day*

9.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, under supervision of the Chief Executive Officer and the Chief Financial Officer, have evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2018, and have concluded that such disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management, under the supervision of the Chief Executive Officer and Chief Financial Officer, is responsible for designing, establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission (2013) framework to evaluate the effectiveness of Husky's internal control over financial reporting.

3) As at December 31, 2018, management, under the supervision of the Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective.

4) KPMG LLP, who has audited the consolidated financial statements of Husky for the year ended December 31, 2018, has also issued a report on internal controls over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States) that attests to Husky's internal controls over financial reporting.

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2018, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

10.0 Selected Quarterly Financial and Operating Information

10.1 Summary of Quarterly Results

Fourth Quarter Results Summary *($ millions, except where indicated)*	Three months ended **Dec. 31 2018**	 Dec. 31 2017
Gross revenues and Marketing and other		
Upstream		
Exploration and Production	**643**	1,355
Infrastructure and Marketing	**678**	633
Downstream		
Upgrading	**307**	452
Canadian Refined Products	**821**	815
U.S. Refining and Marketing	**2,766**	2,755
Corporate and Eliminations	**(173)**	(476)
Total gross revenues and marketing and other	**5,042**	5,534
Net earnings (loss)		
Upstream		
Exploration and Production	**(206)**	170
Infrastructure and Marketing	**126**	(27)
Downstream		
Upgrading	**80**	48
Canadian Refined Products	**55**	39
U.S. Refining and Marketing	**213**	129
Corporate and Eliminations	**(52)**	313
Net earnings	**216**	672
Per share – Basic	**0.21**	0.66
Per share – Diluted	**0.16**	0.66
Cash flow – operating activities	**1,313**	1,351
Funds from operations[(1)]	**583**	1,014
Per share – Basic	**0.58**	1.01
Per share – Diluted	**0.58**	1.01
Upstream		
Daily gross production		
Crude oil and NGL production *(mbbls/day)*[(2)]	**214.7**	231.2
Natural gas production *(mmcf/day)*[(2)]	**537.6**	534.9
Total production *(mboe/day)*	**304.3**	320.4
Average sales prices realized *($/boe)*		
Crude oil and NGL *($/bbl)*[(2)]	**18.93**	51.06
Natural gas *($/mcf)*[(2)]	**6.86**	5.89
Total average sales prices realized *($/boe)*	**25.47**	46.69
Downstream		
Refinery throughput		
Lloydminster Upgrader *(mbbls/day)*	**71.8**	78.2
Lloydminster Refinery *(mbbls/day)*	**25.3**	30.1
Prince George Refinery *(mbbls/day)*	**10.7**	11.3
Lima Refinery *(mbbls/day)*	**105.9**	164.5
BP-Husky Toledo Refinery *(mbbls/day)*	**73.2**	81.0
Superior Refinery *(mbbls/day)*	**—**	22.0
Total throughput *(mbbls/day)*	**286.9**	387.1

Fourth Quarter Results Summary (continued)	Three months ended Dec. 31	
($ millions, except where indicated)	**Dec. 31 2018**	Dec. 31 2017
Upgrading unit margin *($/bbl)*	**29.13**	20.65
Upgrading synthetic crude oil sales *(mbbls/day)*	**53.8**	56.5
Upgrading total sales *(mbbls/day)*	**73.5**	77.9
Retail fuel sales *(million of litres/day)*	**8.0**	8.0
Canadian light oil margins *($/litre)*	**0.037**	0.052
Lloydminster Refinery asphalt margin *($/bbl)*	**41.50**	15.79
U.S. Refining and Marketing margin *(US$/bbl crude throughput)*(3)	**9.12**	14.89
U.S./Canadian dollar exchange rate *(US$)*	**0.757**	0.786

(1) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*
(2) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*
(3) *Prior period has been restated to include impact of U.S. product marketing margin.*

Gross Revenue and Marketing and Other

The Company's consolidated gross revenues and marketing and other decreased by $492 million in the fourth quarter of 2018 compared to the fourth quarter of 2017.

In the Upstream business segment, Exploration and Production gross revenues decreased primarily due to lower average realized sales prices combined with lower production. Infrastructure and Marketing gross revenues and marketing and other increased primarily due to crude oil marketing gains from widening location price differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline.

In the Downstream business segment, gross revenues decreased primarily due to lower realized prices for synthetic crude oil in the Upgrading business segment.

Net Earnings (Loss)

The Company's consolidated net earnings decreased by $456 million in the fourth quarter of 2018 compared to the fourth quarter of 2017.

In the Upstream business segment, Exploration and Production net loss increased primarily due to the same factors which impacted gross revenue and marketing and other.

In the Downstream business segment, Upgrading net earnings increased primarily due to the widening of the light/heavy oil differentials. Canadian Refined Products and U.S. Refining and Marketing net earnings increased primarily due to lower average cost of crude oil feedstock and pre-tax insurance recoveries for property damage, rebuild costs and business interruption associated with the incident at the Superior Refinery in the fourth quarter of 2018 compared to the fourth quarter of 2017.

In the Corporate business segment, net loss increased primarily due to the recognition of a $436 million deferred tax recovery in 2017, related to the reduction of the U.S. Federal corporate tax rate that took effect at the beginning of 2018.

Cash Flow – Operating Activities and Funds from Operations

Cash flow – operating activities and funds from operations decreased by $38 million and $431 million, respectively, in the fourth quarter of 2018 compared to the fourth quarter of 2017, primarily due to the same factors which impacted the Upstream and Downstream business segment net earnings, excluding the pre-tax insurance recoveries for rebuild costs associated with the incident at the Superior Refinery. Funds from operations is a non-GAAP measure; refer to Section 9.3.

Daily Gross Production

Production decreased by 16.1 mbbls/day during the fourth quarter of 2018 compared to the fourth quarter of 2017 as a result of:

- Decreased crude oil production in Atlantic due to the suspension of operations on the *SeaRose* FPSO vessel;
- Decreased heavy crude oil production due to natural declines and reduced optimization activities in the Company's non-thermal developments;
- Decreased crude oil production in Asia Pacific due to the expiry of the Company's participation in the Wenchang oilfield PSC in late 2017; and
- Decreased crude oil and natural gas production in Western Canada as a result of the disposition of select legacy assets in 2017.

Partially offset by:

- Increased bitumen production from the Company's thermal projects;
- Increased natural gas and NGL production from the Liwan Gas and BD projects; and
- Increased NGL production in Western Canada.

Segmented Operational Information

Segmented Operational Information ($ millions, except where indicated)	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Gross revenues and Marketing and other								
Upstream								
Exploration and Production	**643**	**1,319**	**1,284**	**1,084**	1,355	1,157	1,215	1,251
Infrastructure and Marketing	**678**	**769**	**821**	**611**	633	509	425	369
Downstream								
Upgrading	**307**	**534**	**444**	**465**	452	377	227	384
Canadian Refined Products	**821**	**1,001**	**869**	**721**	815	802	602	568
U.S. Refining and Marketing[1]	**2,766**	**3,198**	**3,035**	**2,771**	2,755	2,292	2,135	2,173
Corporate and Eliminations	**(173)**	**(521)**	**(470)**	**(390)**	(476)	(424)	(253)	(397)
Total gross revenues and marketing and other	**5,042**	**6,300**	**5,983**	**5,262**	5,534	4,713	4,351	4,348
Net earnings (loss)								
Upstream								
Exploration and Production	**(206)**	**214**	**158**	**57**	170	28	(67)	43
Infrastructure and Marketing	**126**	**149**	**154**	**138**	(27)	10	33	70
Downstream								
Upgrading	**80**	**88**	**84**	**109**	48	9	5	48
Canadian Refined Products	**55**	**43**	**32**	**28**	39	38	12	15
U.S. Refining and Marketing	**213**	**158**	**115**	**(5)**	129	114	12	(21)
Corporate and Eliminations	**(52)**	**(107)**	**(95)**	**(79)**	313	(63)	(88)	(84)
Net earnings (loss)	**216**	**545**	**448**	**248**	672	136	(93)	71
Per share – Basic	**0.21**	**0.53**	**0.44**	**0.24**	0.66	0.13	(0.10)	0.06
Per share – Diluted	**0.16**	**0.53**	**0.44**	**0.24**	0.66	0.13	(0.10)	0.06
Cash flow – operating activities	**1,313**	**1,283**	**1,009**	**529**	1,351	894	813	646
Funds from operations[2]	**583**	**1,318**	**1,208**	**895**	1,014	891	715	686
Per share – Basic	**0.58**	**1.31**	**1.20**	**0.89**	1.01	0.89	0.71	0.68
Per share – Diluted	**0.58**	**1.31**	**1.20**	**0.89**	1.01	0.89	0.71	0.68
U.S./Canadian dollar exchange rate (US$)	**0.757**	**0.765**	**0.775**	**0.791**	0.786	0.799	0.744	0.756
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**22.6**	**33.7**	**29.7**	**37.5**	46.6	42.7	56.0	60.7
NGL[3]	**24.8**	**24.5**	**21.8**	**20.5**	21.4	19.3	17.2	14.2
Heavy crude oil	**34.4**	**34.6**	**38.5**	**39.7**	42.3	44.1	43.1	48.0
Bitumen	**132.9**	**117.3**	**123.2**	**123.2**	120.9	117.7	117.4	120.6
Total crude oil & NGL production *(mbbls/day)*	**214.7**	**210.1**	**213.2**	**220.9**	231.2	223.8	233.7	243.5
Natural gas *(mmcf/day)*[3]	**537.6**	**519.5**	**494.0**	**477.0**	534.9	563.4	514.8	543.1
Total production *(mboe/day)*	**304.3**	**296.7**	**295.5**	**300.4**	320.4	317.7	319.5	334.0
Average sales prices								
Light & Medium crude oil *($/bbl)*	**60.19**	**93.84**	**92.23**	**82.08**	77.05	63.13	63.27	66.70
NGL *($/bbl)*[3]	**53.36**	**60.08**	**54.13**	**55.03**	51.19	37.83	38.00	49.64
Heavy crude oil *($/bbl)*	**18.71**	**50.09**	**54.22**	**32.80**	48.64	41.89	42.06	41.28
Bitumen *($/bbl)*	**5.42**	**46.00**	**44.41**	**27.77**	41.88	38.14	37.46	35.20
Natural gas *($/mcf)*[3]	**6.86**	**6.15**	**6.53**	**7.03**	5.89	5.25	5.59	5.35
Operating costs *($/boe)*	**13.75**	**14.68**	**14.22**	**13.33**	13.20	14.12	14.65	13.75
Operating netbacks[3][4]								
Lloydminster Thermal *($/bbl)*[5]	**(0.05)**	**35.83**	**36.16**	**19.77**	33.98	27.38	24.14	24.88
Lloydminster Non-Thermal *($/boe)*[5]	**(11.80)**	**13.28**	**20.83**	**4.13**	19.36	12.46	12.70	14.80
Tucker Thermal *($/bbl)*[5]	**(5.08)**	**29.53**	**31.67**	**16.16**	31.79	28.35	24.09	23.53
Sunrise Energy Project *($/bbl)*[5]	**(25.60)**	**15.79**	**12.59**	**(5.62)**	16.50	16.05	11.67	2.24
Western Canada – Crude Oil *($/bbl)*[5]	**(1.70)**	**23.81**	**29.37**	**17.88**	12.99	3.64	12.03	19.18
Western Canada – NGL & natural gas *($/mcf)*[6]	**1.13**	**0.29**	**0.39**	**1.33**	0.15	0.12	1.01	1.05
Atlantic – Light Oil *($/bbl)*[5]	**23.19**	**68.20**	**57.79**	**65.23**	59.00	35.86	42.08	44.39
Asia Pacific – Light Oil, NGL & natural gas *($/boe)*[3][5]	**67.42**	**65.45**	**68.44**	**70.31**	65.31	61.81	61.90	64.43
Total *($/boe)*[5]	**9.42**	**31.30**	**31.31**	**24.37**	30.00	23.25	23.53	24.17

Segmented Operational Information (continued)	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Upgrading								
Synthetic crude oil sales *(mbbls/day)*	**53.8**	**54.9**	**47.1**	**56.0**	56.5	58.2	30.3	54.1
Total sales *(mbbls/day)*	**73.5**	**76.7**	**69.1**	**79.4**	77.9	79.4	40.3	76.2
Upgrading differential *($/bbl)*	**27.89**	**29.46**	**26.67**	**32.31**	21.46	13.60	18.70	20.88
Canadian Refined Products								
Fuel sales *(millions of litres/day)*	**8.0**	**7.7**	**7.5**	**7.4**	8.0	8.1	6.5	6.4
Refinery throughput[(7)]								
Lloydminster Refinery *(mbbls/day)*	**25.3**	**27.8**	**26.8**	**28.7**	30.1	30.0	19.5	28.0
Prince George Refinery *(mbbls/day)*	**10.7**	**11.5**	**8.8**	**12.0**	11.3	11.9	9.7	11.8
U.S. Refining and Marketing								
Refinery throughput[(7)]								
Lima Refinery *(mbbls/day)*	**105.9**	**163.3**	**171.2**	**164.4**	164.5	178.3	174.1	172.0
BP-Husky Toledo Refinery *(mbbls/day)*[(8)]	**73.2**	**70.8**	**65.5**	**75.0**	81.0	77.3	71.1	77.0
Superior Refinery *(mbbls/day)*[(9)]	**—**	**—**	**10.1**	**37.0**	22.0	—	—	—

(1) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*
(2) *Funds from operations is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the corresponding GAAP measure.*
(3) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*
(4) *Operating netback is a non-GAAP measure. Refer to Section 9.3.*
(5) *Includes associated co-products converted to boe.*
(6) *Includes associated co-products converted to mcfge.*
(7) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(8) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50 percent).*
(9) *The Superior Refinery was acquired on November 8, 2017.*

Significant Items Impacting Gross Revenues, Net Earnings (Loss) and Funds from Operations

Variations in the Company's gross revenues, net earnings (loss) and funds from operations are primarily driven by changes in production volumes, commodity prices, commodity price differentials, refining crack spreads, foreign exchange rates and planned turnarounds. Stronger crude oil prices realized by the Company for the majority of 2018, and increased Asia Pacific production throughout the year, resulted in an increase to Company's gross revenues, net earnings and funds from operations. Other significant items which impacted gross revenues, net earnings and funds from operations over the last eight quarters include:

2018

Q4:

- At the Rush Lake 2 Thermal Project, first production and nameplate capacity of 10,000 bbls/day were achieved.
- At the Spruce Lake North Thermal Project, site clearing was completed.
- At the Tucker Thermal Project, nameplate capacity of 30,000 bbls/day was achieved.
- At the Sunrise Energy Project, nameplate capacity of 60,000 bbls/day was achieved. Additionally, the 10 infill wells previously drilled came online.
- At the Ansell and Kakwa areas, a drilling program targeting the Spirit River Formation continued with six more wells drilled and 12 more were completed.
- At the Karr and Wembley areas, in the Montney Formation, three more wells were drilled and completed.
- On November 16, 2018, a flowline connector separated near the South White Rose Extension Drill Centre, causing a spill of approximately 250 cubic metres of oil. Production at the SeaRose FPSO was shut-in. Operations resumed in the first quarter of 2019.
- The Company is a non-operating partner in two exploration licences awarded in the November 2018 C-NLOPB land sale. The licences are adjacent to Terra Nova and White Rose in the Jeanne d'Arc Basin and will bring the Company's total licence holdings in the region to nine.
- The Company completed its 2018 planned scope of work on the crude oil flexibility project.
- The Company accrued pre-tax insurance recoveries for property damage, rebuild costs and business interruption associated with the incident at the Superior Refinery of $331 million.

Q3:

- At the Rush Lake 2 Thermal Project, construction of the CPF was completed and first steam was achieved.
- At the Dee Valley Thermal Project, drilling of the second well pad was completed and construction of the CPF continued.
- At the Spruce Lake Central Thermal Project, drilling of the first well pad was completed and construction of the CPF commenced.
- At the Tucker Thermal Project, a planned turnaround was completed in support of reaching its 30,000 bbls/day design capacity.
- At the Ansell and Kakwa areas, an accelerated drilling program from an 18-well program to a 25-well development program continued with eight more wells drilled and nine more were completed.
- At the Karr and Wembley areas, in the Montney Formation, two more wells were drilled and three completed.
- An exploration well was drilled on Block 16/25 which encountered hydrocarbons. Additional evaluation works is being conducted.
- At the Madura Strait, the BD Project achieved its gross daily sales targets of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest).
- The Company accrued pre-tax insurance recoveries for property damage and clean-up costs associated with the incident at the Superior Refinery of $110 million.

Q2:

- At the Dee Valley Thermal Project, drilling of the first well pad was completed and construction of the CPF commenced.
- At the Spruce Lake Central Thermal Project, site clearing was completed.
- At the Tucker Thermal Project, production from the remaining five wells of the 15-well D West pad commenced.
- At the Sunrise Energy Project, two infill wells commenced production, and the remaining three of 10 infill wells were drilled.
- At the Karr and Wembley areas, in the Montney Formation, two wells were drilled.
- Construction to develop Liuhua 29-1 commenced.
- Two exploration wells were drilled on Block 15/33 in the South China Sea. The first well was a success and the second well, which was drilled on a separate structure, did not encounter commercial hydrocarbons and was written off.
- The Company and CNOOC signed two PSCs for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea.
- At the West White Rose Project, construction of the concrete gravity structure commenced at the purpose-built graving dock in Argentia, Newfoundland and Labrador.
- An exploration well was drilled north of the main White Rose field. The well encountered a net pay thickness of more than 85 metres of oil-bearing sandstone. The discovery continues to be evaluated and further delineation of the area is planned.
- On April 26, 2018, a fire occurred at the Superior Refinery and operations were suspended. The Company has insurance to cover business interruption, third-party liability and property damage. The Company accrued pre-tax insurance recoveries for property damage associated with the incident of $27 million.

Q1:

- At the Rush Lake 2 Thermal Project, drilling of the 12 SAGD injector-producer well pairs was completed and construction of the CPF continued.
- At the Dee Valley Thermal Project, drilling of the first well pad commenced.
- At the Spruce Lake North and Central thermal projects, site clearing commenced.
- At the Tucker Thermal Project, production from the first 10 wells of the new D West pad commenced.
- At the Sunrise Energy Project, production commenced at the last well pair of the 14 previously drilled well pairs. Two infill wells commenced steaming, and seven out of 10 infill wells were drilled.
- At the Ansell and Kakwa areas, production commenced at the remaining six wells of the 16-well 2017 drilling program. Additionally, an 18-well development program is underway with seven wells drilled and four completed.
- Production operations on the *SeaRose* FPSO vessel were suspended for nine days due to a regulatory suspension.

2017

Q4:

- On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. for $670 million (US$527 million) in cash, which includes $108 million (US$85 million) of working capital.
- At the Tucker Thermal Project, drilling of the new 15-well pad was completed in the second quarter and steaming commenced in the fourth quarter of 2017.
- At the Sunrise Energy Project production continued to ramp-up and the 14 previously drilled well pairs were tied in, with 13 well pairs producing.
- Production from 10 wells of the 16-well program in the Ansell and Kakwa areas was achieved. Due to improved operating efficiencies, drilling times were reduced by 30 percent during 2017, contributing to a 22 percent reduction in per-well drilling costs.
- At Karr in the Montney Formation, two wells were drilled in the third quarter and production was achieved in the fourth quarter.
- Production continued to ramp-up at the BD Project. The first lifting of NGL occurred mid-October.
- An additional infill well was completed at the main White Rose field, which was tied back to the *SeaRose* FPSO, providing for improved capital efficiencies.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 17,600 boe/day for gross proceeds of approximately $65 million resulting in an after-tax gain of $9 million.
- The recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

Q3:

- First production was achieved at the BD Project in the Madura Strait. NGL were produced and stored on the FPSO.
- Nine wells of a 16-well program in the Ansell and Kakwa areas were completed by the third quarter.
- Production from one well at Wembley in the Montney Formation commenced.
- At South White Rose, an oil production well and a supporting water injection well were completed.
- The consolidation of a single expanded truck transport network of approximately 160 sites was completed during the quarter.

Q2:

- The Company recognized an after-tax impairment expense of $123 million related to crude oil and natural gas assets located in Western Canada in the Upstream Exploration and Production segment. The impairment charges were the result of changes in the development plans and reinforced by market transactions.
- Lloydminster Upgrader and Lloydminster Asphalt Refinery throughput and sales volumes were lower due to major planned turnarounds at the Lloydminster Upgrader and Lloydminster Asphalt Refinery.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 2,600 boe/day for gross proceeds of approximately $123 million, resulting in an after-tax gain of $23 million.

Q1:

- First oil was achieved at the Tucker Thermal Project's new eight-well pad.
- First oil was achieved from a North Amethyst infill well.

