Husky

Our Energy

Annual Report **2019**

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.

Husky has two business segments:

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

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

2019 Results

Financial[1]

Year ended December 31	2019	2018
(millions of dollars except where indicated)		
Gross revenues and Marketing and other	**20,306**	22,587
Revenues, net of royalties	**19,983**	22,252
Funds from operations[2]	**3,251**	4,004
Per common share – basic *($/share)*	**3.23**	3.98
Cash flow – operating activities	**2,971**	4,134
Capital expenditures[3][4]	**3,432**	3,578
Free cash flow[2]	**(181)**	426
Net earnings	**(1,370)**	1,457
Per common share – basic *($/share)*	**(1.40)**	1.41
Net debt[5]	**3,745**	2,881
Ordinary dividends per common share declared for the year *(dollars)*	**0.500**	0.450

Operations

Upstream production, before royalties		
Crude oil *(mbbls/day)*	**184.9**	191.8
Natural gas liquids *(mbbls/day)*	**22.6**	22.9
Conventional natural gas *(mmcf/day)*	**500.9**	507.0
Total equivalent production *(mboe/day)*[6]	**290.0**	299.2
Total proved reserves, before royalties *(mmboe)*[7]	**1,431**	1,471
U.S. refinery net throughput *(mbbls/day)*[8]	**199.5**	233.9
Canadian refining and upgrading throughput *(mbbls/day)*	**108.5**	113.4

(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) Excludes asset retirement obligations and capitalized interest.
(4) 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.
(5) 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".
(6) Please refer to "Advisories" for full product breakdown.
(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 continued to return value to our shareholders in 2019 while investing for margin growth.

Active portfolio management, including the sale of non-core assets and progressive investments to improve safety, reliability and cost structure, provides a path to free cash flow generation in 2021 as we successfully execute our five-year plan.

Most importantly, the Board and senior management are committed to Husky's goal of world-class process safety performance. We strongly believe that excellence in process safety and operational integrity provides for sustainable, predictable business results and directly benefits our shareholders, employees and the communities where we operate.

Specific actions to improve safety and reliability were implemented in 2019, including embedding the principles of a High Reliability Organization (HRO) and updating our safety management system framework to further strengthen our culture of continuous improvement.

We also recognize the increasing importance of Environmental, Social and Governance (ESG) performance. In 2019, Husky advanced programs and disclosure in areas that are important to our stakeholders, including safety and reliability, climate, Indigenous economic inclusion and talent management. We will continue to report our ESG performance in detail in our annual ESG Report.

Construction on the 10,000 barrel-per-day Spruce Lake Central project in Saskatchewan is being finalized in preparation for first oil mid-year 2020.

Husky made good progress on its financial priorities in 2019 – to maintain the strength of the balance sheet, fund sustaining capital requirements, and to return value to our shareholders through a sustainable cash dividend.

Net debt at the end of 2019 was $3.7 billion or 1.2 times trailing funds from operations. Husky retains the flexibility to increase shareholder returns while continuing to prudently invest in higher margin projects that further lower our break-even oil price.

Husky continues to preserve its capital efficiency through reduced spending, shared project infrastructure and increased operational efficiencies, while also advancing select organic developments in both the Integrated Corridor and Offshore businesses.

Along the Integrated Corridor, first production began at the 10,000 barrel-per-day Dee Valley thermal project. Husky's repeatable, small-scale thermal developments provide low-cost, reliable feedstock for our Upgrader, asphalt plant and U.S. refineries, and are not subject to Alberta government production quotas.

Construction at the Liuhua 29-1 field at the Liwan Gas Project is progressing with first gas production set for the fourth quarter of 2020.

In the Downstream, the safe and orderly completion of the crude oil flexibility project at the Lima Refinery has increased the facility's heavy oil processing capacity to 40,000 barrels per day (bbls/day).

In the high-netback Offshore business, construction was advanced on the Liuhua 29-1 natural gas field in China and at the West White Rose Project in the Atlantic region. Both of these projects are expected to make a strong contribution to free cash flow when they begin production around the end of 2020 and 2022, respectively.

As Husky moves ahead to deliver the five-year plan, including an increased focus on improved process and occupational safety and responsible environmental, social and governance performance, we offer deepest thanks to our shareholders for your continued support as we responsibly deliver our energy to the world.

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

Message from the CEO

In 2019, Husky continued to make good progress on the plans set out at our Investor Day, despite headwinds created by government-mandated curtailments in Alberta and a slower than anticipated return to full volumes in the Atlantic region.

Safety continued to be an enduring value and a critical component of our business as we accelerated our transition to a High Reliability Organization (HRO). The learnings from incidents experienced by Husky and others in the industry over the past years have been a catalyst for positive action within our organization.

Today, our focus on improved process safety and operations integrity has never been stronger, with HRO principles and expectations now integral to our operations. Our target is to be recognized as a world-class process and occupational safety performer when benchmarked against the best in the world. Results in 2019 were encouraging, with a 55% reduction in lost-time injuries, a 15% reduction in recordable injuries, and a more than 50% reduction in Tier 1 Process Safety Events.

With a deep portfolio of low-cost thermal production and enhanced upgrading and refining capacity in the Integrated Corridor business, and fixed-price gas contracts and global pricing in the Offshore business, Husky's value proposition remained on solid footing in 2019 in what proved to be a challenging market environment.

We reduced capital spending in several areas, including less-economic conventional heavy oil and resource play production in Western Canada. Overall, Husky has been able to largely mitigate the volume impact of government-mandated production quotas in Alberta by increasing production in jurisdictions such as Saskatchewan and the Asia Pacific region.

Atlantic region safety training: CEO Rob Peabody, left, with Eric Wakley, VP, Safety & Risk.

Our thermal portfolio in Saskatchewan is focused on capital efficiency and disciplined project execution, with projects paced with egress opportunities and our growing heavy oil processing capacity. Overall Lloydminster region thermal production averaged 92,000 bbls/day in December 2019, and the next two thermal projects at Spruce Lake Central and Spruce Lake North are advancing on schedule towards startup in 2020.

We are further improving our profitability by leveraging existing infrastructure. Our Saskatchewan thermal projects share the same modular design and work teams, and are being delivered into production with assembly-like precision. This consistency in process provides for more sustainable, lower cost production.

In the Downstream manufacturing business, we are capturing increasing value outside the refinery gate as we create new opportunities to accommodate our Upstream heavy oil production and drive to lower our production costs. A reorganization in 2019 has resulted in a leaner operating model and greater ability to capture margins along the Integrated Corridor.

The Sunrise Energy Project is focused on capturing higher margins.

In 2019, the Toledo Refinery had a major planned turnaround and the Lima Refinery was down in the fourth quarter to complete the project to expand its heavy oil processing capacity to 40,000 bbls/day. While impacting this year's results, these turnarounds positioned Husky to improve margin capture in the U.S. refining business in the future.

The Superior Refinery rebuild project commenced in the fall of 2019 and is incorporating additional safety and operational technologies in accordance with our HRO principles. The sale of the Prince George Refinery in the second half of 2019 advanced our objective to more tightly align our heavy oil and Downstream businesses in the Integrated Corridor.

In the Offshore business, the Liwan Gas Project in China and our White Rose developments in the Atlantic region share vessels and subsea infrastructure in their respective areas of operations. At Liwan, which marked its fifth year of high-netback production in 2019, the Liuhua 29-1 field will be tied into the main project infrastructure and started up later this year. The West White Rose Project was more than 55% complete at the end of the year, with startup planned for the end of 2022.

I continue to have full confidence in our drive to create profitable growth for shareholders by delivering capital-efficient projects safely and reliably while continuing to reduce our cost structure and grow funds from operations.

This is our plan. And together, this is our energy.

Rob Peabody

2019 Highlights

Overall

- Annual average production of 290,000 barrels of oil equivalent per day (boe/day)
- Funds from operations of $3.3 billion
- Cash flow from operating activities of $3 billion
- Net loss of $1.3 billion; reflects total non-cash asset impairments and other charges of $2.3 billion (after tax) in the fourth quarter
- Capital spending of $3.4 billion
- $0.500 per common share dividend declared for the year
- Net debt of 1.2 times trailing 2019 funds from operations

The Lloydminster Upgrader is increasing its diesel processing capacity to approximately 10,000 bbls/day.

The Tucker Thermal Project recycles produced water from thermal wells for reuse in steam generation.

Integrated Corridor

- Annual average Upstream net production of 229,800 boe/day
- Upstream average operating netback of $21.92 per barrel
- Startup of the Dee Valley thermal project in Saskatchewan; 10,000 bbls/day nameplate capacity surpassed ahead of schedule
- Upgrading and refining average throughput of 308,000 bbls/day
- Lima Refinery crude oil flexibility project completed; heavy processing capacity increased to 40,000 bbls/day
- Downstream upgrading and refining margin of $17.95 per barrel

Offshore

- Annual average net production of 60,200 boe/day
- Average operating netbacks of $57.87 per boe; $67.10 per boe in Asia Pacific and $33.20 per barrel in the Atlantic
- Completed seven wells and laid initial subsea pipelines for the Liuhua 29-1 field at the Liwan Gas Project
- West White Rose Project more than 55% complete

The Liwan Gas Project marked five years of safe and steady high-netback production in 2019.

Safety and Operations Integrity

Husky's drive to become a world-class process and occupational safety performer was accelerated in 2019 through initiatives to prioritize process safety, operations integrity, maintenance and reliability, with more clearly specified technical and operational requirements throughout the organization and a strengthened culture of continuous improvement.

No major safety incidents were recorded in 2019. Husky achieved more than a 50% reduction in lost-time injuries and Tier 1 process safety events, a best-ever result.

Husky continued to implement the five principles of a High Reliability Organization: promoting knowledge and learning, ensuring standards and procedure compliance, fostering a questioning attitude at all levels of the Company, providing for team backup, and championing integrity.

These principles have been integrated with the existing safety management program. Operational and technical requirements are reflected by processes and procedures that are rigorously documented, have clearer accountabilities and demonstrated competencies that can be systematically checked.

Key performance indicators are regularly benchmarked, with specific processes and actions to further improve operational integrity performance and risk processes. Safety assessments were completed at all major Husky facilities to ensure HRO principles are entrenched and new standardized procedures for incident notification are implemented.

Husky's safety vision is that by the end of 2022, the Company will be global first-quartile in process and occupational safety, as measured against worldwide benchmarks.

Life-Saving Rules awareness training is mandatory for all Husky employees.

2019 Business Highlights

Overview

Average annual production was within guidance at 290,000 boe/day.

In the Integrated Corridor business, overall operating margins were $2.6 billion. The average operating cost of Upstream thermal bitumen production from Lloydminster thermal projects, the Sunrise Energy Project and the Tucker Thermal Project was $12.73 per barrel.

Alberta production continued to be curtailed by government-mandated quotas.

Downstream upgrading and refinery throughput averaged 308,000 bbls/day. The Downstream upgrading and refining margin was $17.95 per barrel.

Offshore, overall operating netbacks were $57.87 per boe – $67.10 per boe in the Asia Pacific region and $33.20 per barrel in the Atlantic region.

Funds from Operations and Free Cash Flow

Funds from operations were $3.3 billion, which takes into account the impact from an extended shutdown at the Lima Refinery, a longer than anticipated ramp up of the *SeaRose* floating production, storage and offloading (FPSO) vessel in the Atlantic region, government-mandated production curtailments in Alberta and the lower commodity price environment.

Cash flow provided by operating activities, including changes in non-cash working capital, was approximately $3 billion in 2019 compared to about $4 billion in 2018.

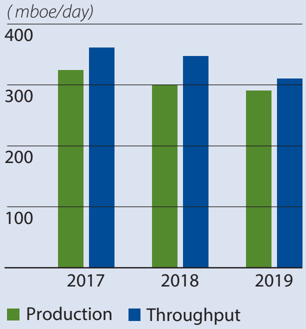
The Dee Valley thermal project in Saskatchewan began production in 2019.

Total non-cash asset impairment and other charges were $2.3 billion (after tax) in the fourth quarter of 2019. These were primarily related to the Company's upstream assets in North America, including the Sunrise Energy Project and the Atlantic and Western Canada segments, and were largely due to lower long-term commodity price assumptions and a reduction in future capital spending.

The reduction in future capital spending has the effect of reducing reserves, which in turn reduces asset values. Other charges included exploration-related write-downs and asset de-recognition at the Lima Refinery associated with redundant equipment following the completion of the crude oil flexibility project.

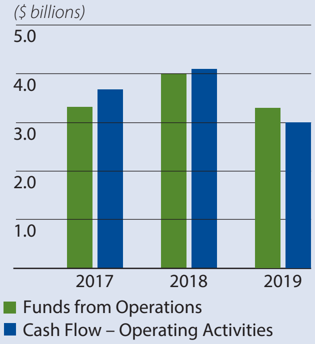
Production and Throughput

(mboe/day)



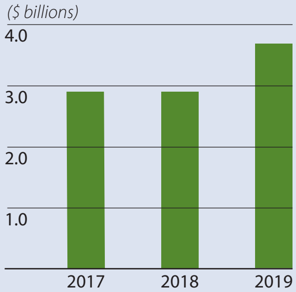
Cash Flow

($ billions)



Net Debt

($ billions)



Debt

Net debt was $3.7 billion at the end of the fourth quarter of 2019, representing 1.2 times trailing funds from operations. Total liquidity (cash and unused credit facilities) at the end of the fourth quarter was $5.7 billion. The Company maintained its investment-grade credit ratings throughout 2019.

Earnings

Net earnings were a loss of $1.4 billion compared to earnings of $1.5 billion in 2018, primarily due to asset impairments and exploration charges booked in the fourth quarter of 2019.

Capital Expenditures

Capital spending was at the low end of guidance at $3.4 billion, including the Superior Refinery rebuild, compared to $3.6 billion in 2018. Superior Refinery rebuild costs are expected to be largely covered by insurance.

This included investment in Saskatchewan thermal projects, the completion of the Lima Refinery crude oil flexibility project, and progressing in-flight construction of the Liuhua 29-1 field offshore China and the West White Rose Project in the Atlantic region.

2019 Reserves Replacement

The proved reserves life index was 13.5 years, comparable to 2018.

Total proved reserves before royalties at the end of 2019 were 1.43 billion boe, compared to 1.47 billion boe at

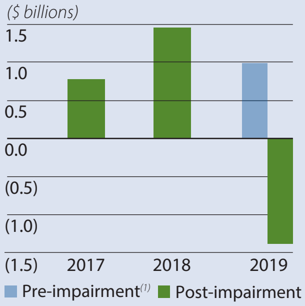
The SeaRose FPSO returned to full rates in mid-2019.

the end of 2018. Proved plus probable reserves were 2.11 billion boe, compared to 2.54 billion boe at the end of 2018, which reflects reduced future capital spending at the Sunrise Energy Project and the Ansell natural gas resource play in Western Canada in the five-year plan.

Proved reserves additions of 174 million boe were primarily related to Lloydminster thermal projects, the Tucker Thermal Project, and the liquids-rich gas resource play at Wembley. These additions were partially offset by a 5 million boe reduction due to economic factors, and 103 million boe of negative technical revisions across the Company mainly associated with lower future capital spending in the five-year plan. Taking the additions and negative revisions into account, the one-year proved reserves replacement ratio was 67%, excluding economic factors (62% including economic factors).

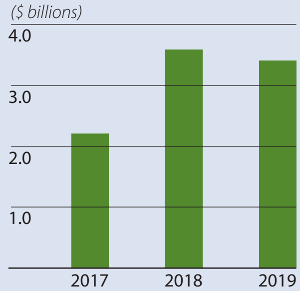
The average three-year annual proved reserves replacement ratio was 166%, excluding economic factors (162% including economic factors), including dispositions in Western Canada of 62 million boe of proved reserves in 2017.

Net Earnings (Loss)

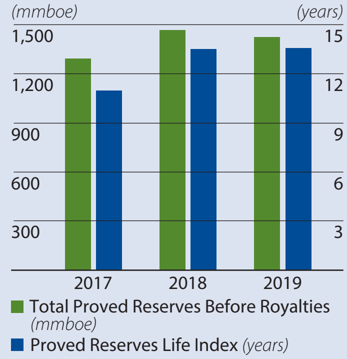


(1) Annual net earnings before non-cash asset impairments and other charges of $2.3 billion after tax, in the fourth quarter of 2019.

Capital Expenditures



Reserves



2019 Operations

Integrated Corridor

Thermal Production

Husky's Upstream thermal bitumen feedstock production is closely matched by its Downstream processing and pipeline takeaway capacity, with tight physical integration providing for increased margin capture.

With low operating costs and advantaged logistics that provide low-cost, reliable feedstock for its Upgrader, asphalt plant and U.S. refineries, Husky's portfolio of Lloydminster thermal projects provide for further reductions in its break-even oil price.

Overall annual production from Lloydminster thermal projects, the Sunrise Energy Project and the Tucker Thermal Project averaged 128,800 bbls/day, compared to 124,200 bbls/day in 2018 (Husky working interest), with total production from Lloydminster thermal projects averaging 92,000 bbls/day in December 2019.

The 10,000 barrel-per-day Dee Valley thermal bitumen project came on production ahead of schedule in the third quarter and quickly ramped up past its nameplate capacity. An additional five Saskatchewan thermal projects are planned, representing 50,000 bbls/day of production.

- At Spruce Lake Central, construction of the Central Processing Facility (CPF) was completed, with first production anticipated by mid-year 2020
- At Spruce Lake North, CPF construction is under way, with first oil planned around the end of 2020
- At Spruce Lake East, procurement and fabrication activities are progressing, with first production around the end of 2021
- At Edam Central, regulatory approval has been received
- Regulatory approval has also been received for Dee Valley 2

The control room at the Lloydminster Upgrader provides for around-the-clock process monitoring.

The Superior Refinery will produce a full slate of products, including diesel, asphalt and gasoline, when it restarts in 2021.