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production[(1)]				Infrastructure and Marketing				Upgrading			
2018 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**643**	**1,319**	**1,284**	**1,084**	**530**	**601**	**634**	**446**	**307**	**534**	**444**	**465**
Royalties	**(50)**	**(106)**	**(99)**	**(80)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Marketing and other	**—**	**—**	**—**	**—**	**148**	**168**	**187**	**165**	**—**	**—**	**—**	**—**
Revenues, net of royalties	**593**	**1,213**	**1,185**	**1,004**	**678**	**769**	**821**	**611**	**307**	**534**	**444**	**465**
Expenses												
Purchases of crude oil and products	**(1)**	**—**	**1**	**—**	**497**	**567**	**602**	**421**	**110**	**328**	**251**	**239**
Production, operating and transportation expenses	**388**	**398**	**384**	**357**	**4**	**2**	**15**	**2**	**51**	**52**	**46**	**46**
Selling, general and administrative expenses	**72**	**71**	**77**	**76**	**2**	**1**	**1**	**1**	**1**	**2**	**2**	**2**
Depletion, depreciation, amortization and impairment	**469**	**461**	**434**	**447**	**(1)**	**—**	**1**	**—**	**36**	**30**	**29**	**28**
Exploration and evaluation expenses	**53**	**26**	**40**	**30**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Loss (gain) on sale of assets	**—**	**2**	**—**	**(4)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other – net	**(109)**	**(42)**	**27**	**4**	**1**	**(1)**	**—**	**2**	**—**	**—**	**—**	**—**
	872	**916**	**963**	**910**	**503**	**569**	**619**	**426**	**198**	**412**	**328**	**315**
Earnings (loss) from operating activities	**(279)**	**297**	**222**	**94**	**175**	**200**	**202**	**185**	**109**	**122**	**116**	**150**
Share of equity investment income (loss)	**18**	**12**	**17**	**4**	**(2)**	**6**	**9**	**5**	**—**	**—**	**—**	**—**
Financial items												
Net foreign exchange gains (losses)	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance income	**—**	**2**	**1**	**9**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance expenses	**(29)**	**(29)**	**(22)**	**(29)**	**—**	**—**	**—**	**—**	**—**	**(1)**	**—**	**—**
	(29)	**(27)**	**(21)**	**(20)**	**—**	**—**	**—**	**—**	**—**	**(1)**	**—**	**—**
Earnings (loss) before income tax	**(290)**	**282**	**218**	**78**	**173**	**206**	**211**	**190**	**109**	**121**	**116**	**150**
Provisions for (recovery of) income taxes												
Current	**(233)**	**(46)**	**(106)**	**(99)**	**193**	**14**	**84**	**63**	**40**	**47**	**36**	**45**
Deferred	**149**	**114**	**166**	**120**	**(146)**	**43**	**(27)**	**(11)**	**(11)**	**(14)**	**(4)**	**(4)**
	(84)	**68**	**60**	**21**	**47**	**57**	**57**	**52**	**29**	**33**	**32**	**41**
Net earnings (loss)	**(206)**	**214**	**158**	**57**	**126**	**149**	**154**	**138**	**80**	**88**	**84**	**109**
Capital expenditures[(3)]	**898**	**715**	**524**	**519**	**—**	**—**	**(15)**	**15**	**9**	**9**	**33**	**11**
Total assets	**19,175**	**18,410**	**18,263**	**18,070**	**1,301**	**1,529**	**1,519**	**1,417**	**1,149**	**1,308**	**1,275**	**1,270**

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

(3) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period. Includes Exploration and Production assets acquired through acquisition, and excludes assets acquired through corporate acquisition.*

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
821	1,001	869	721	2,766	3,198	3,035	2,771	(173)	(521)	(470)	(390)	4,894	6,132	5,796	5,097
—	—	—	—	—	—	—	—	—	—	—	—	(50)	(106)	(99)	(80)
—	—	—	—	—	—	—	—	—	—	—	—	148	168	187	165
821	1,001	869	721	2,766	3,198	3,035	2,771	(173)	(521)	(470)	(390)	4,992	6,194	5,884	5,182
637	834	711	578	2,523	2,741	2,565	2,505	(173)	(521)	(470)	(390)	3,593	3,949	3,660	3,353
67	66	72	60	193	222	217	163	(2)	—	—	—	701	740	734	628
11	12	11	13	5	5	7	5	21	96	88	72	112	187	186	169
29	29	28	29	102	129	125	94	27	23	22	20	662	672	639	618
—	—	—	—	—	—	—	—	—	—	—	—	53	26	40	30
—	(2)	—	—	—	—	—	—	—	—	—	—	—	—	—	(4)
(1)	—	—	—	(334)	(107)	(29)	6	1	—	(9)	—	(442)	(150)	(11)	12
743	939	822	680	2,489	2,990	2,885	2,773	(126)	(402)	(369)	(298)	4,679	5,424	5,248	4,806
78	62	47	41	277	208	150	(2)	(47)	(119)	(101)	(92)	313	770	636	376
—	—	—	—	—	—	—	—	—	—	—	—	16	18	26	9
—	—	—	—	—	—	—	—	(2)	(9)	3	22	(2)	(9)	3	22
—	—	—	—	—	—	—	—	16	13	12	11	16	15	13	20
(3)	(3)	(3)	(3)	(3)	(4)	(3)	(4)	(41)	(43)	(46)	(48)	(76)	(80)	(74)	(84)
(3)	(3)	(3)	(3)	(3)	(4)	(3)	(4)	(27)	(39)	(31)	(15)	(62)	(74)	(58)	(42)
75	59	44	38	274	204	147	(6)	(74)	(158)	(132)	(107)	267	714	604	343
41	15	19	25	3	2	2	2	(18)	(19)	(17)	(18)	26	13	18	18
(21)	1	(7)	(15)	58	44	30	(3)	(4)	(32)	(20)	(10)	25	156	138	77
20	16	12	10	61	46	32	(1)	(22)	(51)	(37)	(28)	51	169	156	95
55	43	32	28	213	158	115	(5)	(52)	(107)	(95)	(79)	216	545	448	248
22	23	18	11	296	196	118	55	40	25	30	26	1,265	968	708	637
1,431	1,578	1,578	1,547	8,566	8,209	8,003	7,926	3,603	3,641	3,354	3,057	35,225	34,675	33,992	33,287

2017 ($ millions)	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,355	1,157	1,215	1,251	704	513	426	333	452	377	227	384
Royalties	(97)	(71)	(91)	(104)	—	—	—	—	—	—	—	—
Marketing and other	—	—	—	—	(71)	(4)	(1)	36	—	—	—	—
Revenues, net of royalties	1,258	1,086	1,124	1,147	633	509	425	369	452	377	227	384
Expenses												
Purchases of crude oil and products	(1)	—	1	—	657	495	408	295	304	287	144	248
Production, operating and transportation expenses	390	413	430	417	7	1	2	3	49	45	54	49
Selling, general and administrative expenses	84	63	61	57	1	1	1	1	3	1	3	2
Depletion, depreciation, amortization and impairment	471	514	705	547	—	1	1	—	30	31	19	19
Exploration and evaluation expenses	38	31	56	21	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets	(13)	3	(33)	1	—	—	—	1	—	—	—	—
Other – net	37	(7)	(39)	15	(6)	10	(9)	(3)	—	—	—	—
	1,006	1,017	1,181	1,058	659	508	403	297	386	364	220	318
Earnings (loss) from operating activities	252	69	(57)	89	(26)	1	22	72	66	13	7	66
Share of equity investment income (loss)	13	(1)	(1)	1	(12)	13	24	24	—	—	—	—
Financial items												
Net foreign exchange gains (losses)	—	—	—	—	—	—	—	—	—	—	—	—
Finance income	1	2	1	1	—	—	—	—	—	—	—	—
Finance expenses	(33)	(31)	(35)	(32)	—	—	—	—	—	(1)	—	—
	(32)	(29)	(34)	(31)	—	—	—	—	—	(1)	—	—
Earnings (loss) before income tax	233	39	(92)	59	(38)	14	46	96	66	12	7	66
Provisions for (recovery of) income taxes												
Current	(8)	(25)	12	(13)	—	—	—	—	24	12	4	23
Deferred	71	36	(37)	29	(11)	4	13	26	(6)	(9)	(2)	(5)
	63	11	(25)	16	(11)	4	13	26	18	3	2	18
Net earnings (loss)	170	28	(67)	43	(27)	10	33	70	48	9	5	48
Capital expenditures[4]	525	355	307	289	—	—	—	—	14	27	168	21
Total assets	17,920	18,021	18,275	18,802	1,364	1,447	1,338	1,422	1,263	1,261	1,179	1,129

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

(3) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*

(4) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period. Includes Exploration and Production assets acquired through acquisition, and excludes assets acquired through corporate acquisition.*

Downstream (continued)								Corporate and Eliminations[(2)]				Total			
Canadian Refined Products				U.S. Refining and Marketing[(3)]											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,605	4,717	4,352	4,312
—	—	—	—	—	—	—	—	—	—	—	—	(97)	(71)	(91)	(104)
—	—	—	—	—	—	—	—	—	—	—	—	(71)	(4)	(1)	36
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,437	4,642	4,260	4,244
647	650	477	445	2,316	1,876	1,894	1,973	(476)	(424)	(253)	(397)	3,447	2,884	2,671	2,564
66	63	67	60	151	135	137	140	—	—	—	—	663	657	690	669
19	12	11	11	4	4	3	4	121	61	63	59	232	142	142	134
28	27	27	29	90	82	93	89	28	18	17	16	647	673	862	700
—	—	—	—	—	—	—	—	—	—	—	—	38	31	56	21
—	(5)	—	—	—	—	—	—	—	—	—	—	(13)	(2)	(33)	2
(1)	—	—	—	(14)	10	(14)	(3)	(3)	12	(3)	—	13	25	(65)	9
759	747	582	545	2,547	2,107	2,113	2,203	(330)	(333)	(176)	(322)	5,027	4,410	4,323	4,099
56	55	20	23	208	185	22	(30)	(146)	(91)	(77)	(75)	410	232	(63)	145
—	—	—	—	—	—	—	—	—	—	—	—	1	12	23	25
—	—	—	—	—	—	—	—	5	2	(11)	(2)	5	2	(11)	(2)
—	—	—	—	—	—	—	—	10	9	8	5	11	11	9	6
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(59)	(58)	(62)	(55)	(99)	(97)	(103)	(93)
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(44)	(47)	(65)	(52)	(83)	(84)	(105)	(89)
53	52	17	20	204	181	19	(33)	(190)	(138)	(142)	(127)	328	160	(145)	81
18	11	6	10	(4)	5	1	—	(14)	(31)	(18)	(16)	16	(28)	5	4
(4)	3	(1)	(5)	79	62	6	(12)	(489)	(44)	(36)	(27)	(360)	52	(57)	6
14	14	5	5	75	67	7	(12)	(503)	(75)	(54)	(43)	(344)	24	(52)	10
39	38	12	15	129	114	12	(21)	313	(63)	(88)	(84)	672	136	(93)	71
25	14	37	11	122	88	52	51	59	27	16	12	745	511	580	384
1,548	1,533	1,516	1,503	7,580	6,676	6,769	7,035	3,252	3,219	3,295	3,003	32,927	32,157	32,372	32,894

Management's Report

The management of Husky Energy Inc. ("the Company") is responsible for the financial information and operating data presented in this financial document.

The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this financial document has been prepared on a basis consistent with that in the consolidated financial statements.

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Company's internal control over financial reporting was effective as of December 31, 2018. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, internal auditors as well as the external auditors, to discuss audit (external, internal and joint venture), internal controls, accounting policy and financial reporting matters as well as the reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board. The Committee is also responsible for the appointment of the external auditors for the Company.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with the standards of the Public Company Accounting Oversight Board (United States) on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

Robert J. Peabody
President & Chief Executive Officer

Jeffrey R. Hart
Chief Financial Officer

Calgary, Canada
February 25, 2019

Independent Auditors' Report

To the Shareholders and Board of Directors of Husky Energy Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Husky Energy Inc. (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 25, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

We have served as the Company's auditor since 1951.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 25, 2019

Consolidated Financial Statements

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2018**	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents *(note 4)*	**2,866**	2,513
Accounts receivable *(notes 5, 24)*	**1,355**	1,186
Income taxes receivable	**112**	164
Inventories *(note 6)*	**1,232**	1,513
Prepaid expenses	**123**	145
Restricted cash *(notes 7, 16)*	**—**	95
	5,688	5,616
Restricted cash *(notes 7, 16)*	**128**	97
Exploration and evaluation assets *(note 8)*	**997**	838
Property, plant and equipment, net *(note 9)*	**25,800**	24,078
Goodwill *(note 10)*	**690**	633
Investment in joint ventures *(note 11)*	**1,319**	1,238
Long-term income taxes receivable	**243**	242
Other assets *(note 12)*	**360**	185
Total Assets	**35,225**	32,927
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 14)*	**3,159**	3,033
Short-term debt *(note 15)*	**200**	200
Long-term debt due within one year *(note 15)*	**1,433**	—
Asset retirement obligations *(note 16)*	**202**	274
	4,994	3,507
Long-term debt *(note 15)*	**4,114**	5,240
Other long-term liabilities *(note 17)*	**1,107**	1,237
Asset retirement obligations *(note 16)*	**2,222**	2,252
Deferred tax liabilities *(note 18)*	**3,174**	2,724
Total Liabilities	**15,611**	14,960
Shareholders' equity		
Common shares *(note 19)*	**7,293**	7,293
Preferred shares *(note 19)*	**874**	874
Contributed surplus	**2**	2
Retained earnings	**10,273**	9,207
Accumulated other comprehensive income	**1,160**	580
Non-controlling interest	**12**	11
Total Shareholders' Equity	**19,614**	17,967
Total Liabilities and Shareholders' Equity	**35,225**	32,927

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Robert J. Peabody
Director

William Shurniak
Director

Consolidated Statements of Income

(millions of Canadian dollars, except share data)	Years ended December 31, 2018	2017
Gross revenues	**21,919**	18,986
Royalties	**(335)**	(363)
Marketing and other	**668**	(40)
Revenues, net of royalties	**22,252**	18,583
Expenses		
Purchases of crude oil and products	**14,555**	11,566
Production, operating and transportation expenses *(note 20)*	**2,803**	2,679
Selling, general and administrative expenses *(note 20)*	**654**	650
Depletion, depreciation, amortization and impairment *(note 9)*	**2,591**	2,882
Exploration and evaluation expenses *(note 8)*	**149**	146
Gain on sale of assets *(note 9)*	**(4)**	(46)
Other – net *(note 9)*	**(591)**	(18)
	20,157	17,859
Earnings from operating activities	**2,095**	724
Share of equity investment gain *(note 11)*	**69**	61
Financial items *(note 21)*		
Net foreign exchange gains (losses)	**14**	(6)
Finance income	**64**	37
Finance expenses	**(314)**	(392)
	(236)	(361)
Earnings before income taxes	**1,928**	424
Provisions for (recovery of) income taxes *(note 18)*		
Current	**75**	(3)
Deferred	**396**	(359)
	471	(362)
Net earnings	**1,457**	786
Earnings per share *(note 19)*		
Basic	**1.41**	0.75
Diluted	**1.40**	0.75
Weighted average number of common shares outstanding *(note 19)*		
Basic *(millions)*	**1,005.1**	1,005.3
Diluted *(millions)*	**1,006.1**	1,005.3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars)	Years ended December 31, 2018	2017
Net earnings	**1,457**	786
Other comprehensive income (loss)		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans *(note 22)*	**46**	(7)
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedge *(notes 24)*	**(13)**	(2)
Equity investment – share of other comprehensive income (loss)	**(2)**	3
Exchange differences on translation of foreign operations	**857**	(653)
Hedge of net investment *(note 24)*	**(262)**	243
Other comprehensive income (loss)	**626**	(416)
Comprehensive income	**2,083**	370

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

	Attributable to Equity Holders							
					AOCI [1]			
(millions of Canadian dollars)	Common Shares	Preferred Shares	Contributed Surplus	Retained Earnings	Foreign Currency Translation	Hedging	Non-Controlling Interest	Total Shareholders' Equity
Balance as at December 31, 2016	7,296	874	—	8,457	969	20	11	17,627
Net earnings	—	—	—	786	—	—	—	786
Other comprehensive income (loss)								
Remeasurements of pension plans (net of tax recovery of $4 million) *(notes 18, 22)*	—	—	—	(7)	—	—	—	(7)
Derivatives designated as cash flow hedges (net of tax recovery of less than $1 million) *(notes 18, 24)*	—	—	—	—	—	(2)	—	(2)
Equity investment – share of other comprehensive income	—	—	—	—	—	3	—	3
Exchange differences on translation of foreign operations (net of tax recovery of $82 million) *(note 18)*	—	—	—	—	(653)	—	—	(653)
Hedge of net investment (net of tax expense of $38 million) *(notes 18, 24)*	—	—	—	—	243	—	—	243
Total comprehensive income (loss)	—	—	—	779	(410)	1	—	370
Transactions with owners recognized directly in equity:								
Dividends declared on preferred shares *(note 19)*	—	—	—	(34)	—	—	—	(34)
Share cancellation	(3)	—	2	5	—	—	—	4
Balance as at December 31, 2017	7,293	874	2	9,207	559	21	11	17,967
Net earnings	**—**	**—**	**—**	**1,457**	**—**	**—**	**—**	**1,457**
Other comprehensive income (loss)								
Remeasurements of pension plans (net of tax expense of $17 million) *(notes 18, 22)*	**—**	**—**	**—**	**46**	**—**	**—**	**—**	**46**
Derivatives designated as cash flow hedges (net of tax recovery of $5 million) *(notes 18, 24)*	**—**	**—**	**—**	**—**	**—**	**(13)**	**—**	**(13)**
Equity investment – share of other comprehensive loss	**—**	**—**	**—**	**—**	**—**	**(2)**	**—**	**(2)**
Exchange differences on translation of foreign operations (net of tax expense of $87 million) *(note 18)*	**—**	**—**	**—**	**—**	**857**	**—**	**—**	**857**
Hedge of net investment (net of tax recovery of $41 million) *(notes 18, 24)*	**—**	**—**	**—**	**—**	**(262)**	**—**	**—**	**(262)**
Total comprehensive income (loss)	**—**	**—**	**—**	**1,503**	**595**	**(15)**	**—**	**2,083**
Transactions with owners recognized directly in equity:								
Dividends declared on common shares *(note 19)*	**—**	**—**	**—**	**(402)**	**—**	**—**	**—**	**(402)**
Dividends declared on preferred shares *(note 19)*	**—**	**—**	**—**	**(35)**	**—**	**—**	**—**	**(35)**
Non-controlling interest in subsidiary	**—**	**—**	**—**	**—**	**—**	**—**	**1**	**1**
Balance as at December 31, 2018	**7,293**	**874**	**2**	**10,273**	**1,154**	**6**	**12**	**19,614**

[1] Accumulated other comprehensive income.
The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

(millions of Canadian dollars)	Years ended December 31, 2018	2017
Operating activities		
Net earnings	**1,457**	786
Items not affecting cash:		
Accretion *(notes 16, 21)*	**97**	112
Depletion, depreciation, amortization and impairment *(note 9)*	**2,591**	2,882
Inventory write-down to net realizable value *(note 6)*	**60**	—
Exploration and evaluation expenses *(note 8)*	**29**	6
Deferred income taxes *(note 18)*	**396**	(359)
Foreign exchange	**(6)**	(4)
Stock-based compensation *(notes 19, 20)*	**44**	45
Gain on sale of assets *(note 9)*	**(4)**	(46)
Unrealized mark to market loss (gain) *(note 24)*	**(150)**	56
Share of equity investment gain *(note 11)*	**(69)**	(61)
Gain on insurance recoveries for damage to property *(note 9)*	**(253)**	—
Other	**21**	16
Settlement of asset retirement obligations *(note 16)*	**(181)**	(136)
Deferred revenue *(note 17)*	**(100)**	(16)
Distribution from joint ventures *(note 11)*	**72**	25
Change in non-cash working capital *(note 23)*	**130**	398
Cash flow – operating activities	**4,134**	3,704
Financing activities		
Long-term debt issuance *(note 15)*	**—**	750
Long-term debt repayment *(note 15)*	**—**	(365)
Debt issue costs *(note 15)*	**—**	(6)
Dividends on common shares *(note 19)*	**(402)**	—
Dividends on preferred shares *(note 19)*	**(35)**	(34)
Other	**(8)**	18
Change in non-cash working capital *(note 23)*	**120**	—
Cash flow – financing activities	**(325)**	363
Investing activities		
Capital expenditures	**(3,578)**	(2,220)
Capitalized interest *(note 21)*	**(108)**	(68)
Corporate acquisition *(note 9)*	**(15)**	(670)
Proceeds from asset sales *(note 9)*	**4**	192
Contribution payable payment *(note 11)*	**—**	(142)
Contribution to joint ventures *(note 11)*	**(40)**	(81)
Other	**(19)**	(40)
Change in non-cash working capital *(note 23)*	**235**	240
Cash flow – investing activities	**(3,521)**	(2,789)
Increase in cash and cash equivalents	**288**	1,278
Effect of exchange rates on cash and cash equivalents	**65**	(84)
Cash and cash equivalents at beginning of year	**2,513**	1,319
Cash and cash equivalents at end of year	**2,866**	2,513
Supplementary cash flow information		
Net interest paid	**(285)**	(344)
Net Income taxes received (paid)	**(37)**	41

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

Note 1 Description of Business and Segmented Disclosures

Husky Energy Inc. ("Husky" or "the Company") is an international integrated energy company incorporated under the Business Corporations Act (Alberta). The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares, Series 1, Cumulative Redeemable Preferred Shares, Series 2, Cumulative Redeemable Preferred Shares, Series 3, Cumulative Redeemable Preferred Shares, Series 5 and Cumulative Redeemable Preferred Shares, Series 7 are listed under the symbols, "HSE.PR.A","HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The registered office is located at 707, 8th Avenue S.W., PO Box 6525, Station D, Calgary, Alberta, T2P 3G7.

Management has identified segments for the Company's business based on differences in products, services and management responsibility. The Company's business is conducted predominantly through two major business segments – Upstream and Downstream.

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") ("Exploration and Production") and the marketing of the Company's and other producers' crude oil, natural gas, NGLs, sulphur and petroleum coke. Additionally, it includes pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas ("Infrastructure and Marketing"). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Alberta, Saskatchewan, and British Columbia ("Western Canada"), offshore east coast of Canada ("Atlantic") and offshore China and offshore Indonesia ("Asia Pacific").

Downstream operations in the Integrated Corridor include upgrading of heavy crude oil feedstock into synthetic crude oil in Canada ("Upgrading"), refining crude oil in Canada, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining in the U.S. of primarily crude oil to produce and market asphalt, gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards ("U.S. Refining and Marketing"). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and are grouped together as the Downstream business segment due to the similar nature of their products and services.

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production(1)		Infrastructure and Marketing(2)		Total	
Year ended December 31,	**2018**	2017	**2018**	2017	**2018**	2017
Gross revenues	**4,330**	4,978	**2,211**	1,976	**6,541**	6,954
Royalties	**(335)**	(363)	**—**	—	**(335)**	(363)
Marketing and other	**—**	—	**668**	(40)	**668**	(40)
Revenues, net of royalties	**3,995**	4,615	**2,879**	1,936	**6,874**	6,551
Expenses						
Purchases of crude oil and products	**—**	—	**2,087**	1,855	**2,087**	1,855
Production, operating and transportation expenses	**1,527**	1,650	**23**	13	**1,550**	1,663
Selling, general and administrative expenses	**296**	265	**5**	4	**301**	269
Depletion, depreciation, amortization and impairment	**1,811**	2,237	**—**	2	**1,811**	2,239
Exploration and evaluation expenses	**149**	146	**—**	—	**149**	146
Loss (gain) on sale of assets	**(2)**	(42)	**—**	1	**(2)**	(41)
Other – net	**(120)**	6	**2**	(8)	**(118)**	(2)
	3,661	4,262	**2,117**	1,867	**5,778**	6,129
Earnings (loss) from operating activities	**334**	353	**762**	69	**1,096**	422
Share of equity investment gain	**51**	12	**18**	49	**69**	61
Financial items						
Net foreign exchange gain (loss)	**—**	—	**—**	—	**—**	—
Finance income	**12**	5	**—**	—	**12**	5
Finance expenses	**(109)**	(131)	**—**	—	**(109)**	(131)
	(97)	(126)	**—**	—	**(97)**	(126)
Earnings (loss) before income taxes	**288**	239	**780**	118	**1,068**	357
Provisions for (recovery of) income taxes						
Current	**(484)**	(34)	**354**	—	**(130)**	(34)
Deferred	**549**	99	**(141)**	32	**408**	131
	65	65	**213**	32	**278**	97
Net earnings (loss)	**223**	174	**567**	86	**790**	260
Intersegment revenues	**1,155**	1,250	**—**	—	**1,155**	1,250

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Includes $172 million of revenue (2017 - $280 million) and $142 million of associated costs (2017 - $234 million) for construction contracts, inclusive of $172 million of revenue (2017 - $259 million) and$142 million of costs (2017 - $236 million) for contracts in progress accounted for under the percentage of completion method.*

(3) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices. Segment results include transactions between business segments.*

Segmented Financial Information Con't

Downstream								Corporate and Eliminations[3]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
1,750	1,440	**3,412**	2,787	**11,770**	9,355	**16,932**	13,582	**(1,554)**	(1,550)	**21,919**	18,986
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(335)**	(363)
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**668**	(40)
1,750	1,440	**3,412**	2,787	**11,770**	9,355	**16,932**	13,582	**(1,554)**	(1,550)	**22,252**	18,583
928	983	**2,760**	2,219	**10,334**	8,059	**14,022**	11,261	**(1,554)**	(1,550)	**14,555**	11,566
195	197	**265**	256	**795**	563	**1,255**	1,016	**(2)**	—	**2,803**	2,679
7	9	**47**	53	**22**	15	**76**	77	**277**	304	**654**	650
123	99	**115**	111	**450**	354	**688**	564	**92**	79	**2,591**	2,882
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**149**	146
—	—	**(2)**	(5)	**—**	—	**(2)**	(5)	**—**	—	**(4)**	(46)
—	—	**(1)**	(1)	**(464)**	(21)	**(465)**	(22)	**(8)**	6	**(591)**	(18)
1,253	1,288	**3,184**	2,633	**11,137**	8,970	**15,574**	12,891	**(1,195)**	(1,161)	**20,157**	17,859
497	152	**228**	154	**633**	385	**1,358**	691	**(359)**	(389)	**2,095**	724
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**69**	61
—	—	**—**	—	**—**	—	**—**	—	**14**	(6)	**14**	(6)
—	—	**—**	—	**—**	—	**—**	—	**52**	32	**64**	37
(1)	(1)	**(12)**	(12)	**(14)**	(14)	**(27)**	(27)	**(178)**	(234)	**(314)**	(392)
(1)	(1)	**(12)**	(12)	**(14)**	(14)	**(27)**	(27)	**(112)**	(208)	**(236)**	(361)
496	151	**216**	142	**619**	371	**1,331**	664	**(471)**	(597)	**1,928**	424
168	63	**100**	45	**9**	2	**277**	110	**(72)**	(79)	**75**	(3)
(33)	(22)	**(42)**	(7)	**129**	135	**54**	106	**(66)**	(596)	**396**	(359)
135	41	**58**	38	**138**	137	**331**	216	**(138)**	(675)	**471**	(362)
361	110	**158**	104	**481**	234	**1,000**	448	**(333)**	78	**1,457**	786
290	192	**109**	108	**—**	—	**399**	300	**—**	—	**1,554**	1,550

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2018**	2017	**2018**	2017	**2018**	2017
Expenditures on exploration and evaluation assets[2]	**242**	148	**—**	—	**242**	148
Expenditures on property, plant and equipment[2]	**2,414**	1,328	**—**	—	**2,414**	1,328
As at December 31,						
Exploration and evaluation assets	**997**	838	**—**	—	**997**	838
Developing and producing assets at cost	**44,196**	41,804	**—**	—	**44,196**	41,804
Accumulated depletion, depreciation, amortization and impairment	**(27,379)**	(26,014)	**—**	—	**(27,379)**	(26,014)
Other property, plant and equipment at cost	**—**	—	**101**	89	**101**	89
Accumulated depletion, depreciation and amortization	**—**	—	**(50)**	(50)	**(50)**	(50)
Total exploration and evaluation assets and property, plant and equipment, net	**17,814**	16,628	**51**	39	**17,865**	16,667
Total assets	**19,175**	17,920	**1,301**	1,364	**20,476**	19,284

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the year. Includes Exploration and Production assets acquired through acquisition, but excludes assets acquired through corporate acquisition.*

Geographical Financial Information

($ millions)	Canada		United States	
Year ended December 31,	**2018**	2017	**2018**	2017
Gross revenues[1]	**9,000**	8,599	**11,770**	9,355
Royalties	**(269)**	(303)	**—**	—
Marketing and other	**668**	(40)	**—**	—
Revenue, net of royalties	**9,399**	8,256	**11,770**	9,355
As at December 31,				
Restricted cash – non-current	**—**	—	**—**	—
Exploration and evaluation assets	**935**	831	**—**	—
Property, plant and equipment, net	**16,433**	15,478	**6,336**	5,595
Goodwill	**—**	—	**690**	633
Investment in joint ventures	**669**	685	**—**	—
Long-term income tax receivable	**243**	242	**—**	—
Other assets[2]	**58**	64	**276**	21
Total non-current assets	**18,338**	17,300	**7,302**	6,249

(1) *Sales to external customers are based on the location of the seller.*

(2) *Includes insurance proceeds of $253 million (2017 - nil), related to the Superior Refinery incident.*

Segmented Financial Information Con't

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**242**	148
62	230	**74**	87	**665**	313	**801**	630	**121**	114	**3,336**	2,072
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**997**	838
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**44,196**	41,804
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(27,379)**	(26,014)
2,659	2,600	**2,789**	2,704	**9,746**	8,300	**15,194**	13,604	**1,251**	1,124	**16,546**	14,817
(1,585)	(1,463)	**(1,581)**	(1,466)	**(3,410)**	(2,705)	**(6,576)**	(5,634)	**(937)**	(845)	**(7,563)**	(6,529)
1,074	1,137	**1,208**	1,238	**6,336**	5,595	**8,618**	7,970	**314**	279	**26,797**	24,916
1,149	1,263	**1,431**	1,548	**8,566**	7,580	**11,146**	10,391	**3,603**	3,252	**35,225**	32,927

Geographical Financial Information Con't

China		Other International		Total	
2018	2017	**2018**	2017	**2018**	2017
1,149	1,032	**—**	—	**21,919**	18,986
(66)	(60)	**—**	—	**(335)**	(363)
—	—	**—**	—	**668**	(40)
1,083	972	**—**	—	**22,252**	18,583
128	97	**—**	—	**128**	97
57	3	**5**	4	**997**	838
3,030	3,005	**1**	—	**25,800**	24,078
—	—	**—**	—	**690**	633
—	—	**650**	553	**1,319**	1,238
—	—	**—**	—	**243**	242
—	78	**26**	22	**360**	185
3,215	3,183	**682**	579	**29,537**	27,311

Disaggregation of Revenue

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2018**	2017	**2018**	2017	**2018**	2017
Primary Geographical Markets						
Canada	**3,181**	3,946	**2,211**	1,976	**5,392**	5,922
United States	**—**	—	**—**	—	**—**	—
China	**1,149**	1,032	**—**	—	**1,149**	1,032
Total revenue	**4,330**	4,978	**2,211**	1,976	**6,541**	6,954
Major Product Lines						
Light & medium crude oil	**948**	1,273	**—**	—	**948**	1,273
Heavy crude oil	**527**	703	**—**	—	**527**	703
Bitumen	**1,367**	1,662	**—**	—	**1,367**	1,662
Total crude oil	**2,842**	3,638	**—**	—	**2,842**	3,638
NGL	**381**	276	**—**	—	**381**	276
Natural gas	**1,107**	1,064	**—**	—	**1,107**	1,064
Total exploration and production	**4,330**	4,978	**—**	—	**4,330**	4,978
Total infrastructure and marketing	**—**	—	**2,211**	1,976	**2,211**	1,976
Synthetic crude	**—**	—	**—**	—	**—**	—
Gasoline	**—**	—	**—**	—	**—**	—
Diesel & distillates	**—**	—	**—**	—	**—**	—
Asphalt	**—**	—	**—**	—	**—**	—
Other	**—**	—	**—**	—	**—**	—
Total refined products	**—**	—	**—**	—	**—**	—
Total revenue	**4,330**	4,978	**2,211**	1,976	**6,541**	6,954

Disaggregation of Revenue Con’t

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
1,750	1,440	**3,412**	2,787	**—**	—	**5,162**	4,227	**(1,554)**	(1,550)	**9,000**	8,599
—	—	**—**	—	**11,770**	9,355	**11,770**	9,355	**—**	—	**11,770**	9,355
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**1,149**	1,032
1,750	1,440	**3,412**	2,787	**11,770**	9,355	**16,932**	13,582	**(1,554)**	(1,550)	**21,919**	18,986
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**948**	1,273
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**527**	703
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**1,367**	1,662
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**2,842**	3,638
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**381**	276
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**1,107**	1,064
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**4,330**	4,978
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**2,211**	1,976
1,445	1,235	**—**	—	**—**	—	**1,445**	1,235	**—**	—	**1,445**	1,235
—	—	**1,070**	925	**6,157**	5,198	**7,227**	6,123	**—**	—	**7,227**	6,123
278	196	**1,303**	917	**4,297**	3,435	**5,878**	4,548	**—**	—	**5,878**	4,548
—	—	**454**	362	**165**	31	**619**	393	**—**	—	**619**	393
27	9	**585**	583	**1,151**	691	**1,763**	1,283	**—**	—	**1,763**	1,283
1,750	1,440	**3,412**	2,787	**11,770**	9,355	**16,932**	13,582	**—**	—	**16,932**	13,582
1,750	1,440	**3,412**	2,787	**11,770**	9,355	**16,932**	13,582	**(1,554)**	(1,550)	**21,919**	18,986

Note 2 Basis of Presentation

a) Basis of Measurement and Statement of Compliance

The consolidated financial statements have been prepared by management on a historical cost basis with some exceptions, as detailed in the accounting policies set out below in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These accounting policies have been applied consistently for all periods presented in these consolidated financial statements.

These consolidated financial statements were approved and signed by the Chair of the Audit Committee and the Chief Executive Officer on February 25, 2019 having been duly authorized to do so by the Board of Directors.

Certain prior years' amounts have been reclassified to conform with current presentation.

b) Principles of Consolidation

The consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies to obtain benefits from their activities. The Company's accounts reflect the proportionate share of the assets, liabilities, revenues, expenses and cash flows from the Company's activities that are conducted jointly with third parties. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements. A portion of the Company's activities relate to joint ventures (see Note 11), which are accounted for using the equity method.

c) Use of Estimates, Judgments and Assumptions

The timely preparation of the consolidated financial statements requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates, judgments and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained, and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization and impairment, recoveries from insurance claims, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes and reserves and contingencies are based on estimates.

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include determination of technical feasibility and commercial viability, impairment assessments, the determination of cash generating units ("CGUs"), changes in reserves estimates, the determination of a joint arrangement, the designation of the Company's functional currency and the fair value of related party transactions.

Significant estimates, judgments and assumptions made by management in the preparation of these consolidated financial statements are outlined in detail in Note 3.

d) Functional and Presentation Currency

The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is presented in millions of Canadian dollars, except per share amounts and unless otherwise stated.

The designation of the Company's functional currency is a management judgment based on the currency of the primary economic environment in which the Company operates.

Note 3 Significant Accounting Policies

a) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand less outstanding cheques and deposits with an original maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand and short-term deposits, and the Company has the ability to net settle, the excess is reported in bank operating loans.

Cash and cash equivalents held that are not available for use are classified as restricted cash. When restricted cash is not expected to be used within 12 months, it is classified as a non-current asset.

b) Inventories

Crude oil, natural gas, refined petroleum products and sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials, parts and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead, operating costs, transportation and depreciation, depletion and amortization. Commodity inventories held for trading purposes are carried at fair value and measured at fair value less costs to sell based on Level 2 observable inputs, refer to policy Note 3 (m). Any changes in commodity trading inventory fair value are included as gains or losses in Marketing and Other in the consolidated statements of income, during the period of change. Previous inventory impairment provisions are reversed when there is a change in the condition that caused the impairment and the inventory remains on hand. Unrealized intersegment net earnings on inventory sales are eliminated.

c) Precious Metals

The Company uses precious metals in conjunction with a catalyst as part of the downstream upgrading and refining processes. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to production and operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in net earnings. Precious metals are included in other assets on the balance sheet.

d) Exploration and Evaluation Assets and Property, Plant and Equipment

i) Cost

Oil and gas properties and other property, plant and equipment are recorded at cost, including expenditures that are directly attributable to the purchase or development of an asset. Borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset are included in the asset cost. Capitalization ceases when substantially all activities necessary to prepare the qualifying asset for its intended use are complete.

ii) Exploration and Evaluation Costs

The accounting treatment of costs incurred for oil and natural gas exploration, evaluation and development is determined by the classification of the underlying activities as either exploratory or developmental. The results from an exploration drilling program can take considerable time to analyze, and the determination that commercial reserves have been discovered requires determination of technical feasibility, commercial viability and industry experience. Exploration activities can fluctuate from year to year, due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in exploratory drilling and the degree of risk associated with drilling in particular areas. Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance.

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as exploration and evaluation assets. These costs include costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees. Pre-license costs and geological and geophysical costs associated with exploration activities are expensed in the period incurred. Costs directly associated with an exploration well are initially capitalized as an exploration and evaluation asset until the drilling of the well is complete and the results have been evaluated. If extractable hydrocarbons are found and are likely to be developed commercially, but are subject to further appraisal activity, which may include the drilling of wells, the costs continue to be carried as an exploration and evaluation asset while sufficient and continued progress is made in assessing the commercial viability of the hydrocarbons. Capitalized exploration and evaluation costs or assets are not depreciated and are carried forward until technical feasibility and commercial viability of the area is determined or the assets are determined to be impaired. Management determines technical feasibility and commercial viability when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, establishing commercial and technical feasibility and whether the asset can be developed using a proved development concept and has received internal approval. Upon the determination of technical feasibility and commercial viability, capitalized exploration and evaluation assets are then transferred to property, plant and equipment. All such carried costs are subject to technical, commercial and management review, as well as review for impairment indicators, at least every reporting period to confirm the continued intent to develop or otherwise extract value from the discovery. These costs are also tested for impairment when transferred to property, plant and equipment. Capitalized exploration and evaluation expenditures related to wells that do not find reserves, or where no future activity is planned, are expensed as exploration and evaluation expenses.

The application of the Company's accounting policy for exploration and evaluation costs requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Judgments may change as new information becomes available.

iii) Development Costs

Expenditures, including borrowing costs, on the construction, installation and completion of infrastructure facilities, such as platforms, pipelines and the drilling of development wells, are capitalized as oil and gas properties. Costs incurred to operate and maintain wells and equipment to lift oil and gas to the surface are expensed as production and operating expenses.

iv) Other Property, Plant and Equipment

Repair and maintenance costs, other than major turnaround costs, are expensed as incurred. Major turnaround costs are capitalized as part of property, plant and equipment when incurred and are amortized over the estimated period of time to the anticipated date of the next turnaround.

v) Depletion, Depreciation and Amortization

Oil and gas properties are depleted on a unit-of-production basis over the proved developed reserves of the particular field, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied. The unit-of-production rate for the depletion of oil and gas properties related to total proved plus probable reserves takes into account expenditures incurred to date together with sanctioned future development expenditures required to develop the field.

Oil and gas reserves are evaluated internally and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments and reversal of impairments of property, plant and equipment.

Net reserves represent the Company's undivided gross working interest in total reserves after deducting crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as applicable, as at the balance sheet date and could differ significantly from other points in time throughout the year or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Depreciation for substantially all other property, plant and equipment is provided using the straight-line method based on the estimated useful lives of assets, which range from five to forty-five years, less any estimated residual value. The useful lives of assets are estimated based upon the period the asset is expected to be available for use by the Company. Residual values are based upon the estimated amount that would be obtained on disposal, net of any costs associated with the disposal. Other property, plant and equipment held under finance leases are depreciated over the shorter of the lease term and the estimated useful life of the asset.

Depletion, depreciation and amortization rates for all capitalized costs associated with the Company's activities are reviewed at least annually, or when events or conditions occur that impact capitalized costs, reserves and estimated service lives.

vi) Finance Leases

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the lease property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

All other leases are accounted for as operating leases and the lease costs are expensed as incurred.

e) Joint Arrangements

Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

For a joint operation, the consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of the joint arrangement. The Company reports items of a similar nature to those on the financial statements of the joint arrangement, on a line-by-line basis, from the date that joint control commences until the date that joint control ceases.

Joint ventures are accounted for using the equity method of accounting and recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the joint venture's net assets. The Company's consolidated financial statements include its share of the joint venture's profit or loss and other comprehensive income ("OCI") included in investment in joint ventures, until the date that joint control ceases.

Classification of a joint arrangement as either joint operation or joint venture requires judgment. Management's considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

f) Investments in Associates

An associate is an entity for which the Company has significant influence and thereby has the power to participate in the financial and operational decisions but does not control or jointly control the investee. Investments in associates are accounted for using the equity method of accounting and are recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the investee's net assets. The Company's consolidated financial statements include its share of the investee's profit or loss and OCI until the date that significant influence ceases.

g) Business Combinations

Business combinations are accounted for using the acquisition method. Determining whether an acquisition meets the definition of a business combination or represents an asset purchase requires judgment on a case-by-case basis. If the acquisition meets the definition of a business combination, the assets and liabilities are recognized based on the contractual terms, economic conditions, the Company's operating and accounting policies and other factors that exist on the acquisition date, which is the date on which control is transferred to the Company. The identifiable assets and liabilities are measured at their fair values on the acquisition date with limited exceptions. Any additional consideration payable, contingent upon the occurrence of a future event, is recognized at fair value on the acquisition date; subsequent changes in the fair value of the liability are recognized in net earnings. Acquisition costs incurred are expensed and included in selling, general and administrative expenses in the consolidated statements of income.

h) Goodwill

Goodwill is the excess of the purchase price paid over the recognized amount of net assets acquired through business combinations, which is inherently imprecise as judgment is required in the determination of the fair value of assets and liabilities. Goodwill, which is not amortized, is assigned to appropriate CGUs or groups of CGUs. Goodwill is tested for impairment annually and when circumstances indicate that the carrying value may be impaired. Impairment losses are recognized in net earnings and are not subject to reversal. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal.

i) Impairment and Reversals of Impairment on Non-Financial Assets

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets, are reviewed at the end of each reporting period to determine whether there is an indication of impairment or reversal of previously recorded impairment. If such indication exists, the recoverable amount is estimated.

Determining whether there are any indications of impairment or impairment reversals requires significant judgment of external factors, such as an extended change in prices or margins for oil and gas commodities or refined products, a significant change in an asset's market value, a significant revision of estimated volumes, revision of future development costs, a change in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an impact on the Company's CGUs. If any indication of impairment or impairment reversals exist, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs to sell ("FVLCS") and the asset's value in use ("VIU") for an individual asset or CGU. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Determination of the Company's CGUs is subject to management's judgment.

FVLCS is the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCS is generally determined as the net present value of the estimated future cash flows expected to arise from a CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted using a rate that would be applied by a market participant to arrive at a net present value of the CGU, less cost to dispose.

VIU is the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. VIU is determined by applying assumptions specific to the Company's continued use and can only take into account sanctioned future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, forecasted crack spreads, growth rate, discount rate and, in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and probable volumes and where applicable economically recoverable resources associated with interests in certain Husky properties which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate.

Given that the calculations for recoverable amounts require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and in the case of oil and gas properties, expected production volumes, it is possible that the assumptions may change, which may impact the estimated life of the CGU and may require a material adjustment to the carrying value of goodwill and non-financial assets.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized with respect to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the CGU or group of CGUs on a pro rata basis. Impairment losses are recognized in depletion, depreciation, amortization and impairment in the consolidated statements of income.

Impairment losses recognized in prior years are assessed at the end of each reporting period for indications that the impairment has decreased or no longer exists. An impairment loss is reversed only to the extent that the carrying amount of the asset or CGU does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

j) Asset Retirement Obligations ("ARO")

A liability is recognized for future legal or constructive retirement obligations associated with the Company's assets. The Company has significant obligations to remove tangible assets and restore land after operations cease and the Company retires or relinquishes the asset. The retirement of Upstream and Downstream assets consists primarily of plugging and abandoning wells, abandoning surface and subsea plant and equipment and facilities and restoring land to a state required by regulation or contract. The amount recognized is the net present value of the estimated future expenditures determined in accordance with local conditions, current technology and current regulatory requirements. The obligation is calculated using the current estimated costs to retire the asset inflated to the estimated retirement date and then discounted using a credit-adjusted risk-free discount rate. The liability is recorded in the period in which an obligation arises with a corresponding increase to the carrying value of the related asset. The liability is progressively accreted over time as the effect of discounting unwinds, creating an expense recognized in finance expenses. The costs capitalized to the related assets are amortized in a manner consistent with the depletion, depreciation and amortization of the underlying assets. Actual retirement expenditures are charged against the accumulated liability as incurred.