The North Leg of the Saskatchewan Gathering System was placed in service and, together with the completion of the North Leg and Spruce Lake extensions in 2020, will support production from Husky's additional thermal developments. Husky has a 35% working interest in Husky Midstream Limited Partnership, which owns and operates approximately 2,200 kilometres of pipeline in the Lloydminster region.

Downstream

Husky's Downstream business remains well positioned with upgrading and asphalt refining options in Canada, large refining and storage capacity in both Canada and the U.S., and secured pipeline access to the U.S., including 75,000 bbls/day of capacity on the existing Keystone pipeline.

The Company improved its heavy oil processing capacity in 2019 to accommodate its growing Upstream thermal feedstock production. In the U.S., a project to increase heavy oil processing capacity at the Lima Refinery from 10,000 bbls/day to 40,000 bbls/day was completed.

Overall peak throughput capacity at the Lima Refinery increased to 175,000 bbls/day as a result of efficiency improvements and an ongoing focus on reliability.

The rebuild of the Superior Refinery began in the fourth quarter of 2019. Following its scheduled completion in 2021, the refinery will run in a continuous mode averaging 45,000 bbls/day of throughput, compared to a previous run rate of 40,000 bbls/day. Heavy oil processing capacity will be improved from 20,000 bbls/day to 25,000 bbls/day, and the refinery will produce a full slate of products, including diesel, asphalt and gasoline.

In Canada, a project is under way at the Lloydminster Upgrader to increase diesel production from 6,000 bbls/day to nearly 10,000 bbls/day in 2020.

Husky sold the 12,000 barrel-per-day Prince George Refinery as it increases its focus on core assets within the Integrated Corridor and Offshore.

2019 Operations

With the completion of the Lima Refinery crude oil flexibility project at the end of 2019, overall Downstream capacity was 355,000 bbls/day, including 195,000 bbls/day of heavy oil upgrading and conversion capacity. Refining capacity is expected to reach 400,000 bbls/day by the end of 2021 as the Superior Refinery resumes operations, creating overall heavy oil processing capacity of 220,000 bbls/day.

Resource Plays

The Company continues to pace investment in liquids-rich resource plays in Western Canada with an ongoing drive to lower costs, optimize production rates and reduce cycle times.

In the oil and liquids-rich Montney formation, five wells were drilled in the Wembley and Karr areas, with six Wembley wells producing at the end of 2019.

Offshore

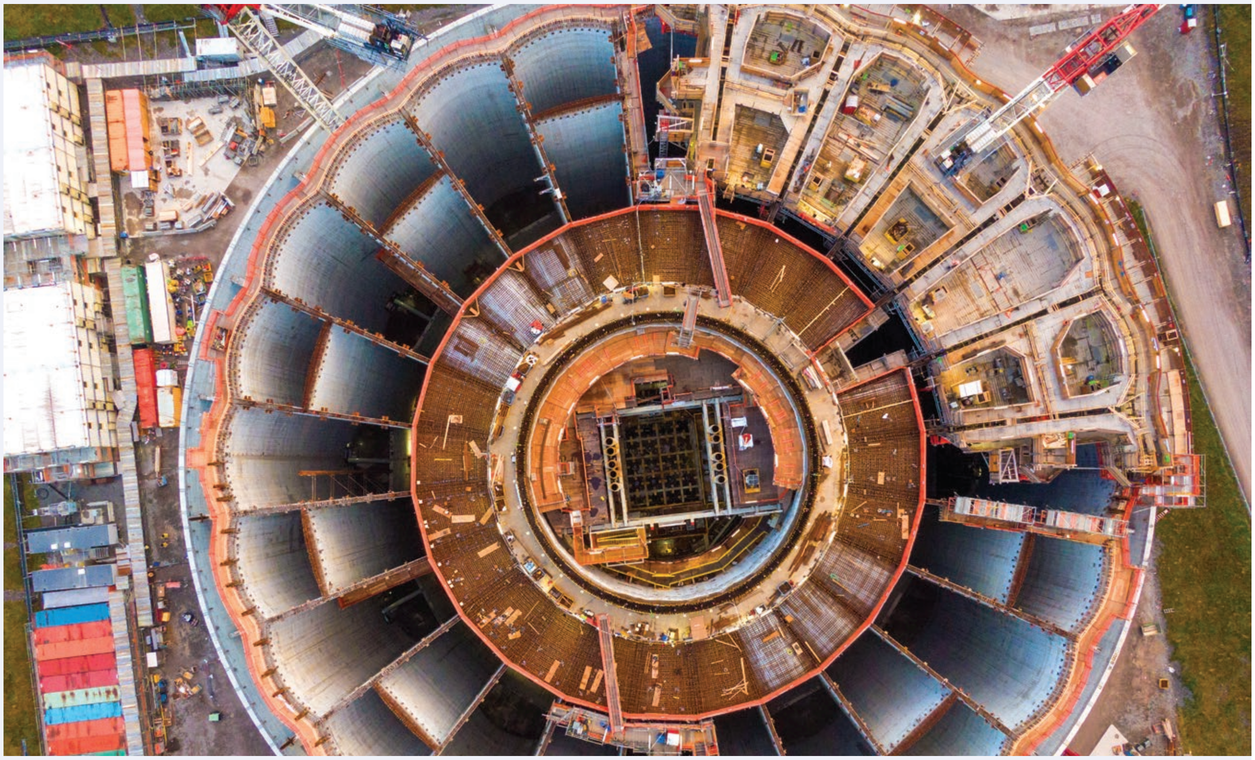
Asia Pacific

Total gross natural gas and liquids production from the Liwan Gas Project averaged 73,200 boe/day (35,900 boe/day Husky working interest). Total production consisted of conventional natural gas production of 349 million cubic feet per day (mmcf/day) and NGL production of 15,100 bbls/day. Realized gas pricing at Liwan was $14.02 per thousand cubic feet (mcf), with liquids pricing of $67.28 per barrel.

Construction of the third deepwater Liwan field at Liuhua 29-1 was advanced, with the completion of all seven wells and initial pipeline installation. The field will be tied into existing Liwan subsea infrastructure later this year, with first gas expected in the fourth quarter.

Target production is 45 mmcf/day of gas and 1,800 bbls/day of liquids when fully ramped up, reflecting Husky's 75% working interest.

Once fully ramped up, the Liuhua 29-1 field will add about 9,000 boe/day to Husky's Asia Pacific production portfolio.



The final quadrant of the West White Rose concrete gravity base was completed in the fourth quarter.

Offshore Indonesia, total sales gas and liquids volumes from the BD Project averaged 19,700 boe/day (7,900 boe/day Husky working interest). Production consisted of natural gas production of 82 mmcf/day and NGL production of 6,100 bbls/day. The gas was sold into the East Java market for a realized price of $9.87 Cdn per mcf with liquids pricing of $88.91 Cdn per barrel.

In the Madura Strait offshore Indonesia, two shallow water platforms were installed at the combined MDA-MBH fields, with seven development wells scheduled to be drilled in 2020. Gas production and sales are planned to commence in 2021. Subsequently, a third platform is planned to be installed at the MDK field and tied into the MDA-MBH infrastructure. This development will include a floating production unit to process the gas.

Processed gas from the three fields will be tied directly into the existing subsea pipeline system and sold into the East Java market under long-term contracts.

Atlantic

Overall average oil production in the Atlantic region was approximately 16,400 bbls/day, Husky working interest, reflecting the safe return to operations of five drill centres at the White Rose field following a 2018 oil release from a subsea flowline connector near the South White Rose Extension.

Two new infill production wells were brought online in the second quarter and ramped up to a combined peak capacity of 8,000 bbls/day, Husky working interest.

At the West White Rose Project, construction on the concrete gravity structure and related topsides was more than 55% complete by year end. First oil is planned for around the end of 2022, with anticipated 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.

Environmental, Social and Governance

Measuring and reporting on a broad spectrum of ESG performance – including climate-related risks, Indigenous engagement and corporate citizenship – improves business discipline and provides for improved engagement with investors and stakeholders. The 2019 ESG Report provided performance data on priority topics such as water use and availability, safety and operations integrity, and innovation and advanced technology.

Energy industry investors and stakeholders are increasingly advocating for improved management and disclosure of climate-related business risks. Husky acknowledges the risks and opportunities inherent in a low-carbon transition.

In 2019, Husky formed a strike force to examine climate-related risks and opportunities, and how it can best manage and report those risks to shareholders. Significant progress was made on Husky's climate compliance program, which is a project to ensure the Company's carbon-related operational data is robust, auditable, and meets regulatory requirements.

Participating in local Pride parades and LGBTQ+ events helps foster a more diverse, inclusive work environment.

Husky's Remediation & Reclamation team volunteered to remove a noxious weed from Calgary's Weaselhead natural environment park.

The Company continues work to reduce its carbon emissions through various initiatives, including CO_2 capture and injection, improving steam-oil ratios and reducing diluent use. Overall methane emissions were reduced by 45% between 2014 and 2018, and in Asia, Husky's natural gas is helping to provide a cleaner source of energy than coal for the industrial complex in southern China.

The Company accepted fines under federal legislation related to a 2016 oil spill in Saskatchewan, for which it takes full responsibility. The lessons learned have been incorporated to improve pipeline operations, including the development of an updated leak response protocol, regular geotechnical reviews of pipelines and fibre-optic sensing technology installed on all new large diameter and higher consequence projects.

Corporate Citizenship

Husky's longstanding commitment to the well-being of communities and employees was renewed in 2019 through a new enterprise-wide approach to corporate citizenship that creates a sustainable and meaningful impact by directing funds and expertise towards issues aligned with the Company's business priorities.

The new areas of focus improve access to energy-related education and skills training for Indigenous Peoples, women and youth, support environmental and sustainability initiatives, build safe and resilient communities and support community-based programs that meet critical needs or build economic prosperity.

Husky supported various initiatives in 2019 through corporate investments and in-kind contributions totalling approximately $4 million. Employees volunteered more than 13,000 hours in their local communities. The Company also conducted community perception surveys to inform and enhance community engagement plans in regions where it operates.

Indigenous Engagement & Economic Inclusion

Guided by Canada's Truth and Reconciliation Commission report, Husky advanced its approach to Indigenous engagement and economic inclusion in 2019 by developing a foundation for a more meaningful approach to working with, and supporting, Indigenous communities and their right to self-determination.

This included external outreach programs to encourage advanced education through scholarships and mentoring while providing support to enhance community wellness and culture. A new Indigenous Economic Inclusion program was introduced that has contributed to a 65% increase in Indigenous procurement in Husky's supply chain since 2016. The Company has provided a total of approximately $500 million in business to companies with partial or whole Indigenous ownership since 2008.

First Nation communities laced up for fun at a Husky hockey camp in Saskatchewan.


A Husky-sponsored entrepreneurship program is opening economic opportunities for Chinese women in need.

Funding and other support was provided to community partners and post-secondary institutions to deliver education and job skills training to Indigenous Peoples in communities where Husky has operations.

Governance

The Company continues to enjoy strong corporate governance, with an independent Board of Directors providing leadership and insightful direction to executive management. The Board oversees strategic planning, risk management, the integrity of internal controls and management information systems, good governance, and standards of business conduct.

In 2019, the Board approved updates to its Code of Business Conduct to provide additional guidance on issues including lobbying, privacy, and the handling of personal information.

For the third year in a row, Husky was named one of Canada's best places to work by Indeed Canada.

Innovation and Technology

Husky's Innovation Gateway program incorporates leading-edge advances and brings together multiple innovation groups and projects to help the Company hone its agility in an increasingly competitive industry.

Husky is committed to proactively identifying, evaluating and adopting new and emerging technologies to further improve safety, environmental and operational processes and efficiency and to reduce costs.

In the Integrated Corridor, initiatives include applying machine learning and Artificial Intelligence in several business areas.

Carbon dioxide from a pilot CO_2 capture facility at the Pikes Peak South thermal project is designed to be injected into a depleted reservoir to increase oil rate and recovery.

A program to improve steam-oil ratios and maximize production was piloted in 2019 at the Sandall thermal project in Saskatchewan. Historical data, including pressure, temperature, flow rates and maintenance data, is being used to develop a predictive model and standardized response for events that may affect steam utilization. Full implementation of the project is planned across all the Company's Saskatchewan thermal operations in 2020.

Husky is also reducing steam-oil ratios through the use of non-condensable gases at two pilot projects at the Sunrise Energy Project and Pikes Peak South.

Data from machine learning is being applied to assess suspended or abandoned wells in Western Canada to determine whether to reactivate or fully abandon the assets. At Rainbow Lake in Alberta, a program is under way to autonomously optimize wells to improve production and asset efficiency.

Fibre-optic cable and drone and satellite technologies are assisting with the early detection of potential pipeline leaks, improving reliability and reducing costs.

In the Downstream, advanced analytics are being employed for preventative maintenance at the Lima Refinery. Pattern recognition software monitors process and mechanical sensor data to help identify any anomalies, further improving operational integrity, reliability and process safety.

Offshore, Husky is experimenting with data science models to provide intelligent recommendations to reduce time, cost and risk for Atlantic well designs.

Pilot programs are also using robotic process automation for repetitive supply chain and finance tasks, providing for improved productivity and focus on higher value opportunities.

Husky will continue to build out its technology ecosystem and networks, including working with multiple partners – from large solution providers to small startups, consortiums, and internal competency networks. This includes an investment in B.C.-based Svante Inc. to develop and implement an innovative adsorbent (nano-materials) solution to capture CO_2 from flue gas at less than half the cost of current technology. The 30 tonne-per-day project, which is now operational at the Pikes Peak South thermal project, captures CO_2 from a once-through steam generator for use in heavy oil recovery.

Management's Discussion and Analysis

February 26, 2020

Contents

1.0 Financial Summary

Selected Annual Information *($ millions, except where indicated)*	2019	2018	2017
Gross revenues and Marketing and other	**20,306**	22,587	18,946
Net earnings (loss) by business segment			
Upstream	**(1,590)**	790	260
Downstream	**332**	1,000	448
Corporate	**(112)**	(333)	78
Net earnings	**(1,370)**	1,457	786
Net earnings (loss) per share – basic	**(1.40)**	1.41	0.75
Net earnings (loss) per share – diluted	**(1.41)**	1.40	0.75
Cash flow – operating activities	**2,971**	4,134	3,704
Funds from operations[1]	**3,251**	4,004	3,306
Ordinary dividends per common share declared for the year	**0.500**	0.450	0.075
Dividends per cumulative redeemable preferred share, series 1	**0.60**	0.60	0.60
Dividends per cumulative redeemable preferred share, series 2	**0.85**	0.74	0.57
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	**33,122**	35,225	32,927
Total debt[2]	**5,520**	5,747	5,440
Net debt[2]	**3,745**	2,881	2,927

(1) *Funds from operations is a non-GAAP measure. 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 an international 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 generate returns from investing in a deep portfolio of projects and other opportunities across 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" and collectively with Atlantic, "Offshore"). These investments are intended to provide for increasing margins, funds from operations and earnings. A strong balance sheet, deep physical integration and largely fixed price contracts in Asia Pacific provide resilience to market volatility, while preserving upside exposure to rising commodity prices.

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% working interest and operatorship) and the Lima Refinery, the BP-Husky Toledo Refinery (50% working interest) and the Superior Refinery 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 Asia Pacific and Atlantic.

2.2 Operations Overview and 2019 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 conventional 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.

Exploration and Production

Thermal Developments

The Company continued to advance its inventory of thermal projects in 2019, with the commencement of production in August 2019 at its Dee Valley Thermal Project in Saskatchewan. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total thermal bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 128,800 bbls/day in 2019 (Husky working interest). Production was impacted by government-mandated production quotas in Alberta and planned turnarounds at the Sunrise Energy Project and nine of the Saskatchewan thermal plants.

Lloyd Thermal Projects

The following table shows major projects and their status as at December 31, 2019:

Project Name	Nameplate Capacity (bbls/day)	Expected Project Production Date	Project Status
Dee Valley	10,000	On production August 2019	First steam was achieved on June 30, 2019, with first oil on August 24, 2019. Reached nameplate capacity on September 30, 2019.
Spruce Lake Central[1]	10,000	Mid-Year 2020	Central Processing Facility ("CPF") construction is complete and module setting on well pads has begun. Overall project is 90% complete.
Spruce Lake North	10,000	Around the end of 2020	CPF fabrication and module setting is complete. Overall project is 50% complete.
Spruce Lake East	10,000	Around the end of 2021	Regulatory approvals have been received, and lease construction is complete. Procurement and fabrication programs are in progress.
Edam Central	10,000	2022	Regulatory approvals have been received.
Dee Valley 2	10,000	2023	Project sanctioned in November 2019, and regulatory approvals have been received.

(1) *Previously expected to start production by the second half of 2020.*

Tucker Thermal Project

Total annual production in 2019 averaged 23,700 bbls/day and was impacted by the government-mandated production quotas in Alberta.

Sunrise Energy Project

Total annual production in 2019 averaged 49,200 bbls/day (24,600 bbls/day Husky working interest) and was impacted by the government-mandated production quotas in Alberta and a planned turnaround at one of the two CPFs in the second quarter of 2019.

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 Cold and Enhanced Oil Recovery ("EOR") consists of a combination of production technologies including CHOPS, horizontal wells and EOR projects.

In 2018, the Company sanctioned a full-field polymer injection project at Aberfeldy, and injection began in 2019.

During 2019, the Company operated three carbon dioxide ("CO_2") injection 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 Pikes Peak South facility in Saskatchewan.

Total annual production in 2019 averaged 34,400 bbls/day and was also impacted by the government-mandated production quotas in Alberta.

Western Canada

The Company continues to execute its resource play strategy in Western Canada to advance developments in the Montney Formation.

Oil and Natural Gas Resource Plays

The Company drilled five wells at Wembley and Karr, which completed the 2019 Montney drilling program. The Company had six Wembley wells producing at the end of 2019 with five Karr wells producing in January 2020.