Liabilities for ARO are adjusted every reporting period for changes in estimates. These adjustments are accounted for as a change in the corresponding capitalized cost, except where a reduction in the provision is greater than the undepreciated capitalized cost of the related assets, in which case the capitalized cost is reduced to nil and the remaining adjustment is recognized in net earnings. Changes to the amount of capitalized costs will result in an adjustment to future depletion, depreciation and amortization, and to finance expenses.

Estimating the ARO requires significant judgment as restoration technologies and costs are constantly changing, as are regulatory, political, environmental and safety considerations. Inherent in the calculation of the ARO are numerous assumptions including the ultimate settlement amounts, future third-party pricing, inflation factors, risk-free discount rates, credit risk, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in material changes to the ARO liability. Adjustments to the estimated amounts and timing of future ARO cash flows are a regular occurrence in light of the significant judgments and estimates involved.

k) Legal and Other Contingent Matters

Provisions and liabilities for legal and other contingent matters are recognized in the period when the circumstance becomes probable that a future cash outflow resulting from past operations or events will occur and the amount of the cash outflow can be reasonably estimated. The timing of recognition and measurement of the provision requires the application of judgment to existing facts and circumstances, which can be subject to change, and the carrying amounts of provisions and liabilities are reviewed regularly and adjusted accordingly. The Company is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations, and determine that the loss can be reasonably estimated. When a loss is recognized, it is charged to net earnings. The Company continually monitors known and potential contingent matters and makes appropriate disclosure and provisions when warranted by the circumstances present.

l) Share Capital

Preferred shares are classified as equity since they are cancellable and redeemable only at the Company's option and dividends are discretionary and payable only if declared by the Board of Directors. Incremental costs directly attributable to the issuance of shares and stock options are recognized as a deduction from equity, net of tax. Common share dividends are paid out in common shares, or in cash, and preferred share dividends are paid in cash. Both common and preferred share dividends are recognized as distributions within equity.

m) Financial Instruments

Financial instruments are any contracts that give rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial assets are classified in one of the following categories: subsequently measured at amortized cost, fair value through other comprehensive income ("FVTOCI"), or fair value through profit or loss ("FVTPL"). Financial liabilities are initially recognized at fair value, and subsequently measured based on classification in one of the following categories: subsequently measured at amortized cost and FVTPL. Financial assets and liabilities are not offset unless there is a currently enforceable legal right to offset the recognized amounts and there is an intention to settle on a net basis, to realize the assets and settle the liabilities simultaneously.

Financial assets and liabilities subsequently measured at amortized costs are measured using the effective interest method. The effective interest method is a method of calculating the amortized costs of a financial liability and of allocating interest expense over the relevant period. Transaction costs that are directly attributable to the acquisition or issue of a financial instrument are measured at amortized cost and added to the fair value initially recognized.

Financial instruments at FVTPL are stated at fair value, with any gains or losses arising on remeasurement recognized in profit or loss. Unrealized gains and losses on FVTPL financial instruments related to trading activities are recognized in marketing and other in the consolidated statements of income, and unrealized gains and losses on all other FVTPL financial instruments are recognized in other - net. Transaction costs directly attributable to the acquisition of financial assets or liabilities at FVTPL are recognized immediately in profit or loss.

Financial instruments at FVTOCI are stated at fair value, with any gains or losses arising on remeasurement recognized in OCI except for impairment gains or losses and foreign exchange gains and losses.

Financial instruments subsequently revalued at fair value are further categorized using a three-level hierarchy that reflects the significance of the inputs used in determining fair value. Level 1 fair value is determined by reference to quoted prices in active markets for identical assets and liabilities. Level 2 fair value is based on inputs that are independently observable for similar assets or liabilities. Level 3 fair value is not based on independently observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value.

A financial asset is derecognized when the contractual rights to the cash flows from the financial asset have expired, or it transfers the contractual rights to receive the cash flows of the financial assets and the Company has transferred substantially all the risks and rewards of ownership of the financial asset. A financial liability is derecognized when the liability is extinguished, discharged, cancelled or expires.

n) Derivative Instruments and Hedging Activities

Derivatives are financial instruments for which the fair value changes in response to market risks, require little or no initial investment and are settled at a future date. Derivative instruments are utilized by the Company to manage various market risks including volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company may enter into swap and other derivative transactions to hedge or mitigate the Company's commercial risk, including derivatives that reduce risks that arise in the ordinary course of the Company's business. The Company may choose to apply hedge accounting to derivative instruments.

The fair values of derivatives are determined using valuation models that require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. When able, the Company will determine fair value by incorporating forward market prices and rates that are compared to quotes received from financial institutions to ensure reasonability. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future results.

i) Derivative Instruments

All derivative instruments, other than those designated as effective hedging instruments or certain non-financial derivative contracts that meet the Company's own use requirements, are classified as FVTPL and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

The Company may enter into commodity price contracts in order to offset fixed or floating prices with market rates to manage exposures to fluctuations in commodity prices. The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The related inventory is measured at fair value based on exit prices. Gains and losses from these derivative contracts, which are not designated as effective hedging instruments, are recognized in revenues or purchases of crude oil and products and are initially recorded at settlement date. Derivative instruments that have been designated as effective hedging instruments are further classified as either fair value or cash flow hedges (see "Hedging Activities").

ii) Embedded Derivatives

Derivatives embedded within a hybrid contract containing a financial asset host are not accounted for separately, rather the whole instrument is classified as FVTPL. Derivatives embedded in other hybrid contracts are recorded separately when the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract and the host contract is not measured at FVTPL. The definition of an embedded derivative is the same as freestanding derivatives. Embedded derivatives are measured at fair value with gains and losses recognized in net earnings.

iii) Hedging Activities

At the inception of a derivative transaction, if the Company elects to use hedge accounting, formal designation and documentation is required. The documentation must include: identification of the hedged item or transaction, the hedging instrument, the nature of the risk being hedged, the Company's risk management objective and strategy for undertaking the hedge and how the Company will assess the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item.

A hedge is assessed at inception and at the end of each reporting period to ensure that it is highly effective in offsetting changes in fair values or cash flows of the hedged item. For a fair value hedge, the gain or loss from remeasuring the hedging instrument at fair value is recognized immediately in net earnings with the offsetting gain or loss on the hedged item. When fair value hedge accounting is discontinued, the carrying amount of the hedging instrument is deferred and amortized to net earnings over the remaining maturity of the hedged item.

For a cash flow hedge, the effective portion of the gain or loss is recorded in OCI. Any hedge or portion of a hedge that is ineffective is immediately recognized in net earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting. Any gain or loss on the hedging instrument resulting from the discontinuation of a cash flow hedge is deferred in OCI until the forecasted transaction date. If the forecasted transaction date is no longer expected to occur, the gain or loss is recognized in net earnings in the period of discontinuation.

A net investment hedge of a foreign operation is accounted for similarly to a cash flow hedge. The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in OCI, net of tax, and are limited to the translation gain or loss on the net investment.

o) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI is comprised of the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge, the exchange gains and losses arising from the translation of foreign operations with a functional currency that is not Canadian dollars and the actuarial gains and losses on defined benefit pension plans. Amounts included in OCI are shown net of tax. Other reserves is an equity category comprised of the cumulative amounts of OCI, relating to foreign currency translation and hedging.

p) Impairment of Financial Assets

A financial asset is assessed at the end of each reporting period to determine whether it is impaired, based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates.

An impairment loss with respect to a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the net present value of the estimated future cash flows discounted at the original effective interest rate, according to the expected credit loss model. Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed for lifetime expected credit losses collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in net earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

Given that the calculations for the net present value of estimated future cash flows related to derivative financial assets require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

q) Pensions and Other Post-employment Benefits

In Canada, the Company provides a defined contribution pension plan and other post-retirement benefits to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. In the United States, the Company provides two defined contribution pension plans (401(k)) and one other post-retirement benefits plan. The Company also maintains a small defined benefit pension plan for the employees of the Superior Refinery.

The cost of the pension benefits earned by employees in the defined contribution pension plans is expensed as incurred. The cost of the benefits earned by employees in the defined benefit pension plans is determined using the projected unit credit funding method. Actuarial gains and losses are recognized in retained earnings as incurred.

The defined benefit asset or liability is comprised of the fair value of plan assets from which the obligations are to be settled and the present value of the defined benefit obligation. Plan assets are measured at fair value based on the closing bid price when there is a quoted price in an active market. Plan assets are assets that are held by a long-term employee benefit fund or qualifying insurance policies. Plan assets are not available to the Company's creditors. The value of any defined benefit asset is restricted to the sum of any past service costs and the present value of refunds from and reductions in future contributions to the plan. Defined benefit obligations are estimated by discounting expected future payments using the year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments.

Post-retirement medical benefits are also provided to qualifying retirees. In some cases the benefits are provided through medical care plans to which the Company, the employees, the retirees and covered family members contribute. In some plans there is no funding of the benefits before retirement. These plans are recognized on the same basis as described above for the defined benefit pension plan.

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of assumptions that affect the expected future benefit payments. The valuation of these plans is prepared by an independent actuary engaged by the Company. These assumptions include, but are not limited to, the estimate of expected plan investment performance, salary escalation, retirement age, attrition, future health care costs and mortality. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

The assumptions for each country are reviewed each year and are adjusted where necessary to reflect changes in fund experience and actuarial recommendations. Mortality rates are based on the latest available standard mortality tables for the individual countries concerned. The rate of return on pension plan assets is based on a projection of real long-term bond yields and an equity risk premium, which are combined with local inflation assumptions and applied to the actual asset mix of each plan. The amount of the expected return on plan assets is calculated using the expected rate of return for the year and the fair value of assets at the beginning of the year. Future salary increases are based on expected future inflation rates for the individual countries.

r) Income Taxes

Current income tax is recognized in net earnings in the period unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Any interest and penalties on income taxes are recognized in interest expense and interest payable. Management periodically evaluates positions taken in the Company's tax returns with respect to situations in which applicable tax regulations are subject to interpretation and reassessment and establishes provisions where appropriate.

Deferred tax is measured using the liability method on temporary differences at the reporting date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax assets and liabilities are recognized at expected tax rates in effect in the year when the asset is expected to be realized or the liability settled, based on tax rates and tax laws that have been enacted or substantively enacted at the reporting date. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

s) Asset Exchange Transactions

Asset exchange transactions are measured at cost if the transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. Otherwise, asset exchange transactions are measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up. Gains and losses are recorded in other - net in the consolidated statements of income in the period they occur.

t) Revenue Recognition

Revenue is recognized when the performance obligations are satisfied and revenue can be reliably measured. Revenue is measured at the consideration specified in the contract and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. The Company has no obligations for returns, refunds, warranties or similar obligations.

i) Nature of Goods or Services

The following is a description of the principal activities, by operating segment, from which the Company generates revenue.

a) Upstream

The Upstream segment includes Exploration and Production, and Infrastructure and Marketing.

i) Exploration and Production

Exploration and Production principally generates revenue from the sale of crude oil, bitumen, natural gas, and NGLs, as well as crude oil and natural gas processing services. Performance obligations associated with sales of these products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with the sale of processing services are satisfied at the point in time when the services are provided. Royalties are recognized as a reduction to gross revenues. Sales, services and royalties are billed and paid on a monthly basis.

Under take-or-pay contracts, the Company makes a long-term supply commitment in return for a commitment from the buyer to pay for minimum quantities, whether or not the customer takes delivery. If a buyer has a right to get a "make-up" delivery at a later date the performance obligation is not satisfied and revenue is deferred and recognized only when the product is delivered or the make-up product can no longer be taken. Determining when the make-up product can no longer be taken, or how much can no longer be taken, requires estimates of future deliveries. Changes in these estimates may result in a material difference in deferred revenue recognized. If no such option exists within the contractual terms, performance obligation is satisfied, and revenue is recognized when the take-or-pay penalty is triggered.

Physical exchanges of inventory are recognized as non-monetary exchanges and are reported on a net basis for swaps of similar items, as are sales and purchases made with a common counterparty as part of an arrangement similar to a physical exchange.

ii) Infrastructure and Marketing

Infrastructure and Marketing principally generates revenue from marketing the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas. Performance obligations associated with sales of these products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with transportation, blending and storage are satisfied at the point in time when the services are provided. Sales, services and royalties are billed and paid on a monthly basis. Infrastructure and Marketing also includes revenue from construction services provided to Husky Midstream Limited Partnership ("HMLP"), of which the Company owns 35 percent. The Company acts as the general contractor for HMLP projects for fixed price and cost plus contracts. Revenue from fixed price contracts is recognized using the percentage of completion method based on costs incurred. Revenue from cost plus contracts are recognized as services are performed. Construction services are billed and paid on a monthly basis, with unbilled percentage of completion payments billed on completion of the project.

b) Downstream

The Downstream segment includes Upgrading, Canadian Refined Products, and U.S. Refining and Marketing.

i) Upgrading

Upgrading principally generates revenue from the sale of synthetic crude oil in Canada, upgraded from heavy oil feedstock. Performance obligations associated with sales of these products are satisfied at the point in time when the products are delivered to and title passes to the customer. Sales are billed and paid on a monthly basis.

ii) Canadian Refined Products

Canadian Refined Products principally generates revenue from refining of crude oil and marketing of refined petroleum products, including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol. Canadian Refined Products also includes, the Company's retail gasoline and diesel distribution and sales network. Performance obligations associated with sales of these products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with marketing services are satisfied when the services are performed. Sales for retail gasoline, diesel and ancillary products are billed and paid upon delivery. All other sales and services are billed and paid on a weekly or monthly basis.

iii) U.S. Refining and Marketing

U.S. Refining and Marketing primarily generates revenue from refining crude oil to produce and market gasoline, jet fuel and diesel fuels. Performance obligations associated with sale of these products are satisfied at the point in time when the products are delivered to and title passes to the customer. All sales are billed and paid on a weekly or monthly basis.

Performance obligations associated with the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with the sale of transportation, processing and natural gas storage services are satisfied at the point in time when the services are provided. All amounts are due upon delivery of goods or when services are provided.

c) Corporate and Eliminations

Corporate and Eliminations primarily generates revenue from finance income. Finance income is recognized as the interest accrues using the effective interest rate, which is the rate that discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset. Corporate and Eliminations also includes the elimination of sales of crude oil, bitumen, natural gas and NGLs between segments.

u) Foreign Currency

Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The financial statements of Husky's subsidiaries are translated into Canadian dollars, which is the presentation and functional currency of the Company. The assets and liabilities of subsidiaries whose functional currencies are other than Canadian dollars are translated into Canadian dollars at the foreign exchange rate at the balance sheet date, while revenues and expenses of such subsidiaries are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation are included in OCI.

The Company's transactions in foreign currencies are translated to the appropriate functional currency at the foreign exchange rate on the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date and differences arising on translation are recognized in net earnings. Non-monetary assets that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the dates of the transactions.

v) Share-based Payments

In accordance with the Company's stock option plan, stock options to acquire common shares may be granted to officers and certain other employees. The Company records compensation expense over the vesting period based on the fair value of options granted. Compensation expense is recorded in net earnings as part of selling, general and administrative expenses.

The Company's stock option plan is a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for the stock options is accrued over their vesting period and measured at fair value using the Black-Scholes option pricing model. The liability is revalued each reporting period until it is settled to reflect changes in the fair value of the options. The net change is recognized in net earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital.

The Company's Performance Share Unit Plan provides a time-vested award to certain officers and employees of the Company. Performance Share Units ("PSU") entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash payment is contingent on the Company's total shareholder return relative to a peer group of companies and achieving a return on capital in use ("ROCIU") target. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. A liability for expected cash payments is accrued over the vesting period of the PSUs and is revalued at each reporting date based on the market price of the Company's common shares and the expected vesting percentage. Upon vesting, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount.

w) Earnings per Share

The number of basic common shares outstanding is the weighted average number of common shares outstanding for each period. Shares issued during the period are included in the weighted average number of shares from the date consideration is received. The calculation of basic earnings per common share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding.

The number of diluted common shares outstanding is calculated using the treasury stock method, which assumes that any proceeds received from in-the-money stock options would be used to buy back common shares at the average market price for the period. The calculation of diluted earnings per share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding adjusted for the effects of all potential dilutive common share issuances, which are comprised of common shares issuable upon exercise of stock options granted to employees. Stock options granted to employees provide the holder with the ability to settle in cash or equity. For the purposes of the diluted earnings per share calculation, the Company must adjust the numerator for the more dilutive effect of cash-settlement versus equity-settlement despite how the stock options are accounted for in net earnings. As a result, net earnings reported based on accounting of cash-settled stock options may be adjusted for the results of equity-settlements for the purposes of determining the numerator for the diluted earnings per share calculation.

x) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. If a grant is received but reasonable assurance and compliance with conditions is not achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the grant relates to an expense item, it is recognized as income in the period in which the costs are incurred. Where the grant relates to an asset, it is recognized as a reduction to the net book value of the related asset and recognized in net earnings in equal amounts over the expected useful life of the related asset through lower depletion, depreciation and amortization.

y) Related Party Judgments and Estimates

The Company entered into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. These transactions are on terms equivalent to those that prevail in arm's length transactions, unless otherwise noted. Proceeds for disposition of assets to related parties are recognized at fair value, based on discounted cash flow forecast from those assets. Independent opinions of the fair value may be obtained. Changes in the assumptions used to determine these fair values may result in a material difference in the proceeds and any gain or loss on disposition.

Revenue from fixed price construction contracts are recognized using the percentage of completion method based on costs incurred, which requires estimating the expected costs to complete a project. Changes in these assumptions may result in a material difference in the construction revenue recognized. See Note 25.

z) Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

i) Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the consolidated statements of income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. Optional exemptions to not recognize certain short-term leases or leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged.

The Company will adopt IFRS 16 on the effective date of January 1, 2019 and has selected the modified retrospective transition approach. The optional exemptions to not recognize certain short-term and low value leases will be applied.

For leases implemented January 1, 2019, the Company will recognize a right-of-use asset of $1.1 billion equal to the lease liability at the present value of the remaining lease payments discounted using the Company's incremental borrowing rate. The implementation of IFRS 16 does not have a material impact on the consolidated statements of income. Due to a change in classification of operating lease expenses, cash flow from operating activities will increase and cash flow from financing activities will decrease, with no overall impact to the cash position for the Company.

aa) Change in Accounting Policy

i) Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15 Revenue from Contracts with Customers, deferring the effective date to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 15 did not require any material adjustments to the amounts recorded in the consolidated financial statements; however, additional disclosures are presented in the consolidated financial statements.

Revenue is recognized when the performance obligations are satisfied and revenue can be reliably measured. Revenue is measured at the consideration specified in the contracts and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Natural gas sales in Asia Pacific are under long-term, fixed price contracts. Substantially all other revenue is based on floating prices. Performance obligations associated with the sale of crude oil, crude oil equivalents, and refined products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with processing services, transportation, blending and storage, and marketing services are satisfied at the point in time when the services are provided.

ii) Financial Instruments

In July 2014, the IASB issued IFRS 9 Financial Instruments to replace IAS 39, which provides a single model for classification and measurement based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial instruments. For financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in a more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard was effective for annual periods beginning on January 1, 2018. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 9 did not require any material adjustments to the consolidated financial statements.

Financial assets previously classified as loans and receivables (cash and cash equivalents, accounts receivable, restricted cash, and long-term receivables), as well as financial liabilities previously classified as other financial liabilities (accounts payable and accrued liabilities, short-term debt, and long-term debt) have been reclassified to amortized cost. The carrying value and measurement of all financial instruments remains unchanged. The Company's current process for assessing short-term receivables lifetime expected credit losses collectively in groups that share similar credit risk characteristics is unadjusted with the adoption of the new impairment model and resulted in no additional impairment allowance. Additionally, long-term receivables were assessed individually under the expected credit loss model and no impairment was concluded.

iii) Amendments to IFRS 2 Share-based payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018. The amendments clarify how to account for certain types of share-based payment arrangements. The adoption of the amendments did not have a material impact on the Company's consolidated financial statements.

Note 4 Cash and Cash Equivalents

Cash and cash equivalents at December 31, 2018 included $187 million of cash (December 31, 2017 – $280 million) and $2,679 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2017 – $2,233 million).

Note 5 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2018**	December 31, 2017
Trade receivables	**1,146**	1,170
Provision for expected credit losses	**(39)**	(34)
Derivatives due within one year	**43**	17
Other[(1)]	**205**	33
End of year	**1,355**	1,186

(1) *Includes insurance proceeds of $143 million (2017 - nil), related to the Superior Refinery incident.*

Note 6 Inventories

Inventories

($ millions)	**December 31, 2018**	December 31, 2017
Crude oil, natural gas and NGL	**445**	539
Refined petroleum products	**435**	548
Trading inventories measured at fair value less costs to sell	**200**	237
Materials, supplies and other	**152**	189
End of year	**1,232**	1,513

Impairment of inventory to net realizable value for the year ended December 31, 2018 was $60 million (December 31, 2017 – nil), as a result of declining market benchmark prices.

Trading inventories measured at fair value less costs to sell consist of natural gas inventories and crude oil inventories. The fair value measurement incorporates exit commodity prices and adjustments for quality and location. Refer to Note 24.

Note 7 Restricted Cash

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds into separate accounts restricted to the funding of future asset retirement obligations in offshore China. As at December 31, 2018, the Company had deposited funds of $128 million which have been classified as non-current (2017 – $97 million). As at December 31, 2017, the Company deposited funds of $192 million, of which $95 million related to the Wenchang field and was classified as current. The Company's participation in the Wenchang field expired in November 2017, and the amount of the decommissioning and disposal expenses was finalized in January 2018.

Note 8 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	**2018**	2017
Beginning of year	**838**	1,066
Additions	**287**	224
Disposals	**(23)**	—
Transfers to oil and gas properties *(note 9)*	**(79)**	(377)
Expensed exploration expenditures previously capitalized	**(29)**	(6)
Exchange adjustments	**3**	(69)
End of year	**997**	838

The following exploration and evaluation expenses for the years ended December 31, 2018 and 2017 relate to activities associated with the exploration for and evaluation of crude oil and natural gas resources and were recorded in the Upstream Exploration and Production business.

Exploration and Evaluation Expense Summary

($ millions)	**2018**	2017
Seismic, geological and geophysical	**102**	113
Expensed drilling	**41**	22
Expensed land	**6**	11
	149	146

Note 9 Property, Plant and Equipment

Property, Plant and Equipment ($ millions)	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
Cost						
December 31, 2016	44,801	137	2,367	8,645	2,755	58,705
Additions[1]	1,371	11	230	561	140	2,313
Acquisitions	29	—	—	577	—	606
Transfers from exploration and evaluation *(note 8)*	377	—	—	—	—	377
Intersegment transfers	48	(61)	—	—	13	—
Changes in asset retirement obligations *(note 16)*	150	—	2	13	23	188
Disposals and derecognition	(4,702)	—	—	(39)	—	(4,741)
Exchange adjustments	(259)	(1)	—	(566)	(1)	(827)
December 31, 2017	41,815	86	2,599	9,191	2,930	56,621
Additions	**2,465**	**12**	**62**	**744**	**151**	**3,434**
Acquisitions	**64**	**—**	**—**	**3**	**—**	**67**
Transfers from exploration and evaluation *(note 8)*	**79**	**—**	**—**	**—**	**—**	**79**
Intersegment transfers	**—**	**—**	**—**	**(5)**	**5**	**—**
Changes in asset retirement obligations *(note 16)*	**43**	**2**	**(2)**	**(5)**	**7**	**45**
Disposals and derecognition	**(632)**	**—**	**—**	**(10)**	**(1)**	**(643)**
Exchange adjustments	**362**	**1**	**—**	**773**	**3**	**1,139**
December 31, 2018	**44,196**	**101**	**2,659**	**10,691**	**3,095**	**60,742**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2016	(27,986)	(96)	(1,363)	(2,975)	(1,692)	(34,112)
Depletion, depreciation, amortization and impairment	(2,238)	(2)	(99)	(406)	(137)	(2,882)
Intersegment transfers	(37)	50	—	—	(13)	—
Disposals and derecognition	4,124	—	—	16	—	4,140
Exchange adjustments	121	1	—	189	—	311
December 31, 2017	(26,016)	(47)	(1,462)	(3,176)	(1,842)	(32,543)
Depletion, depreciation, amortization and impairment	**(1,811)**	**(2)**	**(123)**	**(503)**	**(152)**	**(2,591)**
Disposals and derecognition	**586**	**—**	**—**	**10**	**—**	**596**
Exchange adjustments	**(138)**	**(1)**	**—**	**(264)**	**(1)**	**(404)**
December 31, 2018	**(27,379)**	**(50)**	**(1,585)**	**(3,933)**	**(1,995)**	**(34,942)**
Net book value						
December 31, 2017	15,799	39	1,137	6,015	1,088	24,078
December 31, 2018	**16,817**	**51**	**1,074**	**6,758**	**1,100**	**25,800**

(1) *Additions include assets under finance lease.*

Depletion, depreciation, amortization and impairment for the year ended December 31, 2018 included a $56 million derecognition of the carrying value reflected in the second and third quarter of 2018 for damage caused by an incident at the Superior Refinery in the Company's U.S Refining and Marketing segment (December 31, 2017 – a pre-tax impairment expense of $173 million in the Upstream Exploration and Production segment).

In addition, the Company accrued pre-tax recoveries for property damage, rebuild costs, business interruption and clean-up costs associated with the Superior Refinery incident of $468 million for the year ended December 31, 2018, which is included in other-net in the consolidated statements of income.

The provisions for derecognition and insurance recoveries are based on management's best estimates as at December 31, 2018, with measurement uncertainty around the provision for property damage, and business interruption insurance recoveries. As the assessment of damage is ongoing, the provisions may be subject to changes.

Costs of property, plant and equipment, including major development projects, not subject to depletion, depreciation and amortization as at December 31, 2018 were $5.2 billion (December 31, 2017 – $2.8 billion) including undeveloped land assets of $117 million as at December 31, 2018 (December 31, 2017 – $57 million).

The net book values of assets held under finance lease within property, plant and equipment are as follows:

Assets Under Finance Lease ($ millions)	Refining	Oil and Gas Properties	Total
December 31, 2017	152	335	487
December 31, 2018	**141**	**323**	**464**

Assets Dispositions

During 2017, the Company completed the sale of select assets in Western Canada to third parties for gross proceeds of approximately $185 million, resulting in a pre-tax gain of $46 million and an after-tax gain of $36 million. The assets and related liabilities were recorded in the Upstream Exploration and Production segment.

Assets Acquisitions

On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. ("Calumet") for $670 million (US$527 million).

The acquisition has been accounted for as a business combination using the acquisition method.

Purchase Price Allocation ($ millions)	USD	CAD
Working capital	85	108
Property, plant and equipment	454	577
Asset retirement obligation	(7)	(9)
Other long-term liabilities	(5)	(6)
Net assets acquired	**527**	**670**

The fair values of accounts receivable and accounts payable approximate their carrying values due to their short-term nature. The fair value of inventory was determined using quoted prices. The fair values of property, plant and equipment were determined based on a cost and future cash flow approach. For the cost approach, key assumptions included the cost to construct the assets and the remaining useful life. For the cash flow approach, key assumptions were the discount rate and future commodity prices. The decommissioning provision was based on the fair value of estimated future reclamation costs. Key assumptions included discount rates, cost estimates and timeline to abandon and reclaim the refinery.

The acquisition of Superior Refinery contributed $163 million to gross revenues and a loss of $13 million to consolidated net earnings from the acquisition date to December 31, 2017.

Had the acquisition occurred on January 1, 2017, the Superior Refinery would have contributed $1.1 billion to gross revenues and $93 million to consolidated net earnings, which would have resulted in gross revenues of $19.9 billion and consolidated net earnings of $892 million for the year ended December 31, 2017.

Note 10 Goodwill

Goodwill

($ millions)	December 31, 2018	December 31, 2017
Beginning of year	**633**	679
Exchange adjustments	**57**	(46)
End of year	**690**	633

As at December 31, 2018, the Company's goodwill balance related entirely to the Lima Refinery. For impairment testing purposes, the recoverable amount of the Lima Refinery CGU was estimated using the higher of FVLCS and VIU methodology based on cash flows expected over a 50-year period and discounted using an after-tax discount rate of 8 percent.

Management used the higher of FVLCS and VIU calculations for the Lima Refinery CGU, which are sensitive to changes in discount rate, forecasted crack spreads and growth rate. The discount rate is derived from the post-tax weighted average cost of capital, of a group of relevant peers, considered to represent the rate of return that would be required by a typical market participant for similar assets, with appropriate adjustments made to reflect the risks specific to the refinery. Forecasted crack spreads are based on WTI and prices for gasoline and diesel, and are consistent with crack spreads used in the Company's long range plan.

Cash flow projections for the initial 10-year period are based on long range plan future cash flows and inflated by long-term growth rates of 1 percent and 2 percent, for future EBITDA and capital expenditures, respectively, for the remaining 40-year period. The inflation rate was based upon an average expected inflation rate for the U.S. of 2 percent and adjusted for throughput capacity constraints (2017 – 2 percent). As at December 31, 2018, the recoverable value of the CGU exceeded the carrying amount and no impairment was identified.

The Company used comparative market multipliers to corroborate discounted cash flow results.

Note 11 Joint Arrangements

Joint Operations

BP-Husky Refining LLC

The Company holds a 50 percent ownership interest in BP-Husky Refining LLC, which owns and operates the BP-Husky Toledo Refinery in Ohio. On March 31, 2008, the Company completed a transaction with BP whereby BP contributed the BP-Husky Toledo Refinery plus inventories and other related net assets and the Company contributed US$250 million in cash and a contribution payable of US $2.6 billion.

The Company amended the terms of payment of the Company's contribution payable with BP-Husky Refining LLC in the first quarter of 2015. In accordance with the amendment, US$1 billion of the net contribution payable was paid on February 2, 2015. Subsequent to the payment, BP-Husky Refining LLC distributed US$1 billion to each of the joint arrangement partners, which resulted in the creation of a deferred tax asset and deferred tax recovery of $203 million. As a result of the prepayment, the accretion rate was reduced from 6 percent to 2.5 percent for the future term of the agreement and the remaining maturity date was extended to December 31, 2017. The remaining net contribution payable amount of approximately US$110 million (CDN $142 million) was repaid in 2017.

Sunrise Oil Sands Partnership

The Company holds a 50 percent interest in the Sunrise Oil Sands Partnership, which is engaged in operating an oil sands project in Northern Alberta.

Joint Venture

Husky-CNOOC Madura Ltd.

The Company currently holds 40 percent joint control in Husky-CNOOC Madura Ltd., which is engaged in the exploration for and production of oil and gas resources in Indonesia. Results of the joint venture are included in the consolidated statements of income in Exploration and Production in the Upstream segment.

Summarized below is the financial information for Husky-CNOOC Madura Ltd. accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	**2018**	2017
Revenues	**441**	97
Expenses	**(273)**	(80)
Net earnings	**168**	17
Share of equity investment *(percent)*	**40%**	40%
Proportionate share of equity investment	**51**	12

Balance Sheets

($ millions, except share of equity investment)	**December 31, 2018**	December 31, 2017
Current assets(1)	**373**	152
Non-current assets	**2,072**	1,993
Current liabilities	**(123)**	(106)
Non-current liabilities(2)	**(1,917)**	(1,813)
Net assets	**405**	226
Share of net assets *(percent)*	**40%**	40%
Carrying amount in balance sheet	**650**	553

(1) *Includes cash and cash equivalents of $203 million (2017 – $26 million).*
(2) *Includes deferred revenue of $2 million (2017 - nil) related to take-or-pay commitments, with respect to natural gas production volumes from the BD Project, not taken by the purchaser. As per the terms of the agreement, the purchaser has until the end of the agreement to take these volumes.*

The Company's share of equity investment and carrying amount of share of net assets does not equal the 40 percent joint control of the expenses and net assets of Husky-CNOOC Madura Ltd. due to differences in the accounting policies of the joint venture and the Company and non-current liabilities of the joint venture which are not included in the Company's carrying amount of net assets due to equity accounting.

Husky Midstream Limited Partnership

On July 15, 2016, the Company completed the sale of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan. The assets are held by a newly-formed limited partnership, HMLP,of which Husky owns 35 percent, Power Assets Holdings Ltd. ("PAH") owns 48.75 percent and CK Infrastructure Holdings Ltd. ("CKI") owns 16.25 percent. Results of the joint venture are included in the consolidated statements of income in Infrastructure and Marketing in the Upstream segment.

Summarized below is the financial information for HMLP accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	**2018**	2017
Revenues	**296**	294
Expenses	**(177)**	(107)
Net earnings	**119**	187
Share of equity investment *(percent)*	**35%**	35%
Proportionate share of equity investment	**18**	49

Balance Sheet

($ millions, except share of net assets)	**December 31, 2018**	December 31, 2017
Current assets[1]	**115**	152
Non-current assets	**2,849**	2,617
Current liabilities	**(153)**	(75)
Non-current liabilities	**(825)**	(690)
Net assets	**1,986**	2,004
Share of net assets *(percent)*	**35%**	35%
Carrying amount in balance sheet	**669**	685

(1) *Current assets include cash and cash equivalents of $16 million (2017 – $28 million).*

The Company's share of equity investment and carrying amount of share of net assets does not equal the 35 percent joint control of the net income and net assets of HMLP due to the potential fluctuation in the partnership profit structure.

Note 12 Other Assets

Other Assets

($ millions)	**December 31, 2018**	December 31, 2017
Long-term receivables[1]	**319**	144
Leasehold incentives	**—**	2
Precious metals	**23**	21
Other	**18**	18
End of year	**360**	185

(1) *Includes insurance proceeds of $253 million (2017 – nil), related to the Superior Refinery incident.*

Note 13 Bank Operating Loans

At December 31, 2018, the Company had unsecured short-term borrowing lines of credit with banks totalling $900 million[1] (December 31, 2017 – $850 million) and letters of credit under these lines of credit totalling $439 million (December 31, 2017 – $422 million). As at December 31, 2018, bank operating loans were nil (December 31, 2017 – nil). Interest payable is based on Bankers' Acceptance, CAD Prime Rate, U.S. LIBOR, or U.S. Base Rates.

Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million (December 31, 2017 – $10 million) available for general purposes. The Company's proportionate share of the liability for any drawings under this credit facility is $5 million (December 31, 2017 – $5 million). As at December 31, 2018, there was no balance outstanding under this credit facility (December 31, 2017 – no balance).

(1) *Includes $125 million demand facilities available specifically for letters of credit only.*

Note 14 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	**December 31, 2018**	December 31, 2017
Trade payables	**1,121**	950
Accrued liabilities	**1,712**	1,791
Dividend payable *(note 19)*	**126**	9
Stock-based compensation	**32**	30
Derivatives due within one year	**39**	115
Other	**129**	138
End of year	**3,159**	3,033

Note 15 Debt and Credit Facilities

Short-term Debt

($ millions)	December 31, 2018	December 31, 2017
Commercial paper[1]	**200**	200

[1] *The commercial paper is supported by the Company's syndicated credit facilities and the Company is authorized to issue commercial paper up to a maximum of $1.0 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2018 was 2.20 percent per annum (December 31, 2017 – 1.40 percent).*

Long-term Debt

		Canadian $ Amount		U.S. $ Denominated	
($ millions)	Maturity	December 31, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Long-term debt					
6.15% notes[1][3]	2019	**—**	376	**—**	300
7.25% notes[1][4]	2019	**—**	939	**—**	750
5.00% notes[5]	2020	**400**	400	**—**	—
3.95% notes[1][4]	2022	**682**	626	**500**	500
4.00% notes[1][4]	2024	**1,023**	939	**750**	750
3.55% notes[5]	2025	**750**	750	**—**	—
3.60% notes[5]	2027	**750**	750	**—**	—
6.80% notes[1][4]	2037	**528**	484	**387**	387
Debt issue costs[2]		**(19)**	(24)	**—**	—
Long-term debt		**4,114**	5,240	**1,637**	2,687
Long-term debt due within one year					
6.15% notes[1][3]	2019	**410**	—	**300**	—
7.25% notes[1][4]	2019	**1,023**	—	**750**	—
Long-term debt due within one year		**1,433**	—	**1,050**	—

[1] *All of the Company's U.S. dollar denominated debt is designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency. Refer to Note 24 for Foreign Currency Risk Management.*
[2] *Calculated using the effective interest rate method.*
[3] *The 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002.*
[4] *The 7.25%, the 3.95%, the 4.00% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007.*
[5] *The 5.00%, the 3.55% and the 3.60% notes represent unsecured securities under a trust indenture dated December 21, 2009.*

Credit Facilities

On November 30, 2017, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on June 19, 2018, was extended to June 19, 2022.

As at December 31, 2018 the covenant under the Company's syndicated credit facilities was a debt to capital covenant, calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2018, and assessed the risk of non-compliance to be low. As at December 31, 2018, the Company had no borrowings under its $2.0 billion facility expiring March 9, 2020 (December 31, 2017 – no borrowings) and no borrowings under its $2.0 billion facility expiring June 19, 2022 (December 31, 2017 – no borrowings).

There continues to be no difference between the terms of these facilities, other than their maturity dates. Interest payable is based on Bankers' Acceptance, CAD Prime Rate, U.S. LIBOR, or U.S. Base Rates, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

Notes

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027. This was completed by way of a prospectus supplement dated March 7, 2017, to the Company's universal short form base shelf prospectus dated February 23, 2015. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019.

On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.

On January 29, 2018, the Company filed a universal short form base shelf prospectus (the "2018 U.S. Shelf Prospectus") with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement with the SEC containing the 2018 U.S. Shelf Prospectus became effective which enables the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. up to and including February 29, 2020.

On December 4, 2018, the Company entered into cash flow hedges using forward interest rate swaps to fix the underlying U.S. $500 million 10-year note fixed rate to December 15, 2019. Refer to Note 24.

At December 31, 2018, the Company had unused capacity of $3.0 billion under its 2017 Canadian Shelf Prospectus and US$3.0 billion under its 2018 U.S. Shelf Prospectus and related U.S. registration statement.

The Company's notes, credit facilities and short-term lines of credit rank equally in right of payment.

Reconciliation of Changes of Liabilities to Cash Flows from Financing Activities

	Liabilities			
($ millions)	Short-term debt	Long-term debt due within one year	Long-term debt	Other long-term liabilities
December 31, 2017	200	—	5,240	1,237
Changes from financing cash flows				
Long-term debt issuance	—	—	—	—
Long-term debt repayment	—	—	—	—
Short-term debt issuance	—	—	—	—
Short-term debt repayment	—	—	—	—
Debt issue costs	—	—	—	—
Total change from financing cash flows	—	—	—	—
Other changes – liability-related				
Reclassification to short-term	—	**1,399**	**(1,399)**	—
Foreign exchange	—	—	—	**32**
Fair value changes	—	—	—	**(67)**
Addition of finance lease obligations	—	—	—	—
Payment of finance lease obligations	—	—	—	**(15)**
Deferred revenue	—	—	—	**(100)**
Amortization of debt issuance costs	—	—	**4**	—
Foreign exchange recognized in OCI	—	**34**	**269**	—
Other	—	—	—	**20**
Total other changes – liability related	—	**1,433**	**(1,126)**	**(130)**
December 31, 2018	**200**	**1,433**	**4,114**	**1,107**

Note 16 Asset Retirement Obligations

At December 31, 2018, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $9.2 billion (December 31, 2017 – $9.7 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 45 years (December 31, 2017 – 42 years) into the future. This amount has been discounted using credit-adjusted risk-free rates of 3.8 percent to 5.0 percent (December 31, 2017 – 2.9 percent to 4.8 percent) and an inflation rate of 2 percent (December 31, 2017 – 2 percent). Obligations related to future environmental remediation and cleanup of oil and gas assets are included in the estimated ARO.

The change in the provision in 2018 is primarily related to increased decommissioning and restoration activities and increase in the average discount rate, partially offset by an increase in the estimated cost of decommissioning activities.

While the provision is based on management's best estimates of future costs, discount rates and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

A reconciliation of the carrying amount of asset retirement obligations at December 31, 2018 and 2017 is set out below:

Asset Retirement Obligations

($ millions)	**2018**	2017
Beginning of year	**2,526**	2,791
Additions	**40**	47
Liabilities settled	**(270)**	(136)
Liabilities disposed	**(11)**	(420)
Change in discount rate	**(68)**	143
Change in estimates	**93**	(2)
Exchange adjustment	**17**	(9)
Accretion *(note 21)*	**97**	112
End of year	**2,424**	2,526
Expected to be incurred within 1 year	**202**	274
Expected to be incurred beyond 1 year	**2,222**	2,252

At December 31, 2018, the Company had deposited funds of $128 million into the restricted accounts for funding of future asset retirement obligations in offshore China. These amounts have been classified as non-current and included in restricted cash. At December 31, 2017, the Company had deposited funds of $192 million, of which $95 million related to the Wenchang field and was classified as current, the remaining balance of $97 million was classified as non-current. The Company's participation in the Wenchang field expired in November 2017, and the amount of the decommissioning and disposal expenses was finalized in January 2018.

Note 17 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	**December 31, 2018**	December 31, 2017
Employee future benefits *(note 22)*	**205**	248
Finance lease obligations	**467**	498
Stock-based compensation	**42**	32
Deferred revenue	**205**	284
Leasehold incentives	**96**	101
Other	**92**	74
End of year	**1,107**	1,237

Finance lease obligations

The future minimum lease payments under existing finance leases are payable as follows:

	Within 1 year		After 1 year but no more than 5 years		More than 5 years		Total	
($ millions)	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Future minimum lease payments	**69**	69	**242**	258	**1,014**	993	**1,325**	1,320
Interest	**48**	48	**175**	174	**613**	594	**836**	816
Present value of minimum lease payments	**66**	66	**180**	194	**243**	244	**489**	504

Deferred revenue

Deferred revenue relates to take-or-pay commitments, with respect to natural gas production volumes from the Liwan 3-1 field in Asia Pacific, not taken by the purchaser. As per the terms of the agreement, the purchaser has until the end of the agreement to take these volumes.

($ millions)	**December 31, 2018**	December 31, 2017
Beginning of year	**284**	321
Take-or-pay payments received	**—**	12
Revenue recognized	**(100)**	(28)
Exchange adjustment	**21**	(21)
End of year	**205**	284

Note 18 Income Taxes

The major components of income tax expense for the years ended December 31, 2018 and 2017 were as follows:

Income Tax Expense (Recovery)

($ millions)	**2018**	2017
Current income tax		
Current income tax charge	**86**	28
Adjustments to current income tax estimates	**(11)**	(31)
	75	(3)
Deferred income tax		
Relating to origination and reversal of temporary differences	**378**	83
Adjustments to deferred income tax estimates	**18**	(442)
	396	(359)

Deferred Tax Items in OCI

($ millions)	**2018**	2017
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**(5)**	—
Remeasurement of pension plans	**17**	(4)
Exchange differences on translation of foreign operations	**87**	(82)
Hedge of net investment	**(41)**	38
	58	(48)

The provision for income taxes in the consolidated statements of income reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31, 2018 and 2017 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	**2018**	2017
Earnings before income taxes		
Canada	**734**	(440)
United States	**493**	301
Other foreign jurisdictions	**701**	563
	1,928	424
Statutory Canadian income tax rate *(percent)*	**27.2%**	27.1%
Expected income tax	**525**	115
Effect on income tax resulting from:		
Foreign jurisdictions	**(36)**	20
Non-taxable items	**(13)**	(1)
Adjustments with respect to previous year	**7**	(473)
Revaluation of foreign tax pools	**(4)**	(8)
Other – net	**(8)**	(15)
Income tax expense (recovery)	**471**	(362)

The statutory tax rate is 27.2 percent in 2018 (2017 – 27.1 percent). The 2018 and 2017 tax rates were similar due to no significant changes to tax rates.