Asia Pacific

The Company's Asia Pacific business produces conventional natural gas and NGL in the South China Sea and the Madura Strait offshore Indonesia. Conventional natural gas is sold into the South China and East Java markets under long-term contracts. NGL in both regions is sold at market prices.

The Company's interests include participating interests in 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 assets consist of the producing BD field, the MDA, MBH, MDK and MAC developments and three additional discoveries. The Company has participating interests in additional exploration blocks offshore Taiwan and Indonesia, and has signed a Strategic Cooperation Agreement with China National Offshore Oil Corporation Limited ("CNOOC") covering two offshore areas in the South China Sea for additional exploration opportunities.

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 73,200 boe/day (35,900 boe/day Husky working interest) in 2019. Total production consisted of conventional natural gas production of 349 mmcf/day and NGL production of 15,100 bbls/day.

Substantial construction work was completed in 2019 at the Liuhua 29-1 development project, the third deepwater gas field to be developed as part of the Liwan Gas Project. During 2019, the remaining three wells were drilled, and all seven wells in the full field development were fully completed. The production pipeline and the mono-ethylene glycol supply line were engineered, fabricated and installed. The project is now approximately 80% complete, and construction activities will resume in March 2020. During 2020, the control system and connecting flow lines will be installed and the Field will be placed in production. First gas production from the Liuhua 29-1 field is expected by the end of 2020. Husky holds a 75% working interest in this field. CNOOC holds the remaining 25% working interest.

Block 15/33

The Company is progressing commercial development plans following the successful drilling and testing of the XJ34-3-2 exploration well. The block boundaries have been expanded and additional exploration and appraisal drilling is planned in 2020.

The Company is the operator of the block with a working interest of 100% during the exploration phase. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51% in the block.

Block 16/25

The Company drilled one exploration well in the third quarter of 2018, which encountered non-commercial hydrocarbons. This block was released and the costs written off in 2019 after technical evaluations were completed.

Blocks 22/11 and 23/07

The Company and CNOOC signed two Production Sharing Contracts ("PSC") for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea in the first half of 2018. Initial evaluation work of existing data on these two blocks is currently being carried out to assess exploration potential. The Company has elected to move into the second exploration phase for Block 23/07.

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

Indonesia

Madura Strait

Total production averaged 19,700 boe/day (7,900 boe/day Husky working interest) in 2019. Production consisted of conventional natural gas production of 82 mmcf/day and NGL production of 6,100 bbls/day.

At the MDA and MBH fields, the two shallow water platforms have been fully installed. Five MDA and two MBH field production wells are expected to be drilled in the 2020 timeframe pending regulatory approval. Contracting for a floating production unit to process the gas is also planned to be finalized during 2020 with fabrication to take place in 2020/2021. Gas production and sales are planned to commence in 2021 with gas sales under government approved contracts into the East Java gas market. Subsequently, an additional shallow water field, MDK, is scheduled to be developed via a separate platform and tied into the MDA and MBH infrastructure.

Anugerah

The Company previously acquired 2-D and 3-D seismic survey data on the contract area. An analysis of that data and data from offset blocks indicated that exploratory drilling would not be economic. The block will be relinquished in February 2020.

Atlantic

The Company's Atlantic business provides production growth opportunities offshore Newfoundland and Labrador.

White Rose Field and Satellite Extensions

A staged and orderly ramp-up of production commenced in January 2019 following a November 2018 spill from a flowline connector at the South White Rose Extension ("SWRX"). The flowline connector was replaced in the second quarter of 2019. Full production was restored to the White Rose field and satellite extensions in mid-August, following regulatory approvals to resume operations from the SWRX and North Amethyst Drill Centres.

Construction of the West White Rose Project continued on multiple fronts including the platform's concrete gravity structure. A fourth slipform was completed on the platform's outer caisson, and the first three interior decks were installed. The project is now approximately 57% complete. First production is expected around the end of 2022.

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. The Company has a 68.875% ownership interest, with partners Suncor Energy and Nalcor Energy Oil and Gas holding 26.125% and 5%, 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, providing feedstock for the Upgrader and Asphalt Refinery, and to Hardisty where it connects to downstream pipelines accessing markets across Canada and the United States. 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 completed construction of the Ansell Corser Gas Plant.

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 in service, adding 120 mmcf/day of processing capacity.

Hardisty Tanks

Construction is underway for 1.5 mmbbls of storage at the Hardisty Terminal and is scheduled for completion by the end of 2020.

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 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 Upgrader and its Ohio and Wisconsin refineries.

Downstream Operations

Downstream operations in the Integrated Corridor in Canada include upgrading heavy crude oil feedstock into synthetic crude oil and diesel ("Upgrading"), refining of crude oil, producing ethanol and marketing heavy and synthetic crude oil, refined petroleum products including gasoline, diesel, ethanol-blended fuels, asphalt and ancillary products ("Canadian Refined Products"). It also includes crude oil refining 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 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 margins on refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

Upgrading

The Upgrader has a throughput capacity of 80,000 bbls/day. The 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 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 30,000 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 a combined capacity of 260 million litres per year.

Prince George Refinery

On November 1, 2019, the Company completed the sale of its Prince George Refinery to Tidewater Midstream and Infrastructure Ltd. for $215 million in cash plus an inventory closing adjustment of approximately $53.5 million.

Retail and Commercial Network

The Company is a major regional motor fuel marketer with an average of 553 retail marketing locations in 2019, 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 Canadian Retail and Commercial Fuels Network. The strategic review continues to progress.

U.S. Refining and Marketing

Lima Refinery

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

The crude oil flexibility project at the Lima Refinery is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada, providing the ability to swing between light and heavy crude oil feedstock. The Refinery completed a planned turnaround in the fourth quarter of 2019 and made final tie-ins for the project. The project was completed in early 2020 and the refinery will ramp up to full rates during the first quarter of 2020.

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% by the Company and 50% 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-TAN crude oil to support production from the Sunrise Energy Project. The refinery's nameplate capacity remained unchanged.

During the second and third quarters of 2019, the refinery underwent a planned turnaround.

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.

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround and was taken out of operation. During 2019, demolition, site preparation work and permitting were completed, and the rebuild work commenced. The investment in the rebuild is estimated to be approximately US$750 million, of which the Company anticipates a substantial portion will be recovered from property damage insurance. This represents a change from the previous estimate of greater than US$400 million, with the change being due to a more complete assessment of the extent of equipment damage from the April 26, 2018 incident. The Company anticipates that lost income through April 2020 will be compensated by business interruption insurance. The refinery is being rebuilt with the same configuration, and with the capability to run continuously at the 45,000 bbl/day operating capacity and will be able to produce a full slate of products, including asphalt, gasoline and diesel. Full operations are expected to resume in 2021.

2.3 Business Segments – January 1, 2020

Effective January 1, 2020, the Company's businesses were reorganized under two new business segments: (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" and collectively with Atlantic, "Offshore"). The Company will no longer operate under Upstream and Downstream business segments.

Integrated Corridor

The Company's business in the Integrated Corridor includes: crude oil, bitumen, conventional natural gas, NGL and ethanol production from Western Canada; marketing and transportation of the Company's and other producers' production; the Upgrader and Asphalt Refinery; Husky Midstream Limited Partnership (35% working interest and operatorship); the Lima Refinery, the BP-Husky Toledo Refinery (50% working interest) and the Superior Refinery in the U.S. Midwest; and the marketing of refined petroleum products including gasoline, diesel and ethanol blended fuels through petroleum outlets. Conventional 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 Asia Pacific and Atlantic.

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. Management of debt levels is a priority for Husky given long-term growth plans and future expected volatility in commodity prices. The Company's long-term objective is to maintain a debt to funds from operations ratio of less than 2.0 times. Debt to funds from operations is a non-GAAP measure (refer to Sections 6.4 and 9.3). The Company is also committed to retaining its investment grade credit ratings to support access to debt capital markets and 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 and the continued transition to higher margin production. Refer to Section 6.0 for additional information on the Company's liquidity and capital resources.

3.0 The 2019 Business Environment

The Company's operations were significantly influenced by domestic and international factors in 2019, including, but not limited to, the following:

- Global crude oil inventory levels remained high as the U.S. became a net oil exporter and the world's largest oil producer.
- North American natural gas benchmarks continued to be weak due to infrastructure constraints combined with lower demand for Canadian natural gas in the U.S. as a result of increased U.S. shale production.
- The Government of Alberta set province-wide mandatory production quotas to restrict oil supplies entering the market.
- A continued emphasis on health and safety, the environment, the impacts of climate change, 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 this 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.
- Alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore regions.

The Company considers major business factors in formulating its short and long-term business strategies.

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, 2019.

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		2019	2018
West Texas Intermediate ("WTI") crude oil[(1)]	*(US$/bbl)*	**57.03**	64.77
Brent crude oil[(2)]	*(US$/bbl)*	**64.30**	70.97
Light sweet at Edmonton	*($/bbl)*	**69.22**	69.31
WCS at Hardisty[(3)]	*(US$/bbl)*	**44.28**	38.46
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**54.21**	39.33
WTI/Lloyd crude blend differential	*(US$/bbl)*	**12.40**	26.09
Condensate at Edmonton	*(US$/bbl)*	**52.86**	60.95
NYMEX natural gas[(4)]	*(US$/mmbtu)*	**2.63**	3.09
Nova Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.54**	1.45
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**70.29**	78.07
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**78.00**	87.08
Chicago 3:2:1 crack spread	*(US$/bbl)*	**15.80**	15.94
U.S./Canadian dollar exchange rate	*(US$)*	**0.754**	0.772
Canadian $ Equivalents[(5)]			
WTI crude oil	*($/bbl)*	**75.64**	83.90
Brent crude oil	*($/bbl)*	**85.27**	91.93
WCS at Hardisty	*($/bbl)*	**58.72**	49.82
WTI/Lloyd crude blend differential	*($/bbl)*	**16.45**	33.80
NYMEX natural gas	*($/mmbtu)*	**3.49**	4.00

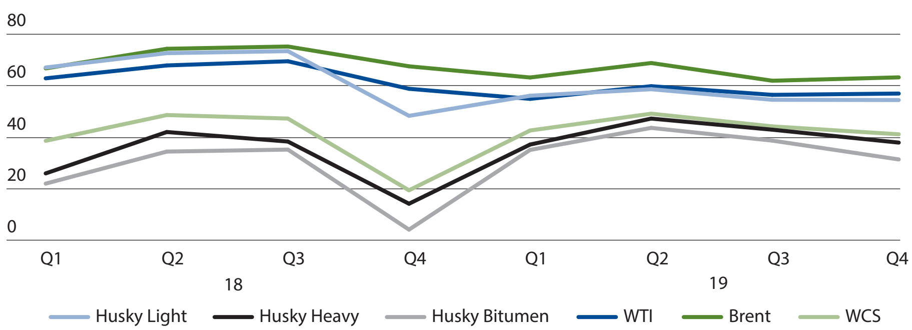
(1) *Calendar month average of settled prices for WTI at Cushing, Oklahoma.*
(2) *Calendar month average of settled prices for Dated Brent.*
(3) *WCS is a heavy blended crude oil, comprised of conventional and bitumen crude oils blended with diluent which terminals at Hardisty, Alberta. Quoted prices 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 prices. 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 long-term contracts.

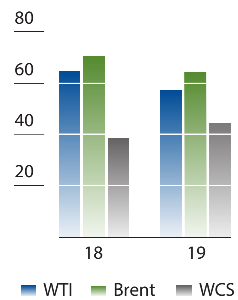
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil and bitumen. In the Upgrading business, heavy crude oil feedstock is processed into light synthetic 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 46% heavy crude oil and bitumen feedstock at the BP-Husky Toledo Refinery. The Company's Canadian Retail and Commercial Fuels Network relies primarily on supply contracts to purchase refined products for resale in the retail distribution network, as well as 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)



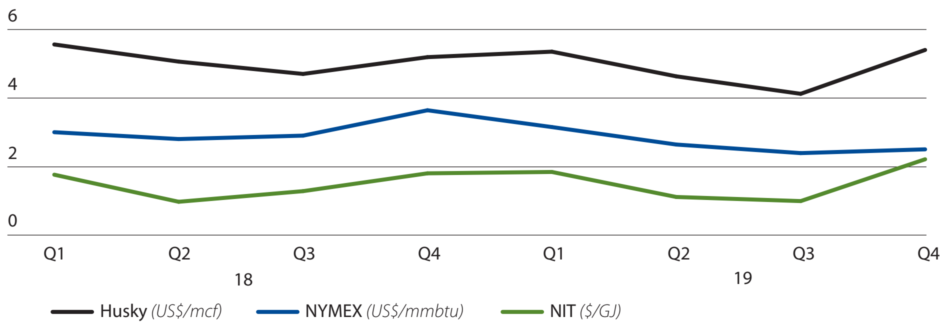
Global crude oil benchmarks remained weakened in 2019 primarily due to a continued oversupply as the U.S became a net oil exporter and the world's largest oil producer. Conversely, the WCS benchmark strengthened in 2019 as the Government of Alberta set province-wide mandatory production quotas to restrict oil supplies entering the market, and consequently the differential between the WCS benchmark and other North American benchmarks tightened in 2019 compared to 2018. WTI averaged US$57.03/bbl in 2019 compared to US$64.77/bbl in 2018. Brent averaged US$64.30/bbl in 2019 compared to US$70.97/bbl in 2018. WCS averaged US $44.28/bbl in 2019 compared to US$38.46/bbl in 2018.

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 for location and quality. 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 significant 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 77% heavy crude oil and bitumen in 2019 compared to 75% in 2018.

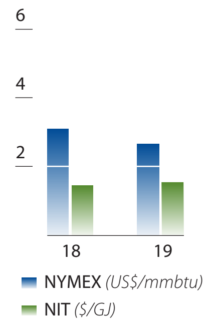
The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton decreased in 2019 compared to 2018, primarily due to the decrease in crude oil benchmark pricing.

Natural Gas Benchmarks

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



Average NYMEX and NIT

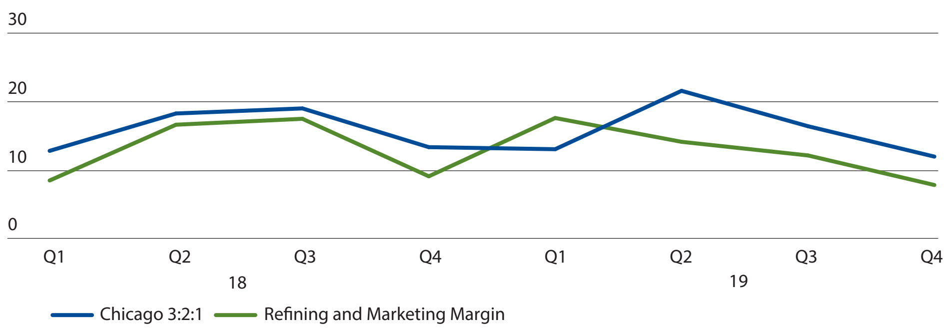


The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is determined by long-term contracts.

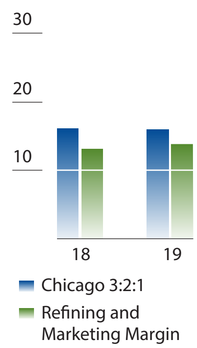
North American natural gas is consumed internally by the Company's Upstream and Downstream operations, helping to mitigate the impact of weak natural gas benchmark prices on results.

Refining Benchmarks

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



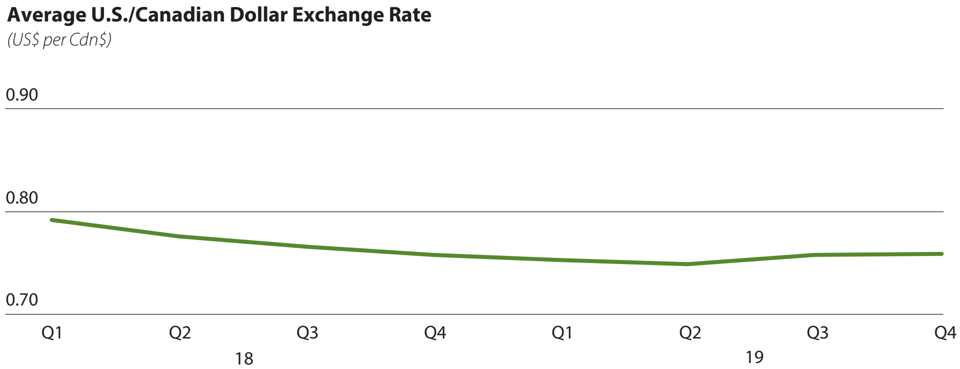
Average Crack Spread
(US$/bbl)

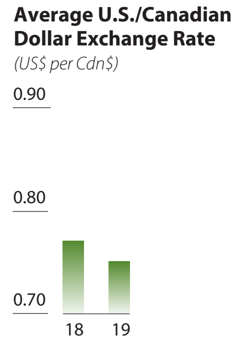


The Chicago 3:2:1 crack spread is a key indicator for U.S. Midwest refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel 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 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 and BP-Husky Toledo refineries contain between 11% and 13% 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





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$0.754 in 2019 compared to US$0.772 in 2018.