Effective January 1, 2018, the U.S. Federal corporate tax rate was reduced from 35 percent to 21 percent. Included in income tax expense for the year ended December 31, 2017 was a $436 million deferred income tax recovery related to the revaluation of the U.S. deferred tax liabilities.

The following reconciles the movements in the deferred income tax liabilities and assets:

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2018	Recognized in Earnings	Recognized in OCI	Other	**December 31, 2018**
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(3,727)	**(260)**	**(106)**	**4**	**(4,089)**
Foreign exchange gains taxable on realization	(177)	**(43)**	**46**	**—**	**(174)**
Debt issue costs	(3)	**(1)**	**—**	**—**	**(4)**
Other temporary differences	(90)	**62**	**—**	**—**	**(28)**
Deferred tax assets					
Pension plans	40	**(15)**	**(17)**	**—**	**8**
Asset retirement obligations	679	**(29)**	**4**	**—**	**654**
Loss carry-forwards	523	**(70)**	**15**	**—**	**468**
Financial assets at fair value	31	**(40)**	**—**	**—**	**(9)**
	(2,724)	**(396)**	**(58)**	**4**	**(3,174)**

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2017	Recognized in Earnings	Recognized in OCI	Other	December 31, 2017
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(3,998)	187	104	(20)	(3,727)
Foreign exchange gains taxable on realization	(224)	85	(38)	—	(177)
Debt issue costs	(2)	(1)	—	—	(3)
Other temporary differences	(21)	(69)	—	—	(90)
Deferred tax assets					
Pension plans	32	4	4	—	40
Asset retirement obligations	693	(8)	(6)	—	679
Loss carry-forwards	389	150	(16)	—	523
Financial assets at fair value	20	11	—	—	31
	(3,111)	359	48	(20)	(2,724)

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2018, the Company had nil deferred tax liabilities in respect to these investments (December 31, 2017 – nil).

At December 31, 2018, the Company had $1,806 million (December 31, 2017 – $2,031 million) of tax losses that will expire between 2030 and 2037. The Company has recorded deferred tax assets in respect of these losses, as there are sufficient taxable temporary differences in the various jurisdictions to utilize these losses.

Note 19 Share Capital

Common Shares

The Company is authorized to issue an unlimited number of no par value common shares.

Common Shares	Number of Shares	Amount ($ millions)
December 31, 2016	1,005,451,854	7,296
Share cancellation	(331,842)	(3)
December 31, 2017	1,005,120,012	7,293
Options exercised [1]	**1,726**	**—**
December 31, 2018	**1,005,121,738**	**7,293**

[1] *Stock options exercised was less than $1 million.*

Quarterly dividends may be declared in an amount expressed in dollars per common share or could be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume-weighted average trading price of the Common Shares on the principal stock exchange on which the common shares are traded. The volume-weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares.

On February 28, 2018, the Board of Directors reinstated the quarterly common share dividends.

Common Share Dividends ($ millions)	**2018**		2017	
	Declared	Paid	Declared	Paid
	402	**276**	—	—

At December 31, 2018, Common Share dividends payable were $126 million (December 31, 2017 – nil).

Preferred Shares

The Company is authorized to issue an unlimited number of no par value preferred shares.

Cumulative Redeemable Preferred Shares	Number of Shares	Amount *($ millions)*
December 31, 2016	36,000,000	874
December 31, 2017	36,000,000	874
December 31, 2018	**36,000,000**	**874**

Cumulative Redeemable Preferred Shares Dividends *($ millions)*	**2018**		2017	
	Declared	Paid	Declared	Paid
Series 1 Preferred Shares	**6**	**8**	6	6
Series 2 Preferred Shares	**1**	**1**	1	1
Series 3 Preferred Shares	**12**	**14**	11	11
Series 5 Preferred Shares	**9**	**11**	9	9
Series 7 Preferred Shares	**7**	**9**	7	7
	35	**43**	34	34

At December 31, 2018, Preferred Share dividends payable were nil (December 31, 2017 - $9 million).

Holders of the Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 2.404 percent annually for a five year period ending March 31, 2021, as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the five-year Government of Canada bond yield plus 1.73 percent. Holders of Series 1 Preferred Shares have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"), subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter.

Holders of the Series 2 Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend that is reset every quarter for a five year period ending March 31, 2021, as and when declared by the Company's Board of Directors. The dividend rate applicable to the Series 2 Preferred Shares, for the three month period commencing September 30, 2018 but excluding December 31, 2018, was 3.239 percent based on the sum of the Government of Canada 90 day Treasury bill rate on August 21, 2018 plus 1.73 percent. Holders of Series 2 Preferred Shares have the right, at their option, to convert their shares into Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter.

Holders of the Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending December 31, 2019 as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"), subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

Holders of the Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every 5 years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"), subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent.

Holders of the Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every 5 years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every 5 years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

Stock Option Plan

Pursuant to the Incentive Stock Option Plan (the "Option Plan"), the Company may grant from time to time to executive officers and certain employees of the Company options to purchase common shares of the Company. The term of each option is five years, and vests one-third on each of the first three anniversary dates from the grant date. The Option Plan provides the option holder with the right to exercise the option to acquire one common share at the exercise price or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the grant date. When the stock option is surrendered to the Company, the cash payment is equal to the excess of the aggregate fair market value of the common shares able to be purchased pursuant to the vested and exercisable portion of such stock options on the date of surrender over the aggregate exercise price for those common shares pursuant to those stock options. The fair market value of common shares is calculated as the closing price of the common shares on the date on which board lots of common shares have traded immediately preceding the date a holder of the stock options provides notice to the Company that he or she wishes to surrender his or her stock options to the Company in lieu of exercise.

Included in accounts payable and accrued liabilities and other long-term liabilities in the consolidated balance sheets at December 31, 2018 was $11 million (December 31, 2017 – $21 million) representing the estimated fair value of options outstanding. The total expense recovery recognized in selling, general and administrative expenses in the consolidated statements of income for the Option Plan for the year ended December 31, 2018 was $3 million (December 31, 2017 – expense of $13 million). At December 31, 2018, the intrinsic value of stock options exercisable for cash was nil (December 31, 2017 – $12 million).

The following options to purchase common shares have been awarded to officers and certain other employees:

Outstanding and Exercisable Options	2018		2017	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**22,645**	**23.96**	25,459	26.26
Granted[1]	**5,610**	**17.21**	5,544	16.13
Exercised for common shares	**(2)**	**15.67**	—	—
Surrendered for cash	**(1,772)**	**15.82**	—	—
Expired or forfeited	**(6,514)**	**27.69**	(8,358)	25.62
Outstanding, end of year	**19,967**	**21.48**	22,645	23.96
Exercisable, end of year	**10,461**	**25.87**	12,946	28.91

(1) *Options granted during the year ended December 31, 2018 were attributed a fair value of $2.90 per option (2017 – $2.01) at grant date.*

Outstanding and Exercisable Options	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$14.20 - $29.99	16,061	18.55	2.90	6,555	21.30
$30.00 - $36.20	3,906	33.52	0.17	3,906	33.51
December 31, 2018	**19,967**	**21.48**	**2.37**	**10,461**	**25.87**

The fair value of the share options is estimated at each reporting date using the Black-Scholes option pricing model, taking into account the terms and conditions upon which the share options are granted and for the performance options, the current likelihood of achieving the specified target. The following table lists the assumptions used in the Black-Scholes option pricing model for the share options and performance options:

Black-Scholes Assumptions	December 31, 2018	December 31, 2017
	Tandem Options	Tandem Options
Dividend per option	**0.56**	0.72
Range of expected volatilities used *(percent)*	**16.8 - 44.4**	16.7 - 32.9
Range of risk-free interest rates used *(percent)*	**1.6 - 1.9**	0.9 - 1.9
Expected life of share options from vesting date *(years)*	**1.95**	1.95
Expected forfeiture rate *(percent)*	**8.9**	9.0
Weighted average exercise price	**22.46**	25.46
Weighted average fair value	**0.65**	1.15

The expected life of the share options is based on historical data and current expectations and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility over a period similar to the expected life of the options is indicative of future trends, which may also not necessarily be the actual outcome.

Performance Share Units

In February 2010, the Compensation Committee of the Board of Directors of the Company established the Performance Share Unit Plan for executive officers and certain employees of the Company. The term of each PSU is three years, and the PSU vests on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company's total shareholder return relative to a peer group of companies and achieving a ROCIU target set by the Company. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. Upon vesting, PSU holders receive a cash payment equal to the number of vested PSUs multiplied by the weighted average trading price of the Company's common shares for the five preceding trading days. As at December 31, 2018, the carrying amount of the liability relating to PSUs was $63 million (December 31, 2017 – $41 million). The total expense recognized in selling, general and administrative expenses in the consolidated statements of income for the PSUs for the year ended December 31, 2018 was $47 million (2017 – $32 million). The Company paid out $24 million (2017 – $15 million) for performance share units which vested in the year. The weighted average contractual life of the PSUs at December 31, 2018 was two years (December 31, 2017 – two years).

The number of PSUs outstanding was as follows:

Performance Share Units	2018	2017
Beginning of year	**8,361,918**	4,863,690
Granted	**6,108,430**	5,667,970
Exercised	**(1,354,316)**	(966,932)
Forfeited	**(1,509,388)**	(1,202,810)
Outstanding, end of year	**11,606,644**	8,361,918
Vested, end of year	**4,487,585**	2,262,954

Earnings per Share

Earnings per Share

($ millions)	2018	2017
Net earnings	**1,457**	786
Effect of dividends declared on preferred shares in the year	**(35)**	(34)
Net earnings – basic	**1,422**	752
Dilutive effect of accounting for stock options[1]	**(13)**	4
Net earnings – diluted	**1,409**	756
(millions)		
Weighted average common shares outstanding – basic	**1,005.1**	1,005.3
Effect of stock dividends declared in the year	**1.0**	—
Weighted average common shares outstanding – diluted	**1,006.1**	1,005.3
Earnings per share – basic *($/share)*	**1.41**	0.75
Earnings per share – diluted *($/share)*	**1.40**	0.75

(1) *For the year ended December 31, 2018, equity-settlement of stock options was used to calculate diluted earnings per share as it was considered more dilutive than cash-settlement (December 31, 2017 - cash settlement method was used). Stock-based compensation recovery was $3 million based on equity-settlement for the year ended December 31, 2018 (2017 – expense of $9 million). Stock-based compensation expense would have been $10 million based on cash-settlement for the year ended December 31, 2018 (2017 – $13 million).*

For the year ended December 31, 2018, 13 million tandem options (2017 – 23 million) were excluded from the calculation of diluted earnings per share as these options were anti-dilutive.

Note 20 Production, Operating and Transportation and Selling, General and Administrative Expenses

The following table summarizes production, operating and transportation expenses in the consolidated statements of income for the years ended December 31, 2018 and 2017:

Production, Operating and Transportation Expenses

($ millions)	2018	2017
Services and support costs	**1,039**	930
Salaries and benefits	**762**	664
Materials, equipment rentals and leases	**243**	248
Energy and utility	**405**	453
Licensing fees	**191**	200
Transportation	**24**	26
Other	**139**	158
Total production, operating and transportation expenses	**2,803**	2,679

The following table summarizes selling, general and administrative expenses in the consolidated statements of income for the years ended December 31, 2018 and 2017:

Selling, General and Administrative Expenses

($ millions)	2018	2017
Employee costs[1]	**332**	395
Stock-based compensation expense[2]	**44**	45
Contract services	**104**	100
Equipment rentals and leases	**39**	37
Maintenance and other	**135**	73
Total selling, general and administrative expenses	**654**	650

(1) *Employee costs are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.*

(2) *Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans.*

Note 21 Financial Items

Financial Items

($ millions)	2018	2017
Foreign exchange		
Non-cash working capital gains	**(3)**	(3)
Other foreign exchange gains (losses)	**17**	(3)
Net foreign exchange gains (losses)	**14**	(6)
Finance income	**64**	37
Finance expenses		
Long-term debt	**(320)**	(342)
Contribution payable *(note 11)*	**—**	(2)
Other	**(5)**	(4)
	(325)	(348)
Interest capitalized(1)	**108**	68
	(217)	(280)
Accretion of asset retirement obligations *(note 16)*	**(97)**	(112)
Finance expenses	**(314)**	(392)
Total Financial Items	**(236)**	(361)

(1) *Interest capitalized on project costs is calculated using the Company's annualized effective interest rate of 5 percent (2017 – 5 percent).*

Note 22 Pensions and Other Post-employment Benefits

The Company currently provides defined contribution pension plans for all qualified employees and two other post-employment benefit plans to its retirees. The other post-employment benefit plans provide certain retired employees with health care and dental benefits. The Company also maintains two defined benefit pension plans, which are closed to new entrants. The defined benefit pension plans provide pension benefits to certain employees based on years of service and final average earnings. The amount and timing of funding of these plans is subject to the funding policy as approved by the Board of Directors.

The measurement date of all plan assets and the accrued benefit obligations was December 31, 2018. The Company is required to file an actuarial valuation of its defined benefit pension with the provincial or state regulator at least every three years. The most recent actuarial valuation was December 31, 2016 for the Canadian defined benefit plan and December 31, 2018 for the U.S defined benefit plan. The most recent actuarial valuation was April 30, 2018 for the Canadian Other Post-employment benefit plan. The most recent actuarial valuation of the U.S. Other Post-employment benefit plan was January 18, 2019.

Defined Contribution Pension Plan

During the year ended December 31, 2018, the Company recognized a $54 million expense (2017 – $46 million) for the defined contribution plan and the two U.S. 401(k) plans in net earnings.

Defined Benefit Pension Plans ("DB Pension Plan") and Other Post-employment Benefit Plans ("OPEB Plans")

Defined Benefit Obligations	DB Pension Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Beginning of year	**76**	178	**244**	213
Current service cost	**1**	1	**11**	15
Interest cost	**3**	4	**8**	8
Benefits paid	**(2)**	(9)	**(4)**	(4)
Settlements	**—**	(140)	**—**	—
Increase due to business combinations[1]	**—**	34	**—**	—
Remeasurements				
Actuarial (gain) loss – experience	**2**	3	**(13)**	—
Actuarial loss – financial assumptions	**(4)**	5	**(45)**	12
Effect of changes in foreign exchange rates	**3**	—	**(2)**	—
End of year	**79**	76	**199**	244

[1] *The Superior Refinery DB pension plan was transferred from Calumet GP. LLC to Husky Energy Inc. effective November 2017.*

Fair Value of Plan Assets	DB Pension Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Beginning of year	**67**	183	**—**	—
Contributions by employer	**1**	6	**2**	—
Benefits paid	**(2)**	(9)	**(2)**	—
Interest income	**2**	4	**—**	—
Return on plan assets greater than discount rate	**—**	4	**—**	—
Settlements	**—**	(148)	**—**	—
Increase due to business combinations[1]	**—**	27	**—**	—
Effect of changes in foreign exchange rates	**3**	—	**—**	—
End of year	**71**	67	**—**	—

[1] *The Superior Refinery DB pension plan was transferred from Calumet GP. LLC to Husky Energy Inc. effective November 2017. Please refer to Note 9 for business combination.*

Funded status	DB Pension Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Net asset (liability)	**(8)**	(9)	**(199)**	(244)

The Company has accrued the total net liability for the DB Pension Plan and the OPEB Plans in the consolidated balance sheets in other long-term liabilities.

On July 27, 2017, the Company completed a series of transactions related to the Canadian DB Pension Plan. The most recent actuarial valuation at the transaction date was at December 31, 2016. Defined benefit assets and accrued obligations were remeasured immediately prior to the transactions. DB Pension Plan assets of $148 million, including a one-time cash contribution by the Company of $5 million, were used to settle $140 million of the defined benefit obligation related to the inactive plan members. This resulted in the Company recognizing a $8 million loss on settlement in Other – net expense.

Furthermore, as part of a risk management strategy the Company also purchased a $48 million annuity, on July 27, 2017, to offset the related $42 million defined benefit obligation for the active plan members. This resulted in a $3 million actuarial loss (net of tax of $1 million) on plan assets recorded in other comprehensive income in 2017.

The Company continued to accrue service costs for the active plan members and the contribution to the plan for 2018.

In November 2017, the Company also acquired a small defined benefit pension plan for the employees of the Superior Refinery which is closed to new entrants.

The composition of the DB Pension Plan assets at December 31, 2018 and 2017 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	**2018**	2017
Money market type funds	—	**5.0**	0.2
Equity securities	—	**—**	—
Debt securities	100	**95.0**	99.8

The following table summarizes amounts recognized in net earnings and OCI for the DB Pension Plans and the OPEB Plans for the years ended December 31, 2018 and 2017:

	DB Pension Plan		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Amounts recognized in net earnings				
Current service cost	**1**	1	**11**	15
Past service cost	**—**	1	**—**	—
Net Interest cost	**1**	—	**8**	8
Settlement loss	**—**	8	**—**	—
Benefit cost	**2**	10	**19**	23
Remeasurements				
Actuarial loss (gain) due to liability experience	**2**	3	**(13)**	—
Actuarial loss (gain) due to liability assumption changes	**(4)**	5	**(45)**	12
Gain on plan assets	**—**	(4)	**—**	—
Remeasurement effects recognized in OCI	**(2)**	4	**(58)**	12

The following long-term assumptions were used to estimate the value of the defined benefit obligations, the plan assets and the OPEB Plans:

Assumptions

	DB Pension Plan		OPEB Plans	
(percent)	**2018**	2017	**2018**	2017
Discount rate for benefit expense and obligation	**3.4 - 3.6**	3.4 - 3.5	**3.4 - 3.7**	3.4 - 3.9
Rate of compensation expense	**N/A**	3.5	**N/A**	N/A

The average health care cost trend rate used for the benefit expense for the Canadian OPEB Plan was 6.5 percent for 2018, grading 0.5 percent per year for 3 years to 5.0 percent in 2021 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 6.0 percent for 2018, 2019 and 2020, grading 0.5 percent per year for 3 years to 5.0 percent in 2022 and thereafter.

The average health care cost trend rate used for the benefit expense for the U.S. OPEB Plan was 6.0 percent for 2018, grading 0.25 percent per year for 5 years to 5.0 percent per year in 2022 and thereafter. The average health care cost trend rate used for the obligation related to the U.S. OPEB Plan was 6.5 percent for 2018, grading 0.25 percent per year for 6 years to 5.0 percent in 2026 and thereafter.

The sensitivity of the defined benefit and OPEB obligations to changes in relevant actuarial assumption is shown below:

Sensitivity Analysis

	DB Pension Plan		OPEB Plans	
($ millions)	1% increase	1% decrease	1% increase	1% decrease
Discount rate	(9)	11	(33)	43
Health care cost trend rate	N/A	N/A	32	(25)

Note 23 Cash Flows – Change in Non-cash Working Capital

Non-cash Working Capital

($ millions)	2018	2017
Decrease (increase) in non-cash working capital		
Accounts receivable	**127**	(329)
Inventories	**393**	(264)
Prepaid expenses	**30**	(38)
Accounts payable and accrued liabilities	**(65)**	1,269
Change in non-cash working capital	**485**	638
Relating to:		
Operating activities	**130**	398
Financing activities	**120**	—
Investing activities	**235**	240

Note 24 Financial Instruments and Risk Management

Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, derivatives, portions of other assets and other long-term liabilities. Derivative instruments are measured at fair value through profit or loss ("FVTPL"). The Company's remaining financial instruments are measured at amortized cost. For financial instruments measured at amortized cost, the carrying values approximate their fair value with the exception of long-term debt.

The following table summarizes the Company's financial instruments that are carried at fair value in the consolidated balance sheets:

Financial Instruments at Fair Value

($ millions)	December 31, 2018	December 31, 2017
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**(9)**	(13)
Crude oil[(2)]	**89**	(57)
Foreign currency contracts – FVTPL		
Foreign currency forwards	**(1)**	1
Other assets – FVTPL	**1**	1
Derivatives designated as a cash flow hedge - forward starting swaps	**(14)**	—
Hedge of net investment[(3)(4)]	**(846)**	(584)
End of year	**(780)**	(652)

(1) *Natural gas contracts includes a $10 million decrease at December 31, 2018 (December 31, 2017 – $3 million decrease) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $15 million at December 31, 2018 (December 31, 2017 – $5 million).*

(2) *Crude oil contracts includes a $67 million increase at December 31, 2018 (December 31, 2017 – $5 million increase) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $185 million at December 31, 2018 (December 31, 2017 – $232 million).*

(3) *Hedging instruments are presented net of tax.*

(4) *Represents the translation of the Company's U.S. dollar denominated long-term debt designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.*

The fair value of long-term debt represents the present value of future cash flows associated with the debt. Market information, such as treasury rates and credit spreads, are used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. At December 31, 2018, the carrying value of the Company's long-term debt was $5.5 billion and the estimated fair value was $5.7 billion (December 31, 2017 – carrying value of $5.2 billion, estimated fair value of $5.6 billion).

All financial assets and liabilities are classified as Level 2 fair value measurements. During the year ended December 31, 2018, there were no transfers between Level 1 and Level 2 fair value measurements, and no transfers into or out of Level 3 fair value measurements.