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 the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. The Canadian dollar averaged RMB 5.208 in 2019 compared to RMB 5.104 in 2018.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2019 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2019 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2019. 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	2019 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)	**57.03**	*US$1.00/bbl*	**93**	**0.09**	**68**	**0.07**
NYMEX benchmark natural gas price(5)	**2.63**	*US$0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/Lloyd crude blend differential(6)	**12.40**	*US$1.00/bbl*	**(8)**	**(0.01)**	**(6)**	**(0.01)**
Canadian asphalt margins	**25.12**	*Cdn $1.00/bbl*	**10**	**0.01**	**7**	**0.01**
Canadian light oil margins	**0.035**	*Cdn $0.005/litre*	**14**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**15.80**	*US$1.00/bbl*	**98**	**0.10**	**76**	**0.08**
Exchange rate (US $ per Cdn $)(3)(7)	**0.754**	*US$0.01*	**(73)**	**(0.07)**	**(54)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as of December 31, 2019.*
(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.*

The Company's five-year plan was updated at its Investor Day in May 2019, which included guidance for 2019 of cash flow - operating activities and funds from operations in the range of $4.1 - $4.3 billion, a free cash flow projection of $800 million (compared to ($181) actual free cash flow, which is a non-GAAP measure, see Section 9.3 for a reconciliation to the corresponding GAAP measure, Upstream production in the range of 290,000 - 305,000 boe/day and Downstream throughput of 355,000 bbls/day. These projections were based on several pricing assumptions, including WTI benchmark crude at $60 US per barrel, Brent crude oil at $65 US per barrel and a Chicago 3:2:1 crack spread of $16.50 US per barrel.

Actual 2019 results differed materially due to a combination of a weaker oil price environment and several unplanned events, including a longer than anticipated ramp-up of production at the SWRX, the impact of government-mandated production quotas in Alberta and an extended turnaround at the Lima Refinery to complete the tie-in of the crude oil flexibility project.

4.0 Results of Operations

4.1 Segment Earnings

Segmented Earnings	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2019**	2018	**2019**	2018	**2019**	2018
Upstream						
Exploration and Production	**(2,348)**	288	**(1,706)**	223	**2,346**	2,656
Infrastructure and Marketing	**159**	780	**116**	567	**2**	—
Downstream						
Upgrading	**132**	496	**97**	361	**59**	62
Canadian Refined Products	**(7)**	216	**(5)**	158	**119**	74
U.S. Refining and Marketing	**309**	619	**240**	481	**768**	665
Corporate	**(414)**	(471)	**(112)**	(333)	**138**	121
Total	**(2,169)**	1,928	**(1,370)**	1,457	**3,432**	3,578

[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)*	**2019**	2018
Gross revenues	**4,958**	4,330
Royalties	**(323)**	(335)
Net revenues	**4,635**	3,995
Production, operating and transportation expenses	**1,634**	1,527
Selling, general and administrative expenses	**297**	296
Depletion, depreciation, amortization and impairment ("DD&A")	**4,312**	1,811
Exploration and evaluation expenses	**547**	149
Gain on sale of assets	**(3)**	(2)
Other – net	**86**	(120)
Share of equity investment gain	**(50)**	(51)
Financial items	**160**	97
Provisions for (recovery of) income taxes	**(642)**	65
Net earnings (loss)	**(1,706)**	223

Exploration and Production net revenues increased by $640 million in 2019 compared to 2018, primarily due to higher average realized sales prices, partially offset by lower production, both of which are described in more detail below.

Production, operating and transportation expenses increased $107 million in 2019 compared to 2018, which is described in more detail under "Operating Costs".

Exploration and evaluation expenses increased by $398 million in 2019 compared to 2018, primarily due to higher expensed drilling, which is described in more detail under "Exploration and Evaluation Expenses".

Depletion, depreciation, amortization and impairment expense increased by $2,501 million in 2019 compared to 2018, primarily due to a pre-tax impairment charge of $2,405 million recognized on certain crude oil and natural gas assets, which is described in more detail under "Depletion, Depreciation, Amortization and Impairment".

Other – net increased by $206 million in 2019 compared to 2018, primarily due to profit or loss elimination between segments.

Financial items increased by $63 million in 2019 compared to 2018, primarily due to higher finance expenses arising from the adoption of IFRS 16 in 2019.

Recovery of income taxes increased by $707 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

Average Sales Prices Realized

Average Sales Prices Realized	2019	2018
Crude oil and NGL *($/bbl)*		
Light & Medium crude oil	**72.85**	83.71
NGL[(1)]	**44.99**	55.72
Heavy crude oil	**54.70**	39.26
Bitumen	**49.00**	30.17
Total crude oil and NGL average	**52.28**	42.16
Natural gas average *($/mcf)*[(1)]	**6.44**	6.64
Total average *($/boe)*	**48.37**	41.50

(1) Reported average NGL and conventional natural gas prices include Husky's working interest production from the BD Project (40%). 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 increased by 24% in 2019 compared to 2018, primarily due to the narrowing of the Canadian light/heavy oil differential, partially offset by the lower global benchmark crude oil prices.

The average sales prices realized by the Company for natural gas production decreased by 3% in 2019 compared to 2018, primarily due to lower production from the Liwan Gas Project.

Daily Gross Production

Daily Gross Production	2019	2018
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light and Medium crude oil	**8.5**	9.4
NGL	**12.7**	12.0
Heavy crude oil	**30.2**	36.8
Bitumen[(1)]	**128.8**	124.2
	180.2	182.4
Atlantic		
White Rose and Satellite Fields – light crude oil	**12.3**	17.4
Terra Nova – light crude oil	**4.1**	4.0
	16.4	21.4
Asia Pacific		
Liwan – NGL[(2)]	**7.4**	8.4
Madura – NGL[(3)]	**2.5**	2.5
	9.9	10.9
	206.5	214.7
Conventional natural gas *(mmcf/day)*		
Western Canada	**297.5**	291.0
Asia Pacific		
Liwan[(2)]	**171.0**	184.8
Madura[(3)]	**32.4**	31.2
	203.4	216.0
	500.9	507.0
Total *(mboe/day)*	**290.0**	299.2

(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%).
(3) Reported production volumes include Husky's working interest production from the BD Project (40%). 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 8.2 mbbls/day, or 4%, in 2019 compared to 2018. The decrease was primarily due to a reduction of heavy crude oil production due to government-mandated production quotas in Alberta and natural declines, combined with lower production from Atlantic due to the suspension of production from the White Rose field. The decreases were partially offset by increased bitumen production from the Company's Saskatchewan thermal projects in Lloydminster.

Conventional Natural Gas Production

Conventional natural gas production decreased by 6.1 mmcf/day, or 1%, in 2019 compared to 2018, primarily due to lower production from the Liwan Gas Project. The decrease was partially offset by the higher production at the Rainbow Lake development.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	2019	2018
Crude oil and NGL		
Light & Medium crude oil	**13**	22
NGL[(1)]	**7**	10
Heavy crude oil	**12**	11
Bitumen	**45**	29
Crude oil and NGL	**77**	73
Natural gas[(1)]	**23**	28
Total	**100**	100

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

2020 Production Guidance and 2019 Actual

	Guidance	Year ended December 31	Guidance
Gross Production	2020	2019	2019
Canada			
Light & Medium crude oil *(mbbls/day)*	23 - 25	**25**	29 - 31
NGL *(mbbls/day)*	12 - 13	**13**	12 - 13
Heavy crude oil & bitumen *(mbbls/day)*	169 - 178	**159**	155 - 163
Conventional Natural gas *(mmcf/day)*	270 - 280	**298**	297 - 307
Canada total *(mboe/day)*	249 - 263	**246**	246 - 258
Asia Pacific			
NGL *(mbbls/day)*[(1)]	9 - 11	**10**	9 - 10
Natural gas *(mmcf/day)*[(1)]	210 - 220	**203**	210 - 220
Asia Pacific total *(mboe/day)*	44 - 48	**44**	44 - 47
Total *(mboe/day)*	295 - 310	**290**	290 - 305

[(1)] *Includes Husky's working interest production from the BD Project (40%). 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, 2019 was at the low end of production guidance, primarily due to the factors that impacted crude oil and NGL production discussed above. The 2020 production guidance reflects a curtailment assumption of 5 mbbls/d for the first half of the year.

Factors that could potentially impact the Company's production performance in 2020 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 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, 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)*	**2019**	2018
Western Canada	**7**	9
Atlantic	**9**	8
Asia Pacific[(1)]	**7**	7
Total	**7**	8

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

The total royalty rate decreased in 2019, primarily due to lower royalty rates from thermal developments as a result of a change to the pre-payout status of a thermal property in the first quarter of 2019, combined with lower royalty rates from Western Canada as a result of a gas cost allowance credit in the third quarter of 2019. The decrease was partially offset by increased royalty rates for Atlantic due to a higher proportion of production from the Terra Nova field, which has a higher royalty rate.

Operating Costs

Operating Costs *($ millions)*	**2019**	2018
Western Canada	**1,296**	1,218
Atlantic	**252**	213
Asia Pacific	**96**	95
Total	**1,644**	1,526
Per unit operating costs *($/boe)*	**15.53**	14.00

Total Exploration and Production operating costs were $1,644 million in 2019 compared to $1,526 million in 2018. Total per unit operating costs averaged $15.53/boe in 2019 compared to $14.00/boe in 2018. The increase in per unit operating costs was primarily due to the factors discussed below.

Per unit operating costs in Atlantic averaged $42.20/bbl in 2019 compared to $27.21/bbl in 2018. The increase in per unit operating costs was primarily due to the costs associated with the flowline repair and well workover costs at the White Rose field, combined with lower production.

Per unit operating costs in Western Canada averaged $15.44/boe in 2019 compared to $14.48/boe in 2018. The increase in per unit operating costs was primarily due to higher energy and transportation costs, combined with lower production.

Per unit operating costs in Asia Pacific averaged $6.03/boe in 2019 compared to $5.53/boe in 2018. The increase in per unit operating costs was primarily due to lower production in 2019.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses *($ millions)*	**2019**	2018
Seismic, geological and geophysical	**131**	102
Expensed drilling	**409**	41
Expensed land	**7**	6
Total	**547**	149

Exploration and Evaluation expenses were $547 million in 2019 compared to $149 million in 2018. The increase in expensed drilling was primarily due to a pre-tax write-down of $339 million related to certain crude oil assets in Atlantic and Western Canada. The write-down was primarily due to changes in management's future development plans resulting from sustained declines in forecasted short and long-term crude oil prices.

Depletion, Depreciation, Amortization and Impairment

During 2019, the Company recognized a pre-tax impairment charge of $2,405 million within the Sunrise Energy Project, Western Canada and Atlantic. The impairment charge, reflected in the fourth quarter of 2019, was primarily due to sustained declines in forecasted short and long-term crude oil and natural gas prices and management's decision to reduce capital investment in these areas.

In 2019, total DD&A excluding impairment averaged $18.46/boe compared to $16.99/boe in 2018.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were lower in 2019 compared to 2018, as further described below. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1] *($ millions)*	2019	2018
Exploration		
Western Canada	**3**	99
Thermal developments	**16**	7
Non-thermal developments	**1**	—
Atlantic	**19**	73
Asia Pacific[2]	**7**	52
	46	231
Development		
Western Canada	**189**	332
Thermal developments	**748**	874
Non-thermal developments	**117**	110
Atlantic	**906**	916
Asia Pacific[2]	**340**	148
	2,300	2,380
Acquisitions		
Western Canada	**—**	4
Thermal developments	**—**	41
	—	45
Total	**2,346**	2,656

(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 2019, $192 million (8%) was invested in Western Canada compared to $435 million (16%) in 2018. Capital expenditures in 2019 related primarily to resource play development targeting the Montney Formation.

Thermal Developments

During 2019, $764 million (33%) was invested in thermal developments compared to $922 million (35%) in 2018. Capital expenditures in 2019 related primarily to the construction work at the Dee Valley, Spruce Lake Central and Spruce Lake North thermal projects.

Non-Thermal Developments

During 2019, $118 million (5%) was invested in non-thermal developments compared to $110 million (4%) in 2018. Capital expenditures in 2019 related primarily to drilling and advancing the Company's EOR program, particularly the Aberfeldy Polymer Project.

Atlantic

During 2019, $925 million (39%) was invested in Atlantic compared to $989 million (37%) in 2018. Capital expenditures in 2019 related primarily to the development of the West White Rose Project and sustainment and development activities at the White Rose field.

Asia Pacific

During 2019, $347 million (15%) was invested in Asia Pacific compared to $200 million (8%) in 2018. Capital expenditures in 2019 related primarily to the continued development of Liuhua 29-1.

Exploration and Production Wells Drilled

Onshore Drilling Activity

The following table discloses the number of wells drilled during 2019 and 2018:

Wells Drilled *(wells)*[(1)]	**2019**		2018	
	Gross	**Net**	Gross	Net
Thermal developments	**68**	**65**	150	140
Non-thermal developments	**47**	**47**	31	26
Western Canada	**21**	**17**	46	45
Total	**136**	**129**	227	211

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

Offshore Drilling Activity

The following table discloses the Company's Offshore drilling activity during 2019:

Region	Well	Working Interest	Well Type
Atlantic	E-18 13	72.5%	Development
Atlantic	E-18 14	72.5%	Development
Atlantic	Tiger's Eye D-17	40%	Exploration
Asia Pacific	LH 29-1-A3	75%	Development
Asia Pacific	LH 29-1-A1	75%	Development
Asia Pacific	LH 29-1-A2	75%	Development

2020 Upstream Capital Expenditures Program

2020 Upstream Capital Expenditures Program *($ millions)*	
Thermal developments	**1,050 - 1,100**
Non-thermal developments and Western Canada	**225 - 250**
Atlantic	**1,075 - 1,150**
Asia Pacific[(1)]	**275 - 300**
Total Upstream capital expenditures	**2,625 - 2,800**

(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 2020 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. 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 $1,050 - $1,100 million in thermal developments for 2020, primarily for the development of the Spruce Lake North, Spruce Lake Central and Spruce Lake East thermal bitumen projects. The Company is making progress in its strategy to transition a greater percentage of production to long-life thermal bitumen production and the 2020 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted $225 - $250 million in non-thermal developments and Western Canada for 2020, primarily for the planned EOR, consisting of polymer flooding at Golden Lake and horizontal drilling, drilling activities in the Spirit River and Montney formations, and sustainment and maintenance activities.

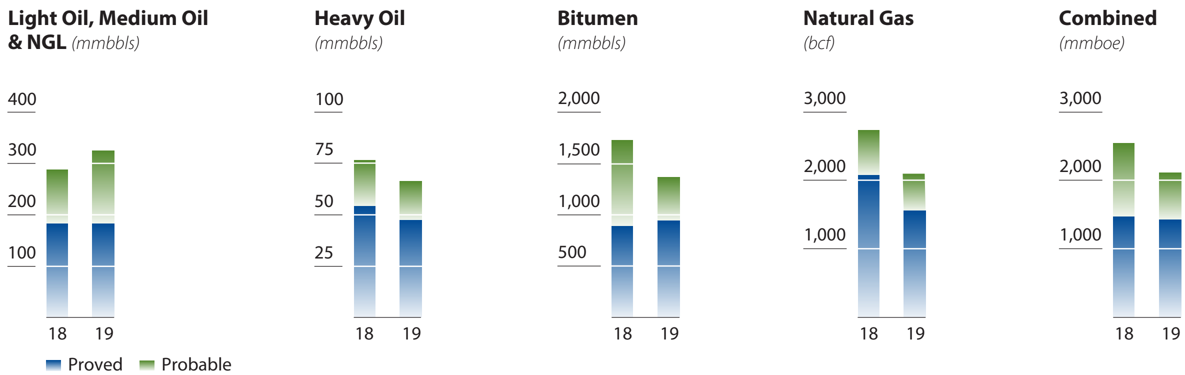
The Company has budgeted $1,075 - $1,150 million in Atlantic for 2020, primarily for the construction of the West White Rose Project.

The Company has budgeted $275 - $300 million in Asia Pacific for 2020, 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, 2019 with a preparation date of January 31, 2020.

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 for the year ended December 31, 2019, 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 and on the Company's website at www.huskyenergy.com.

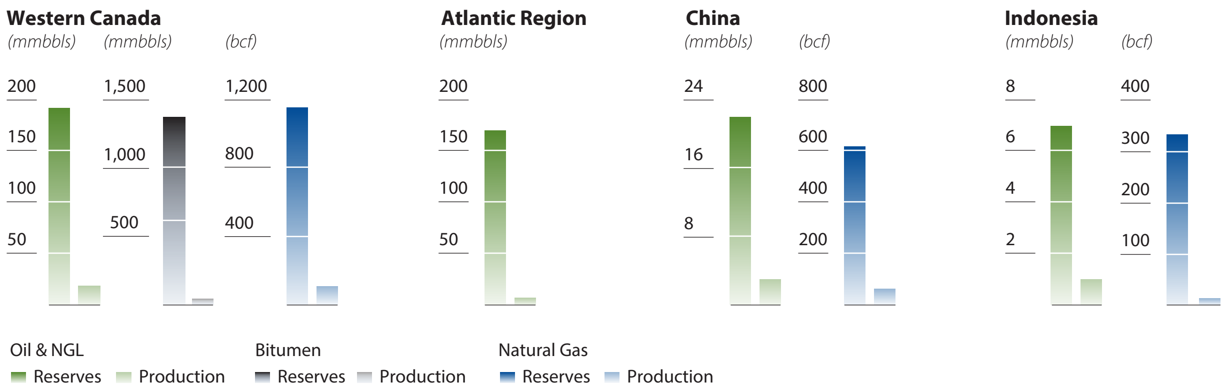
Sproule Associates Limited ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit and review of the Company's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion on January 31, 2020 stating that the Company's 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, 2019, the Company's proved oil and gas reserves were 1,431 mmboe, down from 1,471 mmboe at the end of 2018. The Company's 2019 reserves replacement ratio, defined as net additions of proved reserves divided by total production during the period, was 67% excluding economic revisions (62% including economic revisions).

Major changes to proved reserves in 2019 included:

- Western Canada Extensions & Improved Recovery additions of 168 mmboe which included 40 mmbbls from one new and 35 mmbbls from three existing Lloydminster bitumen SAGD projects (16 mmbbls transferred from probable reserves), 20 mmbbls at the Tucker Thermal Project (transferred from probable reserves), 15 mmbbls at the Sunrise Energy Project and 38 mmboe from Wembley (including 111 bcf of conventional natural gas and 19 mmbbls of NGL) and 5 mmboe from Wapiti from new locations.
- Discoveries included 27 bcf of conventional natural gas and 1 mmbbls of NGL for Liuhua 29-1 transferred from probable reserves as Technical Revisions.
- Western Canada Technical Revisions are associated with the updated long-term strategic plan where less liquid-rich gas plays are no longer funded. This resulted in a reduction of proved undeveloped reserves of 443 bcf (90% of the Technical Revisions) of conventional natural gas and 5 mmbbls of NGL.
- Economic Factors of 5 mmboe are mainly associated with lower gas prices in Western Canada.

Proved Plus Probable Reserves and Production at December 31, 2019:



Reconciliation of Proved Reserves[1]

(forecast prices and costs before royalties)	Canada – Western Canada – Light/ Medium Crude Oil & NGL (mmbbls)	Canada – Western Canada – Heavy Crude Oil (mmbbls)[2]	Canada – Western Canada – Bitumen (mmbbls)[2]	Canada – Western Canada – Conventional Natural Gas (bcf)	Canada – Atlantic – Light Crude Oil (mmbbls)	International – Light Crude Oil & NGL (mmbbls)	International – Conventional Natural Gas (bcf)	Total – Crude Oil, Bitumen & NGL (mmbbls)	Total – Conventional Natural Gas (bcf)	Total – Equivalent Units (mmboe)
Proved reserves										
December 31, 2018	65	54	890	1,288	93	24	783	1,126	2,071	1,471
Technical revisions	(7)	—	(13)	(496)	(2)	1	1	(21)	(495)	(103)
Acquisitions	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	25	6	113	147	—	1	27	145	174	174
Economic factors	(1)	(1)	—	(15)	—	—	—	(2)	(15)	(5)
Production	(7)	(12)	(47)	(109)	(6)	(4)	(74)	(76)	(183)	(106)
Proved reserves December 31, 2019	**75**	**47**	**943**	**815**	**85**	**22**	**737**	**1,172**	**1,552**	**1,431**
Proved and probable reserves December 31, 2019	**126**	**66**	**1,366**	**1,155**	**169**	**28**	**948**	**1,755**	**2,103**	**2,105**
December 31, 2018	80	76	1,722	1,751	177	30	984	2,085	2,735	2,541

(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]

(forecast prices and costs before royalties)	Canada – Western Canada – Light/ Medium Crude Oil & NGL (mmbbls)	Canada – Western Canada – Heavy Crude Oil (mmbbls)[2]	Canada – Western Canada – Bitumen (mmbbls)[2]	Canada – Western Canada – Conventional Natural Gas (bcf)	Canada – Atlantic – Light Crude Oil (mmbbls)	International – Light Crude Oil & NGL (mmbbls)	International – Conventional Natural Gas (bcf)	Total – Crude Oil, Bitumen & NGL (mmbbls)	Total – Conventional Natural Gas (bcf)	Total – Equivalent Units (mmboe)
Proved developed reserves										
December 31, 2018	56	53	142	804	24	20	528	295	1,332	517
Technical revisions	—	—	19	(49)	(2)	—	22	17	(27)	13
Transfer from proved undeveloped	2	1	51	36	5	—	—	59	36	65
Acquisitions	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—
Discoveries, extensions and improved recovery	5	5	3	41	—	—	—	13	41	19
Economic factors	(1)	(1)	—	(14)	—	—	—	(2)	(14)	(4)
Production	(7)	(12)	(47)	(109)	(6)	(4)	(74)	(76)	(183)	(106)
December 31, 2019	**55**	**46**	**168**	**709**	**21**	**16**	**476**	**306**	**1,185**	**504**

(1) *Numbers 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)*	**2019**	2018
Gross revenues	**2,342**	2,211
Marketing and other	**189**	668
Expenses		
Purchases of crude oil and products	**2,336**	2,087
Production, operating and transportation expenses	**21**	23
Selling, general and administrative expenses	**9**	5
Depletion, depreciation, amortization and impairment	**12**	—
Other – net	**—**	2
Share of equity investment gain	**(9)**	(18)
Financial items	**3**	—
Provisions for income taxes	**43**	213
Net earnings	**116**	567

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $131 million and $249 million, respectively, in 2019 compared to 2018, primarily due to increased prices and additional costs incurred on the construction of the Saskatchewan Gathering System Expansion in 2019.

Marketing and other decreased by $479 million in 2019 compared to 2018, primarily due to the tightening of location differentials between Canada and the U.S.

Provisions for income taxes decreased by $170 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

4.3 Downstream

Upgrading

Upgrading Earnings Summary *($ millions, except where indicated)*	2019	2018
Gross revenues	**1,777**	1,750
Expenses		
Purchases of crude oil and products	**1,303**	928
Production, operating and transportation expenses	**217**	195
Selling, general and administrative expenses	**9**	7
Depletion, depreciation, amortization and impairment	**115**	123
Financial items	**1**	1
Provisions for income taxes	**35**	135
Net earnings	**97**	361
Upgrading throughput *(mbbls/day)*[(1)]	**74.9**	75.6
Total sales *(mbbls/day)*	**75.2**	74.7
Synthetic crude oil sales *(mbbls/day)*	**55.4**	52.9
Upgrading differential *($/bbl)*	**17.19**	29.05
Unit margin *($/bbl)*	**17.27**	30.15
Unit operating cost *($/bbl)*[(2)]	**7.94**	7.07

(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 and diesel.

Upgrading gross revenues increased by $27 million in 2019 compared to 2018, primarily due to higher synthetic crude sales volumes, partially offset by lower realized prices for synthetic crude oil. The price of Husky Synthetic Blend averaged $74.35/bbl in 2019 compared to $75.55/bbl in 2018.

Upgrading purchases of crude oil and products increased by $375 million in 2019 compared to 2018, primarily due to an increase in the average cost of heavy crude oil feedstock driven by tighter light/heavy oil differential, partially offset by lower throughput volumes in 2019.

Provisions for income taxes decreased by $100 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	**2019**	2018
Gross revenues	**3,122**	3,412
Expenses		
Purchases of crude oil and products	**2,571**	2,760
Production, operating and transportation expenses	**278**	265
Selling, general and administrative expenses	**53**	47
Depletion, depreciation, amortization and impairment	**218**	115
Gain on sale of assets	**(6)**	(2)
Other – net	**—**	(1)
Financial items	**15**	12
Provisions for (recovery of) income taxes	**(2)**	58
Net earnings (loss)	**(5)**	158
Number of fuel outlets[(1)]	**553**	557
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.4**	7.7
Fuel sales per retail outlet *(thousands of litres/day)*	**12.7**	12.3
Refinery throughput		
Prince George Refinery *(mbbls/day)*[(2)(3)]	**7.2**	10.7
Lloydminster Refinery *(mbbls/day)*[(2)]	**26.4**	27.1
Ethanol production *(thousands of litres/day)*	**823.0**	819.4

(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.*
(3) *Sale of the Prince George Refinery closed on November 1, 2019.*

Canadian Refined Products gross revenues decreased by $290 million in 2019 compared to 2018, primarily due to lower product prices and lower sales volumes.

Canadian Refined Products purchases of crude oil and products decreased by $189 million in 2019 compared to 2018, primarily due to lower throughput volumes resulting primarily from a planned turnaround at the Prince George Refinery in the second quarter of 2019, combined with lower commodity prices.

Depletion, depreciation, amortization and impairment expense increased by $103 million in 2019 compared to 2018, primarily due to a pre-tax impairment charge of $90 million recognized on the Lloyd Ethanol Plant and Minnedosa Ethanol Plant. The impairment charge in 2019 was a result of sustained declines in forecasted ethanol margins.

Recovery of income taxes increased by $60 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	2019	2018
Gross revenues	**9,940**	11,770
Expenses		
Purchases of crude oil and products	**8,629**	10,334
Production, operating and transportation expenses	**869**	795
Selling, general and administrative expenses	**33**	22
Depletion, depreciation, amortization and impairment	**735**	450
Loss on sale of assets	**1**	—
Other – net	**(654)**	(464)
Financial items	**18**	14
Provisions for income taxes	**69**	138
Net earnings	**240**	481
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*(1)	**136.4**	151.1
BP-Husky Toledo Refinery throughput *(mbbls/day)*(1)(2)	**63.1**	71.1
Superior Refinery throughput *(mbbls/day)*(1)	**—**	11.7
Refining and marketing margin *(US$/bbl crude throughput)*	**13.83**	13.03
Refinery inventory *(mmbbls)*(3)	**5.0**	6.9

(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%).*
(3) *Feedstock and refined products are included in refinery inventory.*

U.S. Refining and Marketing gross revenues decreased by $1,830 million in 2019 compared to 2018, primarily due to lower sales volume at the Lima and BP-Husky Toledo refineries, both of which completed planned turnarounds in 2019, and no sales volume at the Superior Refinery in 2019.

U.S. Refining and Marketing purchases of crude oil and products decreased by $1,705 million in 2019 compared to 2018, primarily due to lower throughput volumes at the Lima and BP-Husky Toledo refineries, both of which completed planned turnarounds in 2019, combined with the realization of lower cost crude oil feedstock, from late 2018, at the Lima Refinery, during the first quarter of 2019.

Production, operating and transportation expenses increased by $74 million in 2019 compared to 2018, primarily due to planned turnarounds at the Lima and BP-Husky Toledo Refineries in 2019.

Depletion, depreciation, amortization and impairment expense increased by $285 million in 2019 compared to 2018, primarily due to a pre-tax derecognition of $254 million on the carrying value of components replaced as part of the crude oil flexibility project at the Lima Refinery.

Other – net income increased by $190 million in 2019 compared to 2018, primarily due to pre-tax insurance recoveries for rebuild costs, incident costs and business interruption associated with the incident at the Superior Refinery.

Provisions for income taxes decreased by $69 million in 2019 compared to 2018, primarily due to lower earnings before income taxes in 2019.

Downstream Capital Expenditures

In 2019, Downstream capital expenditures totalled $946 million compared to $801 million in 2018. In Canada, capital expenditures of $178 million related primarily to a polymer modified asphalt project at the Lloydminster Refinery and the planned turnaround at the Prince George Refinery. In the U.S., capital expenditures of $768 million related primarily to the crude oil flexibility project at the Lima Refinery and costs related to the turnaround at the BP-Husky Toledo Refinery.

4.4 Corporate

Corporate Summary *($ millions) income (expense)*	2019	2018
Production, operating and transportation expenses	**2**	2
Selling, general and administrative expenses	**(292)**	(277)
Depletion, depreciation, amortization and impairment	**(104)**	(92)
Other – net	**16**	8
Net foreign exchange gain	**44**	14
Finance income	**71**	52
Finance expense	**(151)**	(178)
Recovery of income taxes	**302**	138
Net loss	**(112)**	(333)

The Corporate segment reported a net loss of $112 million in 2019 compared to a net loss of $333 million in 2018. The change was primarily due to the recognition of $233 million in tax recoveries related to the reduction in the Alberta provincial corporate tax rate that was substantively enacted in the second quarter of 2019.

Finance expense decreased by $27 million in 2019 compared to 2018, primarily due to lower interest expenses on long-term debt in 2019.

Net foreign exchange gain increased by $30 million due to the items noted below.

Foreign Exchange Summary *($ millions, except where indicated)*	2019	2018
Non-cash working capital gain (loss)	**17**	(3)
Other foreign exchange gain	**27**	17
Net foreign exchange gain	**44**	14
U.S./Canadian dollar exchange rates:		
At beginning of year	**US$0.733**	US$0.799
At end of year	**US$0.771**	US$0.733

Included in the other foreign exchange gain 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)*	2019	2018
Provisions for (recovery of) income taxes	**(799)**	471
Cash income taxes paid	**41**	37

Consolidated income taxes were a recovery of $799 million in 2019 compared to a provision of $471 million in 2018. The increase in recovery of income taxes was primarily due to a $741 million deferred income tax recovery associated with impairment, derecognition and exploration asset write-down charges recognized on crude oil and natural gas, and refinery assets located in Canada and United States, and $233 million in deferred income tax recovery related to the reduction in the Alberta provincial corporate tax rate that was substantively enacted in the second quarter of 2019.

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 and Safety Incidents

The Company's businesses are subject to inherent operational risks which have the potential to impact safety, the environment, its assets and its reputation. In general, the Company's operations are subject to operational risks, including, but not limited to: fires, loss of containment, blowouts, power outages, freeze-ups and other similar events; oil and natural gas leaks; encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; uncontrollable flows of oil, natural gas and well fluids; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances onto trucks; release of tailings or harmful substances into a water system; the breakdown or failure of equipment, pipelines and facilities, information systems and processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); releases or spills from shipping vessels; failure to maintain adequate supplies of spare parts; the compromise of information technology and control systems and related data; operator error; labour disputes; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of the company's facilities and pipelines; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, explosions, acts of sabotage and other similar events.

Failure to manage the hazards and associated risks effectively could result in potential fatalities, environmental impacts, interruptions to activities or use of assets, or loss of license to operate. 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 conventional natural gas production. Lower prices for crude oil, NGL and conventional 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 often 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 various grades of crude oil may be constrained from time to time, creating the need for additional 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 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 conventional natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's conventional 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 conventional 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.

Commodity Price Risk

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, to manage exposure to price volatility on a portion of its refined product, oil and gas production, and 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 Company's results will be impacted by a decrease in the price of crude oil and natural gas inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. Due to the integrated nature, the Company has a natural partial mitigation to the WCS differential risk. The Company also has natural gas inventory that could have an impact on earnings based on changes in natural gas prices. All these inventories are subject to a lower of cost or net realizable value test on a quarterly basis.

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, conventional 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. The risk to employees and board members due to social unrest in Hong Kong is being managed through reduced travel and increased awareness and monitoring of the situation. The potential for detention and/or incarceration of the Company's employees/contractors entering into or working in China has increased, and as a result, review and reconsideration for travel into China has become a business/corporate process.

The Company does not own proved or probable reserves in or near areas of armed conflict. According to the Uppsala Conflict Data Program, armed conflict is defined as "contested incompatibility that concerns government and/or territory over which the use of armed force between the military forces of two parties, of which at least one is the government of a state, has resulted in at least 25 battle-related deaths each year."

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, climate change and the impacts thereof, 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 or jointly control 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 conventional 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% of the future net revenue discounted at 10% 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 Risks

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 of, formulation of or demand for the Company's products, which may or may not be offset through market pricing.

The Company anticipates that further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and approval delays for critical licences and permits. Public interest in environmental, social and governance issues has also increased significantly in recent years, as evidenced by the large number of signatories to the United Nations Principles for Responsible Investment.

It is not possible to accurately forecast the amount of additional investment in new or existing facilities required in the future for environmental protection or to address all new regulatory compliance requirements, such as reporting.

Climate Change Risks

Regulatory

Climate change regulations may become more onerous over time as governments implement policies to further reduce greenhouse gases ("GHG") emissions. 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. Costs associated with levy payments for emerging climate change regulations may be significant.

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. A Proposed Regulatory Approach for the CFS was published in June 2019 and proposed regulations are expected to be published in Canada Gazette, Part I for early 2020. The final regulations for liquid fuels are planned for early 2021, with the regulations expected to come into force in 2022. Due to the uncertainty of the gaseous and solid fuel regulations, the full impact of the CFS is still unknown.

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 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 emissions 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 Company complies with the Renewable Fuel Standard ("RFS") program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the "blend wall" (the 10% limit prescribed by most automobile warranties), the price and availability of RINs have been volatile. 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.

Climatic Conditions

Extreme climatic conditions may also 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 NL. 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 NL may threaten Atlantic oil production facilities, cause damage to equipment and possible production disruptions, spills, other asset damage and human impacts.

Transition

In addition to emissions regulations and the physical risks of climate change, climate-related transition risks could have a material adverse effect on the Company's business, financial condition and results of operations, and could adversely impact the Company's reputation. For example, increased public opposition to companies in the oil sands industry could lead to constrained access to insurance, liquidity and capital and changes in demand for the Company's products, which may impact revenue. Any increases in GHG emissions by the Company could lead to additional taxes and levies, which would increase the costs associated with certain projects. The potential need to develop new technologies to reduce the intensity of GHG emissions could require significant capital investment. Further, the Company may become subject to climate change litigation initiated by third parties. The Company's management monitors these risks and reports to the Board through management's Enterprise Risk Management framework.

Overall, the Company is not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and transition risks could impact the Company's financial and operating results.

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.

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.

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.

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.

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)

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.

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 Board 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. 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 the Company's 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.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

Cash Flow Summary ($ millions)	2019	2018
Cash flow		
Operating activities	**2,971**	4,134
Financing activities	**(817)**	(325)
Investing activities	**(3,197)**	(3,521)

Cash Flow from Operating Activities

Cash flow generated from operating activities decreased by $1,163 million in 2019 compared to 2018. The decrease was primarily due to the tightening of the location differentials between Canada and the U.S., combined with lower Upstream and U.S. Refining volumes.

Cash Flow used for Financing Activities

Cash flow used for financing activities increased by $492 million in 2019 compared to 2018. Financing activities in 2019 related primarily to higher common share dividend payments, combined with higher finance expenses arising from the adoption of IFRS 16 in 2019.

Cash Flow used for Investing Activities

Cash flow used for investing activities decreased by $324 million in 2019 compared to 2018. The decrease was primarily due to proceeds from the sale of the Prince George Refinery and decreased capital expenditures in 2019.