Risk Management Overview

The Company is exposed to risks related to the volatility of commodity prices, foreign exchange rates and interest rates. It is also exposed to financial risks related to liquidity, credit and contract risks. Risk management strategies and policies are employed to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels. Responsibility for the oversight of risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

Responsibility for risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

a) Market Risk

i) Commodity Price Risk Management

The Company uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production, and it also uses firm commitments for the purchase or sale of crude oil and natural gas. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable, inventory, other assets, accounts payable and accrued liabilities and other long-term liabilities. All derivatives are measured at fair value through profit or loss other than non-financial derivative contracts that meet the Company's own use requirements.

At December 31, 2018, the Company was party to crude oil purchase and sale derivative contracts to mitigate its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company was also party to third party physical natural gas purchase and sale derivative contracts in order to mitigate commodity price fluctuations. For the year ended December 31, 2018, the net unrealized gain recognized on the derivative contracts was $150 million (2017 - net unrealized loss of $56 million).

II) Foreign Exchange Risk Management

The Company's results are affected by the exchange rates between various currencies and the Company's functional currency in Canadian dollars. As the majority of the Company's revenues are denominated in U.S. dollars or based upon a U.S. benchmark price, fluctuations in the value of the Canadian dollar relative to the U.S. dollar may affect revenues significantly. To limit the exposure to foreign exchange risk, the Company hedges against these fluctuations by entering into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars.

Foreign exchange fluctuations will result in a change in value of the U.S. dollar denominated debt and related finance expense when expressed in Canadian dollars. At December 31, 2018, the Company had designated US$2.7 billion denominated debt as a hedge of the Company's selected net investments in its foreign operations with a U.S. dollar functional currency (December 31, 2017 – US$2.7 billion). For the year ended December 31, 2018, the unrealized loss arising from the translation of the debt was $262 million (December 31, 2017 – unrealized gain of $243 million), net of tax recovery of $41 million (December 31, 2017 – expense of $38 million), which was recorded in hedge of net investment within OCI.

III) Interest Rate Risk Management

The Company is exposed to fluctuations in short-term interest rates as the Company maintains a portion of its debt capacity in revolving and floating rate bank facilities and commercial paper and invests surplus cash in short-term debt instruments and money market instruments. The Company is also exposed to interest rate risk when fixed rate debt instruments are maturing and require refinancing or when new debt capital needs to be raised.

By maintaining a mix of both fixed and floating rate debt, the Company mitigates some of its exposure to interest rate changes. The optimal mix maintained will depend on market conditions. The Company may also enter into fair value or cash flow hedges using interest rate swaps.

On December 4, 2018, the Company entered into cash flow hedges using forward interest rate swaps to fix the underlying U.S. $500 million 10-year note fixed rate to December 15, 2019. There was no ineffective portion as at December 31, 2018. For the year ended December 31, 2018, the unrealized loss arising from the recognition of the swaps was $11 million (December 31, 2017 - nil), net of tax recovery of $3 million, which was recorded in OCI.

The forward starting swaps have the following terms and fair value as at December 31, 2018.

Forward Starting Swaps ($ millions)	As at December 31, 2018		
	Swap Rate[1]	Notional Amount (U.S. $ millions)	Fair Value ($ million)
Swap Maturity			
December 15, 2029	**2.999%**	**250**	**(7)**
December 15, 2029	**3.000%**	**250**	**(7)**

[1] *Weighted average rate.*

At December 31, 2018, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $13 million (December 31, 2017 – $15 million), net of tax of $4 million (December 31, 2017 – net of tax of $5 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an offset to finance expense of $2 million for the year ended December 31, 2018 (December 31, 2017 – $2 million).

Offsetting Financial Assets and Liabilities

The tables below outline the financial assets and financial liabilities that are subject to set-off rights and related arrangements, and the effect of those rights and arrangements on the consolidated balance sheets:

Offsetting Financial Assets and Liabilities ($ millions)	As at December 31, 2018		
	Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	**188**	**(120)**	**68**
Normal purchase and sale agreements	**625**	**(335)**	**290**
End of year	**813**	**(455)**	**358**
Financial Liabilities			
Financial derivatives	**(107)**	**62**	**(45)**
Normal purchase and sale agreements	**(756)**	**307**	**(449)**
End of year	**(863)**	**369**	**(494)**

Offsetting Financial Assets and Liabilities ($ millions)	As at December 31, 2017		
	Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	150	(111)	40
Normal purchase and sale agreements	639	(280)	359
End of year	789	(391)	399
Financial Liabilities			
Financial derivatives	(246)	122	(123)
Normal purchase and sale agreements	(933)	353	(581)
End of year	(1,179)	475	(704)

Market Risk Sensitivity Analysis

A sensitivity analysis for commodities, foreign currency exchange and interest rate risks has been calculated by increasing or decreasing commodity prices, foreign currency exchange rates or interest rates, as appropriate. These sensitivities represent the increase or decrease in earnings before income taxes resulting from changing the relevant rates, with all other variables held constant. These sensitivities have only been applied to financial instruments held at fair value. The Company's process for determining these sensitivities has not changed during the year.

Commodity Price Risk[1]

($ millions)	10% price increase	10% price decrease
Crude oil price	26	(26)
Natural gas price	(9)	9

Foreign Exchange Rate[2]

($ millions)	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar	1	(1)

Interest Rate[3]

($ millions)	100 basis point increase	100 basis point decrease
LIBOR	61	(61)

(1) *Based on average crude oil and natural gas market prices as at December 31, 2018.*
(2) *Based on the U.S./Canadian dollar exchange rate as at December 31, 2018.*
(3) *Based on the U.S. LIBOR as at December 31, 2018.*

b) Financial Risk

i) Liquidity Risk Management

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and capacity to raise capital from various debt and equity capital markets under its shelf prospectuses. The Company prepares annual capital expenditure budgets, which are monitored and updated as required. In addition, the Company requires authorizations for expenditures on projects, which assists with the management of capital.

Since the Company operates in the Upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt. The Company's Upstream capital programs are funded principally by cash provided from operating activities and issuances of debt and equity. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow of maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. Occasionally, the Company will economically hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company had the following available credit facilities as at December 31, 2018:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1] *(note 13)*	**900**	**461**
Syndicated bank facilities[2] *(note 15)*	**4,000**	**3,800**
End of year	**4,900**	**4,261**

(1) *Consists of demand credit facilities.*
(2) *Commercial paper outstanding is supported by the Company's Syndicated credit facilities.*

In addition to the credit facilities listed above, the Company had unused capacity under the Canadian Shelf Prospectus of $3.0 billion and unused capacity under the U.S Shelf Prospectus and related U.S registration statement of US$3.0 billion. The ability of the Company to raise additional capital utilizing these Shelf Prospectuses is dependent on market conditions.

The Company believes it has sufficient funding through the use of these facilities and access to the capital markets to meet its future capital requirements.

ii) Credit and Contract Risk Management

Credit and contract risk represent the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms. The Company actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective. The Company's accounts receivables are broad based with customers in the energy industry and midstream and end user segments and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company had one external customer that constituted more than 10 percent of gross revenues during the years ended December 31, 2018 and December 31, 2017. Sales to this customer were approximately $4.2 billion for the year ended December 31, 2018 (December 31, 2017 – $3.3 billion).

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than three months. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amounts of cash and cash equivalents, accounts receivable and restricted cash represent the Company's maximum credit exposure.

The Company's accounts receivable was aged as follows at December 31, 2018:

Accounts Receivable Aging

($ millions)	**December 31, 2018**
Current	**1,140**
Past due (1 – 30 days)	**139**
Past due (31 – 60 days)	**42**
Past due (61 – 90 days)	**16**
Past due (more than 90 days)	**57**
Provision for expected credit losses	**(39)**
	1,355

The Company recognizes a valuation provision when collection of accounts receivable is in doubt. Accounts receivable are impaired directly when collection of accounts receivable is no longer expected. For the year ended December 31, 2018, the Company wrote off $3 million (December 31, 2017 – $1 million) of uncollectible receivables.

Note 25 Related Party Transactions

The following table lists the Company's significant subsidiaries and jointly-controlled entities and their respective places of incorporation, continuance or organization, as the case may be, and the Company's percentage equity interest (to the nearest whole number) as at December 31, 2018. All of the entities listed below, except as otherwise indicated, are 100 percent beneficially owned, or controlled or directed, directly or indirectly, by the Company.

Significant Subsidiaries and Joint Operations	%	Jurisdiction
Husky Oil Operations Limited	100	Alberta
Husky Energy International Corporation	100	Alberta
Lima Refining Company	100	Delaware
Husky Marketing and Supply Company	100	Delaware
Husky Oil Limited Partnership	100	Alberta
Husky Terra Nova Partnership	100	Alberta
Husky Downstream General Partnership	100	Alberta
Husky Energy Marketing Partnership	100	Alberta
Sunrise Oil Sands Partnership	50	Alberta
BP-Husky Refining LLC	50	Delaware

Each of the related party transactions described below was made on terms equivalent to those that prevail in arm's length transactions.

The Company performs management services as the operator of the assets held by HMLP for which it recovers shared service costs. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to PAH and CKI, which are affiliates of one of the Company's principal shareholders. For the year ended December 31, 2018, the Company charged HMLP $448 million (December 31, 2017 – $412 million) related to construction costs and management services. For the year ended December 31, 2018, the Company had purchases from HMLP of $200 million (December 31, 2017 – $203 million) related to the use of the pipeline for the Company's blending activities, transportation and storage activities, received distributions of $139 million (December 31, 2017 – $25 million) and paid capital contributions of $40 million (December 31, 2017 – $17 million). At December 31, 2018, the Company had $140 million due from HMLP, of which nil relates to unbilled revenue from construction contracts on the percentage of completion method (December 31, 2017 – $67 million and $23 million, respectively).

Key management includes Directors (executive and non-executive), Executive Officers and Senior Vice – Presidents of the Company. The amounts disclosed in the table below are the amounts recognized as an expense during the reporting period related to key management personnel:

Compensation of Key Management Personnel

($ millions)	**2018**	2017
Short-term employee benefits[(1)]	**17**	16
Stock-based compensation[(2)]	**33**	31
	50	47

(1) Short-term employee benefits are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.

(2) Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans.

Note 26 Commitments and Contingencies

At December 31, 2018, the Company had commitments that require the following minimum future payments, which are not accrued in the consolidated balance sheets:

Minimum Future Payments for Commitments

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Operating leases(1)	233	504	1,186	1,923
Firm transportation agreements(1)	497	2,066	4,013	6,576
Unconditional purchase obligations(2)	1,620	3,656	4,822	10,098
Lease rentals and exploration work agreements	49	246	930	1,225
Obligations to fund equity investee(3)	53	293	395	741
	2,452	6,765	11,346	20,563

(1) *Included in operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of $1.1 billion and $1.9 billion respectively with HMLP.*

(2) *Includes processing services, distribution services, insurance premiums, drilling services, natural gas purchases and the purchase of refined petroleum products.*

(3) *Equity investee refers to the Company's investment in Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

The Company has income tax and royalty filings that are subject to audit and potential reassessment. The findings may impact the liabilities of the Company. The final results are not reasonably determinable at this time, and management believes that it has adequately provided for current and deferred income taxes.

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters would have a material adverse impact on its financial position, results of operations or liquidity.

Note 27 Capital Disclosures

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt which was $25.4 billion as at December 31, 2018 (December 31, 2017 – $23.4 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations. Debt to capital employed is defined as long-term debt, long-term debt due within one year, and short-term debt divided by capital employed which is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity. Debt to funds from operations is defined as long-term debt, long-term debt due within one year and short-term debt divided by funds from operations which is equal to cash flow – operating activities plus change in non-cash working capital.

The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At December 31, 2018, debt to capital employed was 22.7 percent (December 31, 2017 – 23.2 percent) and debt to funds from operations was 1.4 times (December 31, 2017 – 1.6 times), within the Company's targets. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however, the syndicated credit facilities include a debt to capital covenant, calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2018, and assessed the risk of non-compliance to be low.

There were no changes in the Company's approach to capital management from the previous year.

Note 28 Subsequent Event

On January 8, 2019, the Company announced its intention to market and potentially sell its Prince George Refinery and Retail and Commercial Network. An estimate of the financial impact cannot be made at this time.

On January 16, 2019, the Company announced that its offer to acquire all of the outstanding common shares of MEG Energy Corp. expired, as the minimum tender threshold was not satisfied, and the Company decided not to extend its offer.

Supplemental Financial and Operating Information

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2018**	2017	2016	2015	2014	2013	2012[(1)]	2011[(1)]	2010[(2)(3)]	2009[(2)(3)]
Financial Highlights										
Gross Revenues and Marketing and Other	**22,587**	18,946	13,224	16,801	25,122	24,181	22,948	22,829	18,085	15,935
Net earnings (loss)	**1,457**	786	922	(3,850)	1,258	1,829	2,022	2,224	947	1,416
Earnings (loss) per share										
Basic	**1.41**	0.75	0.88	(3.95)	1.26	1.85	2.06	2.40	1.11	1.67
Diluted	**1.40**	0.75	0.88	(4.01)	1.20	1.85	2.06	2.34	1.05	1.67
Capital expenditures[(4)]	**3,578**	2,220	1,705	3,005	5,023	5,028	4,701	4,618	3,571	2,797
Total debt[(8)]	**5,747**	5,440	5,339	6,756	5,292	4,119	3,918	3,911	4,187	3,229
Debt to capital employed *(percent)*[(5)]	**22.7**	23.2	23.2	28.9	20.0	17.0	17.0	18.0	22.0	18.0
Upstream										
Daily production, before royalties										
Crude oil & NGLs *(mboe/day)*	**214.7**	233.0	228.6	230.9	236.6	226.5	209.2	211.3	202.6	216.2
Natural gas *(mmcf/day)*	**507.0**	539.1	559.9	689.0	621.0	512.7	554.0	607.0	506.8	541.7
Total production *(mboe/day)*	**299.2**	322.9	321.2	345.7	340.1	312.0	301.5	312.5	287.1	306.5
Total proved reserves, before royalties *(mmboe)*[(6)]	**1,471**	1,301	1,224	1,324	1,279	1,265	1,192	1,172	1,081	933
Downstream										
Upgrading										
Synthetic crude oil sales *(mbbls/day)*	**52.9**	49.8	55.2	51.1	53.3	50.5	60.4	55.3	54.1	61.8
Upgrading differential *($/bbl)*	**29.05**	18.66	20.74	18.66	21.80	29.14	22.34	27.34	14.52	11.89
Canadian Refined Products										
Fuel sales *(million of litres/day)*[(7)]	**7.7**	7.3	6.6	7.6	8.0	8.1	8.7	9.5	8.2	7.6
Refinery throughput										
Prince George Refinery *(mbbls/day)*	**10.7**	11.2	9.4	10.7	11.7	10.3	11.1	10.6	10.0	10.3
Lloydminster Refinery *(mbbls/day)*	**27.1**	26.8	27.8	28.1	28.8	26.4	28.3	28.1	27.8	24.1
U.S. Refining and Marketing										
Refinery throughput										
Lima Refinery *(mbbls/day)*	**151.1**	172.2	138.2	136.1	141.6	149.4	150.0	144.3	136.6	114.6
BP-Husky Toledo Refinery *(mbbls/day)*[(9)]	**71.1**	76.6	62.2	68.2	63.2	65.0	60.6	63.9	64.4	64.9
Superior Refinery *(mbbls/day)*[(10)]	**11.7**	5.5	—	—	—	—	—	—	—	—
Refining and marketing margin *(U.S. $/bbl crude throughput)*[(11)]	**13.03**	11.44	8.94	10.09	9.37	15.06	17.48	17.60	7.29	11.37

(1) *Gross revenues and U.S. refining margin have been recast for 2012 and 2011 to reflect a change in the classification of certain trading transactions.*
(2) *Results reported for 2010 and previous years have not been adjusted for the change in presentation of the former Midstream.*
(3) *Results are reported in accordance with previous Canadian GAAP. Certain reclassifications have been made to conform with current presentation.*
(4) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period. Includes Exploration and Production assets acquired through acquisition, but excludes assets acquired through corporate acquisition.*
(5) *Debt to capital employed is a non-GAAP measures. Refer to Section 9.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.*
(6) *Total proved reserves, before royalties for 2010 onwards were prepared in accordance with the Canadian Securities Administrators' National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Prior to 2010, reserves were prepared in accordance with the rules of the United States Securities and Exchange Commission guidelines and the United States Financial Accounting Standards Board. Refer to Section 9.2 of the Management's Discussion and Analysis for a discussion.*
(7) *Fuel sales have been recast to exclude non-retail products, results reported for 2010 and previous years have not been adjusted for the change in presentation.*
(8) *Total debt is a non-GAAP measure that equals the sum of long-term debt, long-term debt due within one year and short-term debt. Refer to Section 9.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.*
(9) *BP-Husky Toledo Refinery throughput was revised in the first quarter of 2016 to reflect total throughput. Prior periods reflected crude throughput only and 2015 has been restated to conform with current presentation. Results reported for 2014 and prior have not been adjusted for the change in presentation.*
(10) *Superior Refinery was acquired in November 2017.*
(11) *U.S. refining margin has been revised to include impact of U.S. product marketing margin. Results reported for 2016 and prior have not been adjusted for the change in presentation.*

Segmented Financial Information

	Upstream										Downstream				
	Exploration and Production[1]					Infrastructure and Marketing					Upgrading				
($ millions)	**2018**	2017	2016	2015	2014	**2018**	2017	2016	2015	2014	**2018**	2017	2016	2015	2014
Year ended December 31															
Gross revenues	**4,330**	4,978	4,036	5,374	8,634	**2,211**	1,976	955	1,264	2,202	**1,750**	1,440	1,324	1,319	2,212
Royalties	**(335)**	(363)	(305)	(432)	(1,030)	**—**	—	—	—	—	**—**	—	—	—	—
Marketing and other	**—**	—	—	—	—	**668**	(40)	(88)	38	70	**—**	—	—	—	—
Revenues, net of royalties	**3,995**	4,615	3,731	4,942	7,604	**2,879**	1,936	867	1,302	2,272	**1,750**	1,440	1,324	1,319	2,212
Expenses															
Purchase of crude oil and products	**—**	—	32	41	96	**2,087**	1,855	857	1,123	2,056	**928**	983	808	922	1,676
Production, operating and transportation expenses	**1,527**	1,650	1,760	2,076	2,172	**23**	13	20	37	32	**195**	197	168	169	180
Selling, general and administrative expenses	**296**	265	232	237	253	**5**	4	5	7	8	**7**	9	4	4	9
Depletion, depreciation, amortization and impairment	**1,811**	2,237	1,815	7,993	3,434	**—**	2	13	25	25	**123**	99	103	106	108
Exploration and evaluation expenses	**149**	146	188	447	214	**—**	—	—	—	—	**—**	—	—	—	—
Loss (gain) on sale of assets	**(2)**	(42)	(192)	(17)	(39)	**—**	1	(1,439)	—	—	**—**	—	—	—	—
Other – net	**(120)**	6	53	(34)	(21)	**2**	(8)	(3)	(5)	(2)	**—**	—	(1)	(11)	11
Total Expenses	**3,661**	4,262	3,888	10,743	6,109	**2,117**	1,867	(547)	1,187	2,119	**1,253**	1,288	1,082	1,190	1,984
Earnings (loss) from operating activities	**334**	353	(157)	(5,801)	1,495	**762**	69	1,414	115	153	**497**	152	242	129	228
Share of equity investment gain (loss)	**51**	12	(1)	(5)	(6)	**18**	49	16	—	—	**—**	—	—	—	—
Net financial items	**(97)**	(126)	(140)	(139)	(152)	**—**	—	—	—	—	**(1)**	(1)	(1)	(1)	(1)
Earnings (loss) before income tax	**288**	239	(298)	(5,945)	1,337	**780**	118	1,430	115	153	**496**	151	241	128	227
Current income taxes	**(484)**	(34)	(100)	(41)	386	**354**	—	—	222	99	**168**	63	—	(17)	47
Deferred income taxes	**549**	99	19	(1,566)	(41)	**(141)**	32	122	(191)	(60)	**(33)**	(22)	66	52	12
Total income tax provision (recovery)	**65**	65	(81)	(1,607)	345	**213**	32	122	31	39	**135**	41	66	35	59
Net earnings (loss)	**223**	174	(217)	(4,338)	992	**567**	86	1,308	84	114	**361**	110	175	93	168
Total assets as at December 31	**19,175**	17,920	19,098	21,103	26,035	**1,301**	1,364	1,582	1,699	1,969	**1,149**	1,263	1,076	1,141	1,243

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*
(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