6.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2019, the Company's working capital was $302 million compared to $694 million at December 31, 2018. A reconciliation of the Company's working capital is as follows:

Working Capital ($ millions)	December 31, 2019	December 31, 2018	Change
Cash and cash equivalents	**1,775**	2,866	(1,091)
Accounts receivable	**1,499**	1,355	144
Income taxes receivable	**30**	112	(82)
Inventories	**1,486**	1,232	254
Prepaid expenses	**148**	123	25
Accounts payable and accrued liabilities	**(3,465)**	(3,159)	(306)
Short-term debt	**(550)**	(200)	(350)
Long-term debt due within one year	**(400)**	(1,433)	1,033
Lease liabilities	**(109)**	—	(109)
Asset retirement obligations	**(112)**	(202)	90
Net working capital	**302**	694	(392)

The decrease in cash and cash equivalents was primarily due to lower cash flow from operating activities. Fluctuations in accounts receivable and accounts payable were due to the timing of settlements in 2019 compared to 2018. The increase in inventories was primarily driven by the higher commodity prices at the end of 2019 compared to 2018, and a higher volume of crude oil feedstock inventory in U.S Refining and Marketing at the end of 2019 compared to 2018. The increase in short-term debt was due to increased borrowings on commercial paper. The decrease in long-term debt due within one year was due to the timing of debt maturities. The increase in lease liabilities was due to the adoption of IFRS 16 in 2019.

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, 2019, the Company had the following available credit facilities:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities[(1)]	**900**	**464**
Syndicated credit facilities[(2)]	**4,000**	**3,450**
	4,900	**3,914**

(1) *Consists of demand credit facilities.*

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

At December 31, 2019, the Company had $3,914 million of unused credit facilities of which $3,450 million are long-term committed credit facilities and $464 million are short-term uncommitted credit facilities. A total of $436 million short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $550 million of long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2019, the Company had no direct borrowing against committed credit facilities. The maturity dates for the Company's revolving syndicated credit facilities are June 19, 2022 and March 9, 2024. 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. These covenants are used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2019, 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, 2019.

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. 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.

On March 15, 2019, the Company issued US$750 million in senior unsecured notes. The notes bear an annual interest rate of 4.40% and are due on April 15, 2029. The Company raised the net proceeds of the offering for general corporate purposes, which included the repayment of certain outstanding debt securities that matured in 2019.

On May 1, 2019, the Company filed a universal short form base shelf prospectus (the "2019 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 June 1, 2021. The 2019 Canadian Shelf Prospectus replaced the Company's Canadian universal short form base shelf prospectus which expired on April 30, 2019. During the 25-month period that the 2019 Canadian Shelf Prospectus is in effect, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On June 17, 2019, the Company repaid the maturing 6.15% notes. The amount paid to note holders was $402 million.

On December 16, 2019, the Company repaid the maturing 7.25% notes. The amount paid to note holders was $987 million.

As at December 31, 2019, the Company had $3.0 billion in unused capacity under the 2019 Canadian Shelf Prospectus and US$2.25 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 2019 Canadian Shelf Prospectus and the 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net Debt

The Company had total debt of $5,520 million and cash and cash equivalents of $1,775 million at December 31, 2019, compared to total debt of $5,747 million and cash and cash equivalents of $2,866 million at December 31, 2018. The Company's net debt at December 31, 2019 increased by $864 million when compared to December 31, 2018:

Net Debt[1] *($ millions)*	**December 31, 2019**	December 31, 2018
Net debt at beginning of period	**(2,881)**	(2,927)
Change in net debt due to:		
Funds from operations[1]	**3,251**	4,004
Long-term debt issuance	**1,000**	—
Long-term debt repayment	**(1,389)**	—
Short-term debt issuance, net	**350**	—
Debt issue costs	**(9)**	—
Dividends on common shares	**(503)**	(402)
Dividends on preferred shares	**(35)**	(35)
Finance lease payments	**(233)**	—
Capital expenditures	**(3,432)**	(3,578)
Capitalized interest	**(177)**	(108)
Corporate acquisition	**—**	(15)
Proceeds from asset sales	**277**	4
Investment in joint ventures	**(40)**	(40)
Change in non-cash working capital	**(104)**	485
Other	**1**	(27)
Effect of exchange rates on cash and cash equivalents	**(48)**	65
Effect of exchange rates on long-term debt	**227**	(307)
	(864)	46
Net debt at end of period	**(3,745)**	(2,881)

[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, 2019 and 2018, the Company's capital expenditures were primarily 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.

6.4 Capital Structure

Capital Structure ($ millions)	December 31, 2019 Outstanding
Total debt[(1)]	**5,520**
Shareholders' equity	**17,296**

[(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 $22.8 billion at December 31, 2019 (December 31, 2018 – $25.4 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 financing requirements and capital structure 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). At December 31, 2019, debt to capital employed was 24.2% (December 31, 2018 – 22.7%) and debt to funds from operations was 1.7 times (December 31, 2018 – 1.4 times). The Company is subject to a leverage covenant in its credit facilities that limits debt to capital (subject to specific definitions in the credit agreements) to less than 65%. The Company is in compliance with this covenant and considers the risk of non-compliance low. The Company also targets a debt to funds from operations ratio of less than 2.0 times over the longer term.

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)	2020	2021-2022	2023-2024	Thereafter	Total
Long-term debt and interest on fixed rate debt	612	1,040	1,303	3,775	6,730
Operating agreements[(1)]	75	155	155	666	1,051
Firm transportation agreements[(1)]	576	1,189	1,188	4,203	7,156
Unconditional purchase obligations[(2)]	2,224	3,212	2,305	5,143	12,884
Lease rentals and exploration work agreements	79	102	113	866	1,160
Obligations to fund equity investee[(3)]	54	141	149	359	703
Lease obligations[(4)]	205	340	313	2,174	3,032
Asset retirement obligations	112	253	244	9,371	9,980
	3,937	6,432	5,770	26,557	42,696

[(1)] *Included in the total of operating agreements and firm transportation agreements are blending and storage agreements and transportation commitments of $1.1 billion and $1.8 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 10 in the 2019 consolidated financial statements.*

During the three months ended December 31, 2019, the Company entered into a new agreement totaling an incremental $2.2 billion for a term of five years to purchase refined products for the purpose of supporting the retail network.

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, 2019, the Company has deposited funds of $142 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% 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, 2019, the Company charged HMLP $424 million related to construction costs and management services. For the year ended December 31, 2019, the Company had purchases from HMLP of $219 million related to the use of the pipeline for the Company's blending, transportation and storage activities. As at December 31, 2019, the Company had $143 million due from HMLP and $16 million due to HMLP.

6.7 Outstanding Share Data

Authorized:

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

Issued and outstanding: February 24, 2020

• 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	17,369,033
• stock options exercisable	9,586,551

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 2019 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, lease liabilities 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 results.

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. 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.

Change in Accounting Policy

Leases

In January 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which replaces the existing IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease is a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the balance sheet while operating leases were recognized in the Consolidated Statements of Income (Loss) when the expense was incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for most lease contracts. The recognition of the present value of the lease payments for certain contracts previously classified as operating leases resulted in increases to assets, liabilities, depletion, depreciation and amortization and finance expense, and a decrease to production, operating and transportation expense, purchases of crude oil and products and selling, general and administrative expenses.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Accordingly, comparative information in the Company's financial statements are not restated.

On adoption, lease liabilities were measured at the present value of the remaining lease payments discounted using the Company's incremental borrowing rate on January 1, 2019. Right-of-use assets were measured at an amount equal to the lease liability. For leases previously classified as operating leases, the Company applied the exemption not to recognize right-of-use assets and liabilities for leases with a lease term of less than 12 months, excluded initial direct costs from measuring the right-of-use asset at the date of initial application and applied a single discount rate to a portfolio of leases with similar characteristics. For leases that were previously classified as finance leases under IAS 17, the carrying amount of the lease asset and lease liability remain unchanged upon transition and were determined at the carrying amount immediately before adoption date. Additionally, instead of an impairment review, the Company adjusted the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application.

No adjustments were required upon transition to IFRS 16 for leases where the Company is a lessor. Under IFRS 16, the Company is required to assess the classification of a sub-lease with reference to the right-of-use asset, not the underlying asset. On transition, the Company reassessed the classification of any sub-lease contracts previously assessed under IAS 17. No changes to sublease classification or associated accounting treatment was required.

Financial Statement Impact

The recognition of the present value of lease payments resulted in an additional $1.3 billion of right-of-use assets and associated lease liabilities. The Company has recognized lease liabilities in relation to lease arrangements previously disclosed as operating lease commitments under IAS 17 that meet the criteria of a lease under IFRS 16. Upon recognition in the consolidated statement of financial position, the Company's weighted average incremental borrowing rate used in measuring lease liabilities was 3.58%.

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 2020 production guidance, including guidance for specified areas and product types; the Company's objective of maintaining stated debt to funds from operations; and the Company's 2020 Upstream capital expenditure program;
- with respect to the Company's thermal developments, the expected timing of first production from the Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central and Dee Valley 2 projects;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of construction activities, installation of the control system and connecting flow lines and first gas production at Liuhua 29-1; the expected timing of additional appraisal drilling at Block 15/33; the expected timing of drilling five MDA and two MBH field production wells, and the expected timing of first gas production and sales therefrom; the expected timing of development of a floating production unit to process gas at MDA and MBH; and plans to develop 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;
- with respect to the Company's Infrastructure and Marketing business, the expected timing of completion of construction of storage tanks at the Hardisty Terminal; and
- with respect to the Company's Downstream operating segment: plans to market and potentially sell the Retail and Commercial Fuels Network; the timing of ramp-up to full rates at the Lima Refinery; the expected investment in the rebuild of the Superior Refinery and anticipated insurance recoveries for property damage and lost income associated therewith; and the expected timing of resumption of full operations 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 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, 2019 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, 2019 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, 2019.

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% 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.

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 sustaining capital. 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 excluding 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, 2019, 2018 and 2017:

Debt to Funds from Operations *($ millions)*	**December 31, 2019**	December 31, 2018	December 31, 2017
Total debt	**5,520**	5,747	5,440
Funds from operations	**3,251**	4,004	3,306
Debt to funds from operations	**1.7**	1.4	1.6

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 excluding 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.

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 was 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		
($ millions)	**Dec. 31 2019**	Dec. 31 2018	**Dec. 31 2019**	Dec. 31 2018	Dec. 31 2017
Net earnings	**(2,341)**	216	**(1,370)**	1,457	786
Items not affecting cash:					
Accretion	**27**	25	**106**	97	112
Depletion, depreciation, amortization and impairment	**3,520**	662	**5,496**	2,591	2,882
Inventory write-down to net realizable value	**15**	60	**15**	60	—
Exploration and evaluation expenses	**332**	22	**355**	29	6
Deferred income taxes (recoveries)	**(789)**	25	**(974)**	396	(359)
Foreign exchange loss (gain)	**(11)**	1	**(26)**	(6)	(4)
Stock-based compensation	**(13)**	(50)	**(2)**	44	45
Gain on sale of assets	**(3)**	—	**(8)**	(4)	(46)
Unrealized market to market loss (gain)	**(13)**	(16)	**44**	(150)	56
Share of equity investment gain	**5**	(16)	**(59)**	(69)	(61)
Gain on insurance recoveries for damage to property	**(194)**	(253)	**(207)**	(253)	—
Other	**11**	2	**12**	21	16
Settlement of asset retirement obligations	**(90)**	(65)	**(276)**	(181)	(136)
Deferred revenue	**(14)**	(30)	**(42)**	(100)	(16)
Distribution from joint ventures	**27**	—	**187**	72	25
Change in non-cash working capital	**397**	730	**(280)**	130	398
Cash flow – operating activities	**866**	1,313	**2,971**	4,134	3,704
Change in non-cash working capital	**(397)**	(730)	**280**	(130)	(398)
Funds from operations	**469**	583	**3,251**	4,004	3,306
Capital expenditures	**(894)**	(1,265)	**(3,432)**	(3,578)	(2,220)
Free cash flow	**(425)**	(682)	**(181)**	426	1,086
Funds from operations – basic	**0.47**	0.58	**3.23**	3.98	3.29
Funds from operations – diluted	**0.47**	0.58	**3.23**	3.98	3.29

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, 2019, 2018 and 2017:

Net Debt *($ millions)*	**December 31, 2019**	December 31, 2018	December 31, 2017
Total debt	**5,520**	5,747	5,440
Cash and cash equivalents	**(1,775)**	(2,866)	(2,513)
Net debt	**3,745**	2,881	2,927

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, 2019, 2018 and 2017:

Total Debt *($ millions)*	**December 31, 2019**	December 31, 2018	December 31, 2017
Short-term debt	**550**	200	200
Long-term debt due within one year	**400**	1,433	—
Long-term debt	**4,570**	4,114	5,240
Total debt	**5,520**	5,747	5,440

Sustaining Capital

Sustaining capital is 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.

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 26, 2020. 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 26, 2020, should be read in conjunction with the 2019 consolidated financial statements and related notes. Readers are also encouraged to refer to the Company's interim reports filed for 2019, which contain Management's Discussion and Analysis and consolidated financial statements, and the Company's Annual Information Form for the year ended December 31, 2019, 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.

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, 2019 and 2018 and the Company's financial position at December 31, 2019 and 2018.

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*
Asphalt Refinery	*The asphalt refinery owned by the Company and located in Lloydminster, Alberta.*
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 excluding 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*
HOIMS	*The Husky Operational Integrity Management System*
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*
RIN	*Renewable Identification Numbers*
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*
Upgrader	*The heavy oil upgrading facility owned and operated by the Company and located in Lloydminster, Saskatchewan.*
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, 2019, 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, 2019, 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, 2019, 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 the effectiveness 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, 2019, 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

	Three months ended	
Fourth Quarter Results Summary	**Dec. 31**	Dec. 31
($ millions, except where indicated)	**2019**	2018
Gross revenues and Marketing and other		
Upstream		
Exploration and Production	**1,281**	643
Infrastructure and Marketing	**618**	678
Downstream		
Upgrading	**456**	307
Canadian Refined Products	**793**	821
U.S. Refining and Marketing	**2,222**	2,766
Corporate and Eliminations	**(489)**	(173)
Total gross revenues and marketing and other	**4,881**	5,042
Net earnings (loss)		
Upstream		
Exploration and Production	**(1,964)**	(206)
Infrastructure and Marketing	**(3)**	126
Downstream		
Upgrading	**48**	80
Canadian Refined Products	**(64)**	55
U.S. Refining and Marketing	**(192)**	213
Corporate and Eliminations	**(166)**	(52)
Net earnings (loss)	**(2,341)**	216
Per share – Basic	**(2.34)**	0.21
Per share – Diluted	**(2.34)**	0.16
Cash flow – operating activities	**866**	1,313
Funds from operations[(1)]	**469**	583
Per share – Basic	**0.47**	0.58
Per share – Diluted	**0.47**	0.58
Upstream		
Daily gross production		
Crude oil and NGL production *(mbbls/day)*[(2)]	**226.7**	214.7
Conventional natural gas production *(mmcf/day)*[(2)]	**507.4**	537.6
Total production *(mboe/day)*	**311.3**	304.3
Average sales prices realized *($/boe)*		
Crude oil and NGL *($/bbl)*[(2)]	**47.52**	18.93
Conventional natural gas *($/mcf)*[(2)]	**7.02**	6.86
Total average sales prices realized *($/boe)*	**46.06**	25.47
Downstream		
Refinery throughput		
Lloydminster Upgrader *(mbbls/day)*	**79.6**	71.8
Lloydminster Refinery *(mbbls/day)*	**28.2**	25.3
Prince George Refinery *(mbbls/day)*[(3)]	**3.9**	10.7
Lima Refinery *(mbbls/day)*	**21.4**	105.9
BP-Husky Toledo Refinery *(mbbls/day)*	**70.3**	73.2
Superior Refinery *(mbbls/day)*	**—**	—
Total throughput *(mbbls/day)*	**203.4**	286.9

	Three months ended	
Fourth Quarter Results Summary (continued)	**Dec. 31**	Dec. 31
($ millions, except where indicated)	**2019**	2018
Upgrading unit margin *($/bbl)*	**20.21**	29.13
Upgrading synthetic crude oil sales *(mbbls/day)*	**55.5**	53.8
Upgrading total sales *(mbbls/day)*	**78.0**	73.5
Retail fuel sales *(million of litres/day)*	**7.4**	8.0
Canadian light oil margins *($/litre)*	**0.032**	0.037
Lloydminster Refinery asphalt margin *($/bbl)*	**16.59**	41.50
U.S. Refining and Marketing margin *(US$/bbl crude throughput)*	**7.85**	9.12
U.S./Canadian dollar exchange rate *(US$)*	**0.758**	0.757

(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%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*
(3) *Prince George Refinery was sold on November 1, 2019.*

Gross Revenue and Marketing and Other

The Company's consolidated gross revenues and marketing and other decreased by $161 million in the fourth quarter of 2019 compared to the fourth quarter of 2018.

In the Upstream business segment, Exploration and Production gross revenues increased primarily due to higher average realized sales prices and production. Infrastructure and Marketing gross revenues and marketing and other decreased primarily due to the tightening of the location price differentials between Canada and the U.S. in 2019.

In the Downstream business segment, gross revenues decreased primarily due to lower throughput volumes as the Lima Refinery completed a planned turnaround in the fourth quarter of 2019.

Net Earnings (Loss)

The Company's consolidated net loss increased by $2,557 million in the fourth quarter of 2019 compared to the fourth quarter of 2018.

In the Upstream business segment, Exploration and Production net loss increased primarily due to an after-tax impairment charge of $1,822 million within the Sunrise Energy Project, Western Canada and Atlantic, combined with the same factors which impacted gross revenue and marketing and other.

In the Downstream business segment, U.S. Refining and Marketing net loss increased primarily due to an after-tax $198 million derecognition of the carrying value of components replaced as part of the crude oil flexibility project at the Lima Refinery, and Canadian Refined Products net loss increased primarily due to an after-tax impairment charge of $69 million recognized on the Lloyd Ethanol Plant and Minnedosa Ethanol Plant.

In the Corporate business segment, net earnings increased primarily due to work force adjustments during the fourth quarter of 2019.

Cash Flow – Operating Activities and Funds from Operations

Cash flow – operating activities and funds from operations decreased by $447 million and $114 million, respectively, in the fourth quarter of 2019 compared to the fourth quarter of 2018, primarily due to lower sales volume at the Lima Refinery, which completed a planned turnaround in the fourth quarter of 2019, tightening of location differentials between Canada and the U.S. and workforce adjustments.

Daily Gross Production

Production increased by 7.0 mbbls/day during the fourth quarter of 2019 compared to the fourth quarter of 2018 as a result of:
- Higher crude oil production from Atlantic due to higher production from the White Rose field, which resumed full production in mid-August 2019; and
- Higher bitumen production from the Company's thermal projects.

Partially offset by:
- Lower production from the Liwan Gas Project and BD Project; and
- Lower heavy crude oil production due to government-mandated production quotas in Alberta and natural declines.

Segmented Operational Information

Segmented Operational Information ($ millions, except where indicated)	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
Gross revenues and Marketing and other								
Upstream								
Exploration and Production	**1,281**	**1,241**	**1,252**	**1,184**	643	1,319	1,284	1,084
Infrastructure and Marketing	**618**	**711**	**634**	**568**	678	769	821	611
Downstream								
Upgrading	**456**	**464**	**457**	**400**	307	534	444	465
Canadian Refined Products	**793**	**871**	**804**	**654**	821	1,001	869	721
U.S. Refining and Marketing	**2,222**	**2,644**	**2,791**	**2,283**	2,766	3,198	3,035	2,771
Corporate and Eliminations	**(489)**	**(537)**	**(552)**	**(444)**	(173)	(521)	(470)	(390)
Total gross revenues and marketing and other	**4,881**	**5,394**	**5,386**	**4,645**	5,042	6,300	5,983	5,262
Net earnings (loss)								
Upstream								
Exploration and Production	**(1,964)**	**106**	**150**	**2**	(206)	214	158	57
Infrastructure and Marketing	**(3)**	**34**	**(38)**	**123**	126	149	154	138
Downstream								
Upgrading	**48**	**7**	**(2)**	**44**	80	88	84	109
Canadian Refined Products	**(64)**	**37**	**—**	**22**	55	43	32	28
U.S. Refining and Marketing	**(192)**	**126**	**134**	**172**	213	158	115	(5)
Corporate and Eliminations	**(166)**	**(37)**	**126**	**(35)**	(52)	(107)	(95)	(79)
Net earnings (loss)	**(2,341)**	**273**	**370**	**328**	216	545	448	248
Per share – Basic	**(2.34)**	**0.26**	**0.36**	**0.32**	0.21	0.53	0.44	0.24
Per share – Diluted	**(2.34)**	**0.25**	**0.36**	**0.31**	0.16	0.53	0.44	0.24
Cash flow – operating activities	**866**	**800**	**760**	**545**	1,313	1,283	1,009	529
Funds from operations[1]	**469**	**1,021**	**802**	**959**	583	1,318	1,208	895
Per share – Basic	**0.47**	**1.02**	**0.80**	**0.95**	0.58	1.31	1.20	0.89
Per share – Diluted	**0.47**	**1.02**	**0.80**	**0.95**	0.58	1.31	1.20	0.89
U.S./Canadian dollar exchange rate (US$)	**0.758**	**0.757**	**0.748**	**0.752**	0.757	0.765	0.775	0.791
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**33.3**	**30.5**	**19.6**	**16.5**	22.6	33.7	29.7	37.5
NGL[2]	**23.0**	**22.4**	**20.3**	**24.7**	24.8	24.5	21.8	20.5
Heavy crude oil	**32.6**	**31.6**	**28.9**	**27.6**	34.4	34.6	38.5	39.7
Bitumen	**137.8**	**126.4**	**120.4**	**130.3**	132.9	117.3	123.2	123.2
Total crude oil & NGL production *(mbbls/day)*	**226.7**	**210.9**	**189.2**	**199.1**	214.7	210.1	213.2	220.9
Conventional Natural gas *(mmcf/day)*[2]	**507.4**	**503.3**	**475.1**	**516.8**	537.6	519.5	494.0	477.0
Total production *(mboe/day)*	**311.3**	**294.8**	**268.4**	**285.2**	304.3	296.7	295.5	300.4
Average sales prices								
Light & Medium crude oil *($/bbl)*	**71.67**	**71.32**	**77.07**	**73.09**	60.19	93.84	92.23	82.08
NGL *($/bbl)*[2]	**45.72**	**38.39**	**50.22**	**46.07**	53.36	60.08	54.13	55.03
Heavy crude oil *($/bbl)*	**50.01**	**56.71**	**63.15**	**49.38**	18.71	50.09	54.22	32.80
Bitumen *($/bbl)*	**41.39**	**51.09**	**58.32**	**46.64**	5.42	46.00	44.41	27.77
Conventional natural gas *($/mcf)*[2]	**7.02**	**5.44**	**6.19**	**7.12**	6.86	6.15	6.53	7.03
Operating costs *($/boe)*	**15.25**	**14.83**	**15.83**	**16.30**	13.75	14.68	14.22	13.33
Operating netbacks[2][3]								
Lloydminster Thermal *($/bbl)*[4]	**31.19**	**38.25**	**44.34**	**34.50**	(0.05)	35.83	36.16	19.77
Lloydminster Non-Thermal *($/boe)*[4]	**11.54**	**14.92**	**22.32**	**10.83**	(11.80)	13.28	20.83	4.13
Tucker Thermal *($/bbl)*[4]	**28.01**	**41.46**	**47.25**	**33.50**	(5.08)	29.53	31.67	16.16
Sunrise Energy Project *($/bbl)*[4]	**10.61**	**26.37**	**32.85**	**14.54**	(25.60)	15.79	12.59	(5.62)
Western Canada – Crude Oil *($/bbl)*[4]	**(5.81)**	**10.49**	**(0.98)**	**15.58**	(1.70)	23.81	29.37	17.88
Western Canada – NGL & Conventional natural gas *($/mcf)*[5]	**0.68**	**(0.07)**	**(0.09)**	**1.06**	1.13	0.29	0.39	1.33
Atlantic – Light Oil *($/bbl)*[4]	**45.92**	**41.64**	**23.44**	**(16.82)**	23.19	68.20	57.79	65.23
Asia Pacific – Light Oil, NGL & Conventional natural gas *($/boe)*[2][4]	**69.12**	**62.59**	**68.07**	**68.33**	67.42	65.45	68.44	70.31
Total *($/boe)*[4]	**27.48**	**29.31**	**33.61**	**27.69**	9.42	31.30	31.31	24.37

Segmented Operational Information (continued)	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
Upgrading								
Synthetic crude oil sales *(mbbls/day)*	**55.5**	**58.5**	**54.1**	**53.5**	53.8	54.9	47.1	56.0
Total sales *(mbbls/day)*	**78.0**	**75.3**	**72.8**	**74.8**	73.5	76.7	69.1	79.4
Upgrading differential *($/bbl)*	**21.83**	**17.22**	**15.18**	**14.56**	27.89	29.46	26.67	32.31
Canadian Refined Products								
Fuel sales *(millions of litres/day)*	**7.4**	**7.5**	**7.2**	**7.5**	8.0	7.7	7.5	7.4
Refinery throughput[(6)]								
Lloydminster Refinery *(mbbls/day)*	**28.2**	**28.3**	**26.1**	**22.8**	25.3	27.8	26.8	28.7
Prince George Refinery *(mbbls/day)*[(8)]	**3.9**	**11.4**	**3.5**	**10.2**	10.7	11.5	8.8	12.0
U.S. Refining and Marketing								
Refinery throughput[(6)]								
Lima Refinery *(mbbls/day)*	**21.4**	**174.3**	**179.8**	**171.4**	105.9	163.3	171.2	164.4
BP-Husky Toledo Refinery *(mbbls/day)*[(7)]	**70.3**	**66.8**	**57.5**	**58.0**	73.2	70.8	65.5	75.0
Superior Refinery *(mbbls/day)*	**—**	**—**	**—**	**—**	—	—	10.1	37.0

(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%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*
(3) *Operating netback is a non-GAAP measure. Refer to Section 9.3.*
(4) *Includes associated co-products converted to boe.*
(5) *Includes associated co-products converted to mcfge.*
(6) *Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.*
(7) *Reported throughput volumes include Husky's working interest from the BP-Husky Toledo Refinery (50%).*
(8) *Sale of Prince George Refinery closed on November 1, 2019*

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 performance in the Upstream operations were offset by the lower realized upgrading margins and lower earnings in U.S. Refining and Marketing as the Lima Refinery completed a planned turnaround in late 2019, which were offset by insurance recoveries for the Superior Refinery. This resulted in a decrease to the 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:

2019

Q4:

- The Company recognized a pre-tax impairment charge of $2,405 million within the Sunrise Energy Project, Western Canada and Atlantic. The impairment charge was primarily due to sustained declines in forecasted short and long-term crude oil and natural gas prices and management's decision to reduce capital investment in these areas.
- The Company recognized a pre-tax write-down of $339 million related to certain Exploration and Evaluation assets in Atlantic and Western Canada. The write-down was primarily due to changes in management's future development plans resulting from sustained declines in forecasted short and long-term prices for crude oil.
- The Company recognized a pre-tax derecognition charge of $254 million on the carrying value of components replaced as part of the crude oil flexibility project at the Lima Refinery.
- The Company closed the sale of the Prince George Refinery to Tidewater Midstream and Infrastructure.
- The Company recognized a pre-tax impairment charge of $90 million on the Lloyd Ethanol Plant and Minnedosa Ethanol Plant, primarily due to sustained declines in forecasted ethanol margins.
- At the Spruce Lake Central project, construction on the CPF was completed.
- At the Wembley area, in the Montney Formation, six liquids-rich wells were started up.
- At the Liuhua 29-1 field, at Liwan, the remaining four of seven wells were completed.
- At the Lima Refinery a planned turnaround was completed, with final tie-ins made for the crude oil flexibility project.
- The Company recognized $308 million in pre-tax insurance recoveries for rebuild costs, incident costs and business interruption associated with the incident at the Superior Refinery.

Q3:

- At the Dee Valley Thermal Project, first oil was achieved and nameplate capacity was reached.
- At the Spruce Lake North Thermal Project, concrete work was completed.
- At the Spruce Lake East Thermal Project, regulatory approval was received and lease construction was completed.
- At the Karr area, in the Montney Formation, one well was drilled.
- At the Liuhua 29-1 field, at Liwan, three of the seven wells were fully completed.
- At the White Rose field and satellite extension, full production was restored.
- At the Superior Refinery, permits necessary for the rebuild were received and rebuilding work began.
- The Company recognized $138 million in pre-tax insurance recoveries for incident costs and business interruption associated with the incident at the Superior Refinery.

Q2:

- At the Dee Valley Thermal Project, first steam was achieved.
- At the Spruce Lake North Thermal Project, site piling was completed and concrete work progressed.
- At the Spruce Lake East Thermal Project, lease construction started.
- At the Dee Valley 2 and Edam Central Thermal Projects, regulatory approval was received.
- At the Ansell and Kakwa areas, in the liquids-rich Cardium and Spirit River formations, two wells were drilled and four were completed.
- At the Liuhua 29-1 field, three development wells were drilled.
- Two infill wells were completed at the White Rose field and satellite extensions.
- The Company wrote off the Tiger's Eye D-17 exploration well.
- An exploration well drilled on Block 16/25 in 2018, which did not encounter commercial hydrocarbons, was written off.
- The Company recognized $233 million in tax recoveries related to the reduction in the Alberta provincial corporate tax rate.
- The Company recognized $71 million in pre-tax insurance recoveries for incident costs and business interruption associated with the incident at the Superior Refinery.

Q1:

- At the Dee Valley Thermal Project, drilling and fabrication of the Central Processing Facility was completed.
- At the Spruce Lake Central Thermal Project, site piling, concrete work and drilling were all completed. Large vessel and module fabrication progressed.
- At the Spruce Lake North Thermal Project, site preparation was completed, and large vessel and module fabrication progressed.
- At the Spruce Lake East Thermal Project, site preparation was completed, regulatory approval was received, and site clearing commenced.
- At the Ansell and Kakwa areas, in the liquids-rich Cardium and Spirit River Formations, eight wells drilled and six completed.
- At the Sinclair and Wembley areas, in the Montney Formation, four wells were drilled.
- Two infill wells were drilled at the White Rose field and satellite extensions.
- The Company recognized $113 million in pre-tax insurance recoveries for incident costs and business interruption associated with the incident at the Superior Refinery.

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 Lima Refinery 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 work was conducted.
- At the Madura Strait, the BD Project achieved its gross daily sales targets of 100 mmcf/day of conventional 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 commenced with seven wells drilled and four completed.
- Production operations on the *SeaRose* FPSO vessel were suspended for nine days due to a regulatory suspension.

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production[(1)]				Infrastructure and Marketing				Upgrading			
2019 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**1,281**	**1,241**	**1,252**	**1,184**	**608**	**676**	**648**	**410**	**456**	**464**	**457**	**400**
Royalties	**(88)**	**(81)**	**(83)**	**(71)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Marketing and other	**—**	**—**	**—**	**—**	**10**	**35**	**(14)**	**158**	**—**	**—**	**—**	**—**
Revenues, net of royalties	**1,193**	**1,160**	**1,169**	**1,113**	**618**	**711**	**634**	**568**	**456**	**464**	**457**	**400**
Expenses												
Purchases of crude oil and products	**—**	**—**	**—**	**—**	**591**	**658**	**686**	**401**	**311**	**360**	**375**	**257**
Production, operating and transportation expenses	**435**	**399**	**385**	**415**	**9**	**4**	**5**	**3**	**54**	**57**	**54**	**52**
Selling, general and administrative expenses	**71**	**78**	**69**	**79**	**6**	**—**	**2**	**1**	**(3)**	**7**	**3**	**2**
Depletion, depreciation, amortization and impairment	**2,963**	**497**	**430**	**422**	**2**	**4**	**4**	**2**	**29**	**29**	**28**	**29**
Exploration and evaluation expenses	**390**	**41**	**86**	**30**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Loss (gain) on sale of assets	**(1)**	**—**	**—**	**(2)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other – net	**(11)**	**(18)**	**(35)**	**150**	**—**	**—**	**(2)**	**2**	**—**	**—**	**—**	**—**
	3,847	**997**	**935**	**1,094**	**608**	**666**	**695**	**409**	**391**	**453**	**460**	**340**
Earnings (loss) from operating activities	**(2,654)**	**163**	**234**	**19**	**10**	**45**	**(61)**	**159**	**65**	**11**	**(3)**	**60**
Share of equity investment income (loss)	**8**	**15**	**15**	**12**	**(13)**	**4**	**8**	**10**	**—**	**—**	**—**	**—**
Financial items												
Net foreign exchange gains (losses)	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance income	**3**	**—**	**(1)**	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Finance expenses	**(42)**	**(39)**	**(48)**	**(34)**	**(1)**	**(2)**	**—**	**—**	**—**	**(1)**	**—**	**—**
	(39)	**(39)**	**(49)**	**(33)**	**(1)**	**(2)**	**—**	**—**	**—**	**(1)**	**—**	**—**
Earnings (loss) before income tax	**(2,685)**	**139**	**200**	**(2)**	**(4)**	**47**	**(53)**	**169**	**65**	**10**	**(3)**	**60**
Provisions for (recovery of) income taxes												
Current	**8**	**(9)**	**33**	**—**	**—**	**—**	**(2)**	**2**	**22**	**12**	**6**	**23**
Deferred	**(729)**	**42**	**17**	**(4)**	**(1)**	**13**	**(13)**	**44**	**(5)**	**(9)**	**(7)**	**(7)**
	(721)	**33**	**50**	**(4)**	**(1)**	**13**	**(15)**	**46**	**17**	**3**	**(1)**	**16**
Net earnings (loss)	**(1,964)**	**106**	**150**	**2**	**(3)**	**34**	**(38)**	**123**	**48**	**7**	**(2)**	**44**
Capital expenditures[(3)]	**564**	**597**	**566**	**619**	**1**	**—**	**—**	**1**	**30**	**13**	**12**	**4**
Total assets	**17,533**	**19,956**	**19,847**	**20,025**	**1,661**	**1,619**	**1,504**	**1,458**	**1,203**	**1,219**	**1,178**	**1,204**

(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.*

Segmented Financial Information Con't

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
793	871	804	654	2,222	2,644	2,791	2,283	(489)	(537)	(552)	(444)	4,871	5,359	5,400	4,487
—	—	—	—	—	—	—	—	—	—	—	—	(88)	(81)	(83)	(71)
—	—	—	—	—	—	—	—	—	—	—	—	10	35	(14)	158
793	871	804	654	2,222	2,644	2,791	2,283	(489)	(537)	(552)	(444)	4,793	5,313	5,303	4,574
691	706	671	503	2,140	2,319	2,342	1,828	(489)	(537)	(552)	(444)	3,244	3,506	3,522	2,545
57	69	83	69	241	197	216	215	—	(1)	—	(1)	796	725	743	753
13	13	13	14	10	7	9	7	119	44	86	43	216	149	182	146
119	32	33	34	380	117	122	116	27	24	26	27	3,520	703	643	630
—	—	—	—	—	—	—	—	—	—	—	—	390	41	86	30
(2)	(4)	—	—	—	1	—	—	—	—	—	—	(3)	(3)	—	(2)
—	—	—	—	(307)	(163)	(76)	(108)	(4)	(22)	10	—	(322)	(203)	(103)	44
878	816	800	620	2,464	2,478	2,613	2,058	(347)	(492)	(430)	(375)	7,841	4,918	5,073	4,146
(85)	55	4	34	(242)	166	178	225	(142)	(45)	(122)	(69)	(3,048)	395	230	428
—	—	—	—	—	—	—	—	—	—	—	—	(5)	19	23	22
—	—	—	—	—	—	—	—	20	(8)	2	30	20	(8)	2	30
—	—	—	—	—	—	—	—	11	24	17	19	14	24	16	20
(3)	(4)	(4)	(4)	(4)	(5)	(5)	(4)	(29)	(33)	(48)	(41)	(79)	(84)	(105)	(83)
(3)	(4)	(4)	(4)	(4)	(5)	(5)	(4)	2	(17)	(29)	8	(45)	(68)	(87)	(33)
(88)	51	—	30	(246)	161	173	221	(140)	(62)	(151)	(61)	(3,098)	346	166	417
(4)	35	(1)	8	—	10	2	5	6	3	8	8	32	51	46	46
(20)	(21)	1	—	(54)	25	37	44	20	(28)	(285)	(34)	(789)	22	(250)	43
(24)	14	—	8	(54)	35	39	49	26	(25)	(277)	(26)	(757)	73	(204)	89
(64)	37	—	22	(192)	126	134	172	(166)	(37)	126	(35)	(2,341)	273	370	328
19	23	54	23	241	196	202	129	39	39	24	36	894	868	858	812
1,287	1,663	1,656	1,604	8,691	8,799	8,462	8,768	2,747	3,356	3,507	4,315	33,122	36,612	36,154	37,374

Segmented Financial Information

2018 (*$ 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	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.*

Segmented Financial Information Con't

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

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, 2019. 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 26, 2020

Independent Auditor’s 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, 2019 and 2018, the related consolidated statements of income (loss), comprehensive income (loss), changes in 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, 2019 and 2018, 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, 2019, 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 26, 2020 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 3(ab) to the consolidated financial statements, the Company has changed its method of accounting for leases as of January 1, 2019 due to the adoption of International Financial Reporting Standard 16, Leases.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of the recoverable amount of the Northern, Rainbow, Sunrise and White Rose cash generating units

As discussed in note 9 to the consolidated financial statements, the Company recorded an impairment charge of $2,240 million related to the Northern, Rainbow, Sunrise and White Rose cash generating units (collectively the "CGUs"). The Company identified an indicator of impairment at December 31, 2019 for the CGUs and performed an impairment test to estimate the recoverable amount of the CGUs. The estimated recoverable amount of the CGUs involves numerous estimates, including the cash flows associated with the estimated proved and probable oil and gas reserves, and for the White Rose cash generating unit the possible reserves, and the discount rate. The estimation of proved, probable and possible oil and gas reserves involves the expertise of qualified reserves evaluators, who take into consideration assumptions related to forecasted production, forecasted operating, royalty and capital cost assumptions and forecasted oil and gas prices ("reserve assumptions"). The Company engages independent qualified reserves evaluators to audit the estimate of proved and probable oil and gas reserves associated with the CGUs.