Downstream										Corporate and Eliminations[2]					Total				
Canadian Refined Products					U.S. Refining and Marketing														
2018	2017	2016	2015	2014	**2018**	2017	2016	2015	2014	**2018**	2017	2016	2015	2014	**2018**	2017	2016	2015	2014
3,412	2,787	2,301	2,886	4,020	**11,770**	9,355	5,995	7,345	10,663	**(1,554)**	(1,550)	(1,299)	(1,425)	(2,679)	**21,919**	18,986	13,312	16,763	25,052
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**(335)**	(363)	(305)	(432)	(1,030)
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**668**	(40)	(88)	38	70
3,412	2,787	2,301	2,886	4,020	**11,770**	9,355	5,995	7,345	10,663	**(1,554)**	(1,550)	(1,299)	(1,425)	(2,679)	**22,252**	18,583	12,919	16,369	24,092
2,760	2,219	1,770	2,281	3,319	**10,334**	8,059	5,188	6,455	9,941	**(1,554)**	(1,550)	(1,299)	(1,425)	(2,679)	**14,555**	11,566	7,356	9,397	14,409
265	256	241	238	263	**795**	563	535	474	472	**(2)**	—	—	—	—	**2,803**	2,679	2,724	2,994	3,119
47	53	43	31	44	**22**	15	13	10	9	**277**	304	247	53	139	**654**	650	544	342	462
115	111	102	103	102	**450**	354	342	333	268	**92**	79	87	84	73	**2,591**	2,882	2,462	8,644	4,010
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**149**	146	188	447	214
(2)	(5)	(3)	(5)	(1)	**—**	—	—	—	4	**—**	—	—	—	—	**(4)**	(46)	(1,634)	(22)	(36)
(1)	(1)	(10)	1	1	**(464)**	(21)	(176)	(236)	(4)	**(8)**	6	110	(2)	(5)	**(591)**	(18)	(27)	(287)	(20)
3,184	2,633	2,143	2,649	3,728	**11,137**	8,970	5,902	7,036	10,690	**(1,195)**	(1,161)	(855)	(1,290)	(2,472)	**20,157**	17,859	11,613	21,515	22,158
228	154	158	237	292	**633**	385	93	309	(27)	**(359)**	(389)	(444)	(135)	(207)	**2,095**	724	1,306	(5,146)	1,934
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**69**	61	15	(5)	(6)
(12)	(12)	(7)	(6)	(5)	**(14)**	(14)	(3)	(3)	(3)	**(112)**	(208)	(220)	(71)	17	**(236)**	(361)	(371)	(220)	(144)
216	142	151	231	287	**619**	371	90	306	(30)	**(471)**	(597)	(664)	(206)	(190)	**1,928**	424	950	(5,371)	1,784
100	45	—	6	80	**9**	2	—	15	1	**(72)**	(79)	99	121	104	**75**	(3)	(1)	306	717
(42)	(7)	41	55	(7)	**129**	135	33	(106)	(12)	**(66)**	(596)	(252)	(71)	(83)	**396**	(359)	29	(1,827)	(191)
58	38	41	61	73	**138**	137	33	(91)	(11)	**(138)**	(675)	(153)	50	21	**471**	(362)	28	(1,521)	526
158	104	110	170	214	**481**	234	57	397	(19)	**(333)**	78	(511)	(256)	(211)	**1,457**	786	922	(3,850)	1,258
1,431	1,548	1,410	1,448	1,676	**8,566**	7,580	7,017	6,784	5,788	**3,603**	3,252	2,077	881	2,137	**35,225**	32,927	32,260	33,056	38,848

Upstream Operating Information

	2018	2017	2016	2015	2014
Daily Production, before royalties					
Light & Medium crude oil *(mbbls/day)*	**30.8**	51.4	63.1	80.5	91.2
NGL *(mbbls/day)*[(3)]	**22.9**	18.1	14.0	18.2	14.0
Heavy crude oil *(mbbls/day)*	**36.8**	44.4	54.1	69.1	76.8
Bitumen *(mbbls/day)*[(3)]	**124.2**	119.1	97.4	63.1	54.6
	214.7	233.0	228.6	230.9	236.6
Natural gas *(mmcf/day)*	**507.0**	539.1	555.9	689.0	621.0
Total production *(mboe/day)*	**299.2**	322.9	321.2	345.7	340.1
Average sales prices					
Light & Medium crude oil *($/bbl)*	**83.71**	67.36	52.40	57.55	96.59
NGL *($/bbl)*[(3)]	**55.72**	44.18	38.01	45.88	72.61
Heavy crude oil *($/bbl)*	**39.26**	43.38	30.50	37.16	71.91
Bitumen *($/bbl)*	**30.17**	38.20	27.63	34.47	70.57
Natural gas *($/mcf)*[(3)]	**6.64**	5.52	4.40	5.80	5.99
Operating costs *($/boe)*	**14.00**	13.93	14.04	15.14	16.12
Operating netbacks[(1)(2)(3)]					
Light & Medium crude oil *($/bbl)*	**45.44**	39.83	23.82	29.40	59.63
NGL *($/bbl)*	**39.53**	27.05	22.99	32.10	50.01
Heavy crude oil *($/bbl)*	**7.41**	15.33	9.25	14.56	41.95
Bitumen *($/bbl)*	**16.65**	24.85	15.21	15.41	51.17
Natural gas *($/mcf)*	**4.99**	3.67	2.51	3.93	3.79

(1) *The operating netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. Operating netback is a non-GAAP measure. Refer to Section 9.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.*

(2) *Includes associated co-products converted to boe.*

(3) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*

Supplemental Upstream Operating Statistics

Operating Netback Analysis[1]	2018	2017	2016
Upstream			
Crude Oil Equivalent *($/boe)*[2]			
Sales volume *(mboe/day)*	**299.2**	322.9	321.2
Gross revenue *($/boe)*[6]	**41.50**	42.47	33.08
Royalties *($/boe)*	**3.30**	3.07	2.60
Production and operating costs *($/boe)*[6]	**14.00**	13.93	14.04
Offshore transportation *($/boe)*[3]	**0.22**	0.22	0.25
Operating netback *($/boe)*	**23.98**	25.25	16.19
Depletion, depreciation, amortization and impairment *($/boe)*	**16.99**	19.08	15.45
Administration expenses and other *($/boe)*	**3.57**	3.13	2.62
Earnings (loss) before taxes *($/boe)*	**3.42**	3.04	(1.88)
Operating netbacks by commodity			
Crude Oil & NGL's Total[7]			
Sales volume *(mboe/day)*	**214.7**	233.0	228.6
Gross revenue *($/boe)*[6]	**42.16**	46.09	35.78
Royalties *($/boe)*	**3.92**	3.92	3.36
Production and operating costs *($/boe)*[6]	**16.30**	15.36	15.42
Offshore transportation *($/boe)*[3]	**0.30**	0.31	0.36
Operating netback *($/boe)*	**21.64**	26.50	16.64
Natural Gas Total[7]			
Sales volume *(mmcf/day)*	**507.0**	539.1	555.9
Gross revenue *($/mcf)*[7]	**6.64**	5.52	4.40
Royalties *($/mcf)*	**0.29**	0.15	0.12
Production and operating costs *($/mcf)*[6]	**1.36**	1.70	1.77
Operating netback *($/mcf)*	**4.99**	3.67	2.51
Thermal Development			
Lloydminster Thermal			
Bitumen			
Sales volumes *(mbbls/day)*	**76.8**	77.1	65.5
Gross revenue *($/bbl)*[6]	**35.39**	40.53	30.22
Royalties *($/bbl)*	**2.41**	2.76	1.98
Production and operating costs *($/bbl)*[6]	**10.54**	10.21	8.72
Operating netback *($/bbl)*	**22.44**	27.56	19.52
Tucker Thermal			
Bitumen			
Sales volumes *(mbbls/day)*	**22.4**	21.9	19.1
Gross revenue *($/bbl)*[6]	**29.76**	37.73	27.57
Royalties *($/bbl)*	**1.82**	0.90	0.50
Production and operating costs *($/bbl)*[6]	**11.12**	9.84	8.11
Operating netback *($/bbl)*	**16.82**	26.99	18.96
Sunrise Energy Project			
Bitumen			
Sales volumes *(mbbls/day)*	**25.0**	20.1	12.8
Gross revenue *($/bbl)*[6]	**14.50**	29.79	14.46
Royalties *($/bbl)*	**1.36**	0.77	0.40
Production and operating costs *($/bbl)*[6]	**14.43**	16.91	26.56
Operating netback *($/bbl)*	**(1.29)**	12.11	(12.50)
Thermal Development Bitumen Total			
Sales volumes *(mbbls/day)*	**124.2**	119.1	97.4
Gross revenue *($/bbl)*[7]	**30.17**	38.20	27.63
Royalties *($/bbl)*	**2.09**	2.08	1.48
Production and operating costs *($/bbl)*[6]	**11.43**	11.27	10.94
Operating netback *($/bbl)*	**16.65**	24.85	15.21

Operating Netback Analysis (continued)	2018	2017	2016
Non - Thermal Development			
Medium Oil			
Sales volumes *(mbbls/day)*	**1.9**	2.1	2.1
Gross revenue *($/bbl)*(6)	**43.91**	48.30	36.97
Royalties *($/bbl)*	**2.31**	2.41	1.80
Heavy Oil			
Sales volumes *(mbbls/day)*	**36.8**	43.5	44.9
Gross revenue *($/bbl)*(6)	**39.25**	43.41	31.13
Royalties *($/bbl)*	**3.86**	4.42	2.44
Natural Gas			
Sales volumes *(mmcf/day)*	**19.6**	24.6	17.7
Gross revenue *($/mcf)*(6)	**1.66**	2.02	1.76
Royalties ($/mcf)	**0.07**	0.11	0.09
Non - Thermal Development Medium Oil, Heavy Oil & Natural Gas Total(2)			
Sales volumes *(mboe/day)*	**42.0**	49.7	50.0
Gross revenue *($/boe)*(6)	**37.18**	41.04	30.17
Royalties *($/boe)*	**3.53**	4.03	2.34
Production and operating costs *($/boe)*(6)	**26.67**	22.21	18.52
Operating netback *($/boe)*	**6.98**	14.80	9.31
Western Canada			
Crude Oil			
Light & Medium Oil			
Sales volumes *(mbbls/day)*	**7.5**	10.0	21.3
Gross revenue *($/bbl)*(6)	**58.70**	54.13	41.35
Royalties *($/bbl)*	**10.42**	6.97	4.04
Heavy Oil			
Sales volumes *(mbbls/day)*	**—**	0.9	9.2
Gross revenue *($/bbl)*(6)	**—**	42.14	27.39
Royalties *($/bbl)*	**—**	4.86	3.60
Western Canada Crude Oil Total			
Sales volumes *(mbbls/day)*	**7.5**	10.9	30.5
Gross revenue *($/bbl)*(6)	**58.70**	53.15	37.14
Royalties *($/bbl)*	**10.42**	6.80	3.91
Production and operating costs *($/bbl)*(6)	**31.17**	33.69	25.16
Operating netback *($/bbl)*	**17.11**	12.66	8.07
Natural Gas & NGLs			
NGLs			
Sales volumes *(mbbls/day)*	**12.0**	10.5	8.0
Gross revenue *($/bbl)*(6)	**35.71**	32.08	31.14
Royalties *($/bbl)*	**9.58**	10.16	7.59
Natural Gas			
Sales volumes *(mmcf/day)*	**271.4**	353.6	424.7
Gross revenue *($/mcf)*(4)(6)	**1.80**	2.31	2.06
Royalties *($/mcf)*(4)(5)	**(0.13)**	(0.12)	(0.04)
Western Canada Natural Gas and NGL Total(2)			
Sales volumes *(mmcfe/day)*	**343.4**	416.6	472.7
Gross revenue *($/mcfe)*(6)	**2.67**	2.77	2.37
Royalties *($/mcfe)*	**0.23**	0.15	0.08
Production and operating costs *($/mcfe)*(7)	**1.66**	2.02	1.90
Operating netback *($/mcfe)*	**0.78**	0.60	0.39

Operating Netback Analysis (continued)	2018	2017	2016
Atlantic			
Light Oil			
Sales volumes *(mbbls/day)*	**21.4**	34.0	33.1
Gross revenue *($/bbl)*	**95.97**	71.69	60.01
Royalties *($/bbl)*	**7.90**	6.75	8.70
Production and operating costs *($/bbl)*	**27.21**	17.12	18.48
Offshore transportation *($/bbl)*(3)	**3.01**	2.13	2.46
Operating netback *($/bbl)*	**57.85**	45.69	30.37
Asia Pacific – China			
Light Oil			
Sales volumes *(mbbls/day)*	**—**	5.3	6.6
Gross revenue *($/bbl)*	**—**	72.08	54.98
Royalties *($/bbl)*	**—**	5.08	3.68
NGLs			
Sales volumes *(mbbls/day)*	**8.4**	7.0	6.0
Gross revenue *($/bbl)*	**72.77**	59.50	47.14
Royalties *($/bbl)*	**4.21**	3.38	2.65
Natural Gas			
Sales volumes *(mmcf/day)*	**184.8**	152.9	113.5
Gross revenue *($/mcf)*	**13.73**	13.29	13.58
Royalties *($/mcf)*	**0.80**	0.74	0.72
Asia Pacific – China Light Oil, NGLs & Natural Gas Total(2)			
Sales volumes *(mboe/day)*	**39.2**	37.8	31.5
Gross revenue *($/boe)*	**80.31**	74.94	69.40
Royalties *($/boe)*	**4.67**	4.33	3.84
Production and operating costs *($/boe)*	**4.59**	6.16	8.01
Operating netback *($/boe)*	**71.05**	64.45	57.55
Asia Pacific – Indonesia(7)			
NGLs			
Sales volumes *(mbbls/day)*	**2.5**	0.6	—
Gross revenue *($/bbl)*	**95.67**	77.79	—
Royalties *($/bbl)*	**14.96**	12.32	—
Natural Gas			
Sales volumes *(mmcf/day)*	**31.2**	8.0	—
Gross revenue *($/mcf)*	**9.81**	9.51	—
Royalties *($/mcf)*	**1.07**	1.03	—
Asia Pacific – Indonesia NGLs & Natural Gas Total(2)			
Sales volumes *(mboe/day)*	**7.7**	1.9	—
Gross revenue *($/boe)*	**70.60**	63.46	—
Royalties *($/boe)*	**9.15**	8.08	—
Production and operating costs *($/boe)*	**10.04**	12.59	—
Operating netback *($/boe)*	**51.41**	42.79	—

Operating Netback Analysis (continued)	2018	2017	2016
Asia Pacific – Total(7)			
Light Oil			
Sales volumes *(mbbls/day)*	**—**	5.3	6.6
Gross revenue *($/bbl)*	**—**	72.08	54.98
Royalties *($/bbl)*	**—**	5.08	3.68
NGLs			
Sales volumes *(mbbls/day)*	**10.9**	7.6	6.0
Gross revenue *($/bbl)*	**77.94**	60.94	47.14
Royalties *($/bbl)*	**6.64**	4.08	2.65
Natural Gas			
Sales volumes *(mmcf/day)*	**216.0**	160.9	113.5
Gross revenue *($/mcf)*	**13.16**	13.10	13.58
Royalties *($/mcf)*	**0.84**	0.76	0.72
Asia Pacific Light Oil, NGLs & Natural Gas Total(2)			
Sales volumes *(mboe/day)*	**46.9**	39.7	31.5
Gross revenue *($/boe)*	**78.72**	74.38	69.40
Royalties *($/boe)*	**5.40**	4.52	3.84
Production and operating costs *($/boe)*	**5.53**	6.47	8.01
Operating netback *($/boe)*	**67.79**	63.39	57.55

(1) *The operating netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. Operating netback is a non-GAAP measure. Refer to Section 9.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.*
(2) *Includes associated co-products converted to boe and mcf.*
(3) *Includes offshore transportation costs shown separately from price received.*
(4) *Includes sulphur sales revenues/royalties.*
(5) *Alberta Gas Cost Allowance reported exclusively as gas royalties.*
(6) *Transportation expenses for Western Canada, Non - Thermal Development and Thermal Development has been deducted from both gross revenue and production and operating costs to reflect the actual price received at the oil and gas lease.*
(7) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*

Advisories

Forward-Looking Statements and Information

Certain statements in this annual report are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this annual report are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "scheduled" and "outlook"). In particular (and in addition to other statements referred to under "Forward-Looking Statements" in section 9.1 of the Management's Discussion and Analysis for the year ended December 31, 2018 (the "MD&A") contained in this annual report), forward-looking statements in this annual report include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally, general strategic plans and growth strategies;
- with respect to the Company's thermal developments: estimated production and expected timing of first production from the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East and Edam Central projects; and the expected timing of full implementation of the pilot program for steam-oil ratio optimization;
- with respect to the Company's Offshore business in Asia Pacific, the expected timing of tie-in of seven wells at, and first gas production from, Liuhua 29-1;
- with respect to the Company's Offshore business in Atlantic, the expected timing of start-up, and the expected volume of peak production, at the West White Rose Project; and
- with respect to the Company's Downstream operations: the potential sale of the Canadian retail and commercial fuels business and the Prince George Refinery; the expected timing of completion of the crude oil flexibility project at the Lima Refinery and the expected increase in processing capacity as a result thereof; and the expected timing that operations will resume at the Superior Refinery.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserves and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this annual report are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate.

Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third-party consultants, suppliers and regulators, among others.

Advisories

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company's Annual Information Form for the year ended December 31, 2018 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe some of the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

Non-GAAP Measures

In addition to the terms referred to under "Non-GAAP Measures" in section 9.3 of the MD&A contained in this annual report, this annual report contains references to the terms "EBITDA", "value chain operating netback", "sustaining capital" and "gross margin". None of these measures is used to enhance the Company's reported financial performance or position. These measures are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity.

EBITDA is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. EBITDA is presented to assist management and investors in analyzing operating performance by business in the stated period. EBITDA equals net earnings (loss) plus finance expenses (income), provisions for (recovery of) income taxes, and depletion, depreciation and amortization.

Value chain operating netback is a non-GAAP measure used in the oil and gas industry. This measure assists the Company's investors to evaluate the operating performance of the Integrated Corridor. Value chain operating netback is calculated as an average realized price of synthetic crude and other refined products less royalties, operating costs, transportation costs and processing costs on a per unit basis.

Sustaining capital is a non-GAAP measure that represents the additional development capital that is required by the business to maintain production and operations at existing levels. Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. Sustaining capital does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

Gross margin is a non-GAAP measure that is calculated as revenue less purchases of crude oil and product. This measure assists the Company's investors to evaluate the operating performance of the Integrated Corridor.

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have been audited and reviewed by Sproule, an independent qualified reserves auditor, have an effective date of December 31, 2018 and represent the Company's working interest share; (ii) projected and historical production volumes provided are gross, which represents the total or the Company's working interest share, as applicable, before deduction of royalties; (iii) all Husky working interest production volumes quoted are before deduction of royalties; and (iv) historical production volumes provided are for the year ended December 31, 2018.

The Company uses the term "barrels of oil equivalent" (or "boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

The Company uses the term "proved reserves life index", which is consistent with other oil and gas companies' disclosures. The Company's proved reserves life index for a given period is determined by taking the Company's total proved reserves at the end of that period divided by the Company's upstream gross production for the same period. Readers are cautioned that the term proved reserves life index may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not reflect the actual life of the reserves.

The Company uses the term "reserves replacement ratio", which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserve additions for that period divided by the Company's upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserves base during a given period. Reserves replacement ratios presented as excluding economic factors exclude the impact that changing oil and gas prices, inflation and regulations have on reserves amounts.

Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the U.S. Securities and Exchange Commission.

All currency is expressed in Canadian dollars unless otherwise indicated.

Corporate Information

Board of Directors

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman(2)

William Shurniak
Deputy Chairman(1)

Robert J. Peabody
President & Chief Executive Officer

Stephen E. Bradley(1)(3)

Asim Ghosh

Martin J.G. Glynn(2)(3)

Poh Chan Koh

Eva L. Kwok(2)(3)

Stanley T.L. Kwok(4)

Frederick S.H. Ma(1)(4)

George C. Magnus(1)

Neil D. McGee(4)

Colin S. Russel(1)(4)

Wayne E. Shaw(1)(3)

Frank J. Sixt(2)

(1) Audit Committee
(2) Compensation Committee
(3) Corporate Governance Committee
(4) Health, Safety & Environment Committee

The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

Executives

Robert J. Peabody
President & Chief Executive Officer

Jeffrey R. Hart
Chief Financial Officer

Robert W.P. Symonds
Chief Operating Officer

Peter Ostenfeld-Rosenthal
Senior Vice President, Safety & Operations Integrity

Gerald F. Alexander
Senior Vice President, Western Canada

Bradley H. Allison
Senior Vice President, Exploration

Janet E. Annesley
Senior Vice President, Corporate Affairs

P. Andrew Dahlin
Senior Vice President, Heavy Oil & Oil Sands

Nancy F. Foster
Senior Vice President, Human & Corporate Resources

David A. Gardner
Senior Vice President, Business Development

James D. Girgulis
Senior Vice President, General Counsel & Secretary

Robert M. Hinkel
Chief Operating Officer, Asia Pacific Region

Terry J. Manning
Senior Vice President, Engineering, Procurement & Project Management

Trevor Pritchard
Senior Vice President, Atlantic Region

Jeffrey E. Rinker
Senior Vice President, Downstream

Investor Information

Common Share Information

Year ended December 31		2018	2017	2016
Share price *(dollars)*	High	**22.99**	17.83	18.10
	Low	**13.33**	13.39	11.34
	Close at December 31	**14.11**	17.75	16.29
Average daily trading volumes *(thousands)*		**1,321**	1,022	1,430
Number of common shares outstanding *(thousands)*		**1,005,122**	1,005,120	1,005,452
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**1,005,121**	1,005,309	1,004,875
	Diluted	**1,006,147**	1,005,310	1,004,875

Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite Index, S&P/TSX Capped Energy Index and S&P/TSX 60 Index.

Toronto Stock Exchange Listing

HSE, HSE.PR.A, HSE.PR.B, HSE.PR.C, HSE.PR.E and HSE.PR.G (at December 31, 2018)

Outstanding Shares

The number of common shares outstanding at December 31, 2018 was 1,005,121,738.

Transfer Agent and Registrar

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company N.A. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Canton, Massachusetts in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-800-564-6253 (in Canada and the United States) and 1-514-982-7555 (outside Canada and the United States).

Auditors

KPMG LLP
3100, 205 - 5th Avenue S.W.
Calgary, Alberta T2P 4B9

Annual Meeting

The Annual Meeting of Shareholders will be held at 10:30 a.m. on Friday, April 26 in the Performance Hall at Studio Bell, 850 - 4th Street S.E., Calgary, Alberta, Canada.

Additional Publications

The following publications are available on our website:

- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

Corporate Office

Husky Energy Inc.
707 - 8th Avenue S.W.
Box 6525, Station D
Calgary, Alberta T2P 3G7
Telephone: (403) 298-6111
Fax: (403) 298-7464

Website

www.huskyenergy.com

Husky Energy

707 - 8th Avenue S.W.
Box 6525, Station D
Calgary, Alberta T2P 3G7
www.huskyenergy.com

Please recycle. The paper, paper mill, and printer are all Forest Stewardship Council certified, which is an international network that promotes environmentally appropriate and socially beneficial management of the world's forests.

Design and Production: One Design
Printing: CBN Commercial Solutions
This report was printed in Canada.