We identified the assessment of the recoverable amount of the CGUs as a critical audit matter. Complex auditor judgment was required in evaluating the Company's estimate of the proved and probable oil and gas reserves for the CGUs, and for the White Rose cash generating unit the possible reserves, and the discount rate, which were inputs into the calculation of the recoverable amount of the CGUs. Auditor judgment was also required to evaluate the reserve assumptions used in the estimate of the reserves associated with the CGUs.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the Company's determination of the recoverable amount of the CGUs, including controls related to the development of the discount rate and the estimation of the oil and gas reserves associated with the CGUs. We evaluated the competence, capabilities and objectivity of the independent qualified reserves evaluators engaged by the Company, who audited the estimate of proved and probable oil and gas reserves associated with the CGUs. We evaluated the competence, capabilities and objectivity of the internal qualified reserves evaluators who estimated the possible oil reserves associated with the White Rose cash generating unit. We evaluated the methodology used by the independent qualified reserves evaluators to audit the estimate of proven and probable reserves associated with the CGUs for compliance with regulatory standards. We evaluated the methodology used by the internal qualified reserves evaluators to estimate the possible oil reserves associated with White Rose cash generating unit for compliance with regulatory standards. We compared the 2019 actual production, operating, royalty and capital costs of the Company to those estimates used in the prior year's estimate of proved reserves to assess the Company's ability to accurately forecast. We compared the forecasted commodity prices used in the estimate of proved, probable and possible reserves to those published by other reserve engineering companies. We compared estimates of forecasted production, forecasted operating, royalty and capital cost assumptions used in the estimate of proved, probable and possible reserves to historical results. We involved a valuation professional with specialized skills and knowledge, who assisted in evaluating the Company's discount rate, by comparing it against market data and other external data. The valuations specialist estimated the recoverable amount of the CGUs using the estimate of the cash flows associated with the CGUs' reserves and the discount rate evaluated by the specialist and compared the results to market data and other external pricing data.

Assessment of the recoverable amount of the Lima cash generating unit

As discussed in note 11 to the consolidated financial statements, the goodwill balance as of December 31, 2019 was $656 million, all of which relates to the Company's Lima refinery. The Lima refinery is a cash generating unit ("Lima CGU") and is tested for impairment on an annual basis or when circumstances indicate that the carrying value may be impaired. The estimated recoverable amount of the Lima CGU involves numerous assumptions, including the estimated future revenue net of oil purchases used in the production of gas, diesel and other petroleum products, future capital expenditures and the discount rate.

We identified the assessment of the recoverable amount of the Lima CGU as a critical audit matter. The estimated recoverable amount of the Lima CGU was subject to estimates and judgment in determining the future cash flows associated with the CGU, and therefore resulted in the application of a higher degree of auditor judgment. Complex auditor judgment was required in evaluating estimated future revenue net of oil purchases used in the production of gas, diesel and other petroleum products, future capital expenditures and the discount rate.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls related to the assessment of the recoverable amount of the Lima CGU, including controls related to the development of the estimated future revenue net of oil purchases, future capital expenditures and discount rate assumptions. We performed sensitivity analyses over the estimated future revenue net of oil purchases, future capital expenditures and discount rate assumptions to assess their impact on the Company's determination that the recoverable amount of the Lima CGU exceeded its carrying value. We compared the Company's historical revenue net of oil purchases and capital expenditure forecasts to actual results to assess the Company's ability to accurately forecast. We involved a valuation professional with specialized skills and knowledge, who assisted in evaluating the Company's discount rate, by comparing it against market data and other external data. The valuations professional estimated the recoverable amount of the Lima CGU using the cash flow forecast of the Lima CGU and the discount rate evaluated by the specialist and compared the result to market data and other external pricing data.

Assessment of the impact of estimated oil and gas reserves on depletion expense related to oil and gas properties

As discussed in Note 3(d) to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method. Under such method, capitalized costs are depleted over 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 either the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied as appropriate in the circumstances. As indicated in Note 9, for the year ended December 31, 2019, the Company recorded depletion expense related to oil and gas properties of $1,842 million. The estimation of proved and probable oil and gas reserves, which are used in the calculation of depletion expense, involves the expertise of qualified reserves evaluators, who take into consideration reserve assumptions. The Company engages independent qualified reserves evaluators to audit the Company's proved and probable oil and gas reserves.

We identified the assessment of the impact of estimated proved and probable oil and gas reserves on the calculation of depletion expense as a critical audit matter. Complex auditor judgment was required in evaluating the Company's estimate of proved and probable oil and gas reserves, which was an input to the calculation of depletion expense. Auditor judgment was also required to evaluate the reserve assumptions used to estimate the proved and probable reserves.

The primary procedures we performed to address this critical audit matter included the following. We tested certain internal controls over the calculation of depletion expense, including controls over the estimation of proved and probable oil and gas reserves. We analyzed and assessed the calculation of depletion expense for compliance with regulatory standards. We evaluated the competence, capabilities and objectivity of the independent qualified reserves evaluators engaged by the Company, who audited the proved and probable oil and gas reserves. We evaluated the methodology used by the independent qualified reserves evaluators to audit the estimate of proved and probable reserves for compliance with regulatory standards. We compared the Company's 2019 actual production, operating, royalty and capital costs to those estimates used in the prior year estimate of proved reserves to assess the Company's ability to accurately forecast. We compared the forecasted commodity prices used in the estimate of proved and probable reserves to those published by other reserve engineering companies. We compared estimates of forecasted production, forecasted operating, royalty and capital cost assumptions used in the estimate of proved and probable reserves to historical results.

KPMG LLP

Chartered Professional Accountants

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

Calgary, Canada
February 26, 2020

Consolidated Financial Statements

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2019**	December 31, 2018
Assets		
Current assets		
Cash and cash equivalents *(note 4)*	**1,775**	2,866
Accounts receivable *(notes 5, 25)*	**1,499**	1,355
Income taxes receivable	**30**	112
Inventories *(note 6)*	**1,486**	1,232
Prepaid expenses	**148**	123
	4,938	5,688
Restricted cash *(notes 7, 17)*	**142**	128
Exploration and evaluation assets *(note 8)*	**643**	997
Property, plant and equipment, net *(note 9)*	**23,623**	25,800
Right-of-use assets, net *(note 10)*	**1,202**	—
Goodwill *(note 11)*	**656**	690
Investment in joint ventures *(note 12)*	**1,182**	1,319
Long-term income taxes receivable	**212**	243
Other assets *(note 13)*	**524**	360
Total Assets	**33,122**	35,225
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 15)*	**3,465**	3,159
Short-term debt *(note 16)*	**550**	200
Long-term debt due within one year *(note 16)*	**400**	1,433
Lease liabilities *(note 10)*	**109**	—
Asset retirement obligations *(note 17)*	**112**	202
	4,636	4,994
Long-term debt *(note 16)*	**4,570**	4,114
Other long-term liabilities *(note 18)*	**454**	1,107
Lease liabilities *(note 10)*	**1,353**	—
Asset retirement obligations *(note 17)*	**2,643**	2,222
Deferred tax liabilities *(note 19)*	**2,170**	3,174
Total Liabilities	**15,826**	15,611
Shareholders' equity		
Common shares *(note 20)*	**7,293**	7,293
Preferred shares *(note 20)*	**874**	874
Contributed surplus	**2**	2
Retained earnings	**8,365**	10,273
Accumulated other comprehensive income	**748**	1,160
Non-controlling interest	**14**	12
Total Shareholders' Equity	**17,296**	19,614
Total Liabilities and Shareholders' Equity	**33,122**	35,225

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 (Loss)

(millions of Canadian dollars, except share data)	Years ended December 31, 2019	2018
Gross revenues	**20,117**	21,919
Royalties	**(323)**	(335)
Marketing and other	**189**	668
Revenues, net of royalties	**19,983**	22,252
Expenses		
Purchases of crude oil and products	**12,817**	14,555
Production, operating and transportation expenses *(note 21)*	**3,017**	2,803
Selling, general and administrative expenses *(note 21)*	**693**	654
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**5,496**	2,591
Exploration and evaluation expenses *(note 8)*	**547**	149
Gain on sale of assets *(note 9)*	**(8)**	(4)
Other – net *(note 13)*	**(584)**	(591)
	21,978	20,157
Earnings (loss) from operating activities	**(1,995)**	2,095
Share of equity investment income *(note 12)*	**59**	69
Financial items *(note 22)*		
Net foreign exchange gain	**44**	14
Finance income	**74**	64
Finance expenses	**(351)**	(314)
	(233)	(236)
Earnings (loss) before income taxes	**(2,169)**	1,928
Provisions for (recovery of) income taxes *(note 19)*		
Current	**175**	75
Deferred	**(974)**	396
	(799)	471
Net earnings (loss)	**(1,370)**	1,457
Earnings (loss) per share *(note 20)*		
Basic	**(1.40)**	1.41
Diluted	**(1.41)**	1.40
Weighted average number of common shares outstanding *(note 20)*		
Basic *(millions)*	**1,005.1**	1,005.1
Diluted *(millions)*	**1,005.1**	1,006.1

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

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars)	Years ended December 31, 2019	2018
Net earnings (loss)	**(1,370)**	1,457
Other comprehensive income (loss)		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans *(note 23)*	**—**	46
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedge	**(6)**	(13)
Equity investment – share of other comprehensive loss	**(2)**	(2)
Exchange differences on translation of foreign operations	**(550)**	857
Hedge of net investment *(note 25)*	**146**	(262)
Other comprehensive income (loss)	**(412)**	626
Comprehensive income (loss)	**(1,782)**	2,083

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, 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 19, 23)*	—	—	—	46	—	—	—	46
Derivatives designated as cash flow hedges (net of tax recovery of $5 million) *(notes 19, 25)*	—	—	—	—	—	(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 19)*	—	—	—	—	857	—	—	857
Hedge of net investment (net of tax recovery of $41 million) *(notes 19, 25)*	—	—	—	—	(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 20)*	—	—	—	(402)	—	—	—	(402)
Dividends declared on preferred shares *(note 20)*	—	—	—	(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
Net loss	**—**	**—**	**—**	**(1,370)**	**—**	**—**	**—**	**(1,370)**
Other comprehensive income (loss)								
Remeasurements of pension plans (net of tax expense of $1 million) *(notes 19, 23)*	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Derivatives designated as cash flow hedges (net of tax recovery of $3 million) *(note 19)*	**—**	**—**	**—**	**—**	**—**	**(6)**	**—**	**(6)**
Equity investment – share of other comprehensive loss	**—**	**—**	**—**	**—**	**—**	**(2)**	**—**	**(2)**
Exchange differences on translation of foreign operations (net of tax recovery of $58 million) *(note 19)*	**—**	**—**	**—**	**—**	**(550)**	**—**	**—**	**(550)**
Hedge of net investment (net of tax expense of $30 million) *(notes 19, 25)*	**—**	**—**	**—**	**—**	**146**	**—**	**—**	**146**
Total comprehensive income (loss)	**—**	**—**	**—**	**(1,370)**	**(404)**	**(8)**	**—**	**(1,782)**
Transactions with owners recognized directly in equity:								
Dividends declared on common shares *(note 20)*	**—**	**—**	**—**	**(503)**	**—**	**—**	**—**	**(503)**
Dividends declared on preferred shares *(note 20)*	**—**	**—**	**—**	**(35)**	**—**	**—**	**—**	**(35)**
Non-controlling interest in subsidiary	**—**	**—**	**—**	**—**	**—**	**—**	**2**	**2**
Balance as at December 31, 2019	**7,293**	**874**	**2**	**8,365**	**750**	**(2)**	**14**	**17,296**

[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, 2019	2018
Operating activities		
Net earnings (loss)	**(1,370)**	1,457
Items not affecting cash:		
Accretion *(notes 17, 22)*	**106**	97
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**5,496**	2,591
Inventory write-down to net realizable value *(note 6)*	**15**	60
Exploration and evaluation expenses *(note 8)*	**355**	29
Deferred income taxes *(note 19)*	**(974)**	396
Foreign exchange	**(26)**	(6)
Stock-based compensation *(notes 20, 21)*	**(2)**	44
Gain on sale of assets *(note 9)*	**(8)**	(4)
Unrealized mark to market loss (gain) *(note 25)*	**44**	(150)
Share of equity investment income *(note 12)*	**(59)**	(69)
Gain on insurance recoveries for damage to property *(note 13)*	**(207)**	(253)
Other	**12**	21
Settlement of asset retirement obligations *(note 17)*	**(276)**	(181)
Deferred revenue *(note 18)*	**(42)**	(100)
Distribution from joint ventures *(note 12)*	**187**	72
Change in non-cash working capital *(note 24)*	**(280)**	130
Cash flow – operating activities	**2,971**	4,134
Financing activities		
Long-term debt issuance *(note 16)*	**1,000**	—
Long-term debt repayment *(note 16)*	**(1,389)**	—
Short-term debt issuance, net *(note 16)*	**350**	—
Debt issue costs *(note 16)*	**(9)**	—
Dividends on common shares *(note 20)*	**(503)**	(402)
Dividends on preferred shares *(note 20)*	**(35)**	(35)
Finance lease payments *(note 10)*	**(233)**	—
Other	**(1)**	(8)
Change in non-cash working capital *(note 24)*	**3**	120
Cash flow – financing activities	**(817)**	(325)
Investing activities		
Capital expenditures	**(3,432)**	(3,578)
Capitalized interest *(note 22)*	**(177)**	(108)
Corporate acquisition *(note 9)*	**—**	(15)
Proceeds from asset sales *(note 9)*	**277**	4
Investment in joint ventures *(note 12)*	**(40)**	(40)
Other	**2**	(19)
Change in non-cash working capital *(note 24)*	**173**	235
Cash flow – investing activities	**(3,197)**	(3,521)
Increase (decrease) in cash and cash equivalents	**(1,043)**	288
Effect of exchange rates on cash and cash equivalents	**(48)**	65
Cash and cash equivalents at beginning of year	**2,866**	2,513
Cash and cash equivalents at end of year	**1,775**	2,866
Supplementary cash flow information		
Net interest paid	**(330)**	(285)
Net Income taxes paid	**(41)**	(37)

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, 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 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 in Canada include upgrading heavy crude oil feedstock into synthetic crude oil and diesel ("Upgrading"), refining crude oil, producing ethanol and marketing heavy and synthetic crude oil, refined petroleum products including gasoline, diesel, ethanol-blended fuels, asphalt and ancillary products ("Canadian Refined Products"). It also includes crude oil refining 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.

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing[2]		Total	
Years ended December 31,	**2019**	2018	**2019**	2018	**2019**	2018
Gross revenues	**4,958**	4,330	**2,342**	2,211	**7,300**	6,541
Royalties	**(323)**	(335)	**—**	—	**(323)**	(335)
Marketing and other	**—**	—	**189**	668	**189**	668
Revenues, net of royalties	**4,635**	3,995	**2,531**	2,879	**7,166**	6,874
Expenses						
Purchases of crude oil and products	**—**	—	**2,336**	2,087	**2,336**	2,087
Production, operating and transportation expenses	**1,634**	1,527	**21**	23	**1,655**	1,550
Selling, general and administrative expenses	**297**	296	**9**	5	**306**	301
Depletion, depreciation, amortization and impairment	**4,312**	1,811	**12**	—	**4,324**	1,811
Exploration and evaluation expenses	**547**	149	**—**	—	**547**	149
Loss (gain) on sale of assets	**(3)**	(2)	**—**	—	**(3)**	(2)
Other – net	**86**	(120)	**—**	2	**86**	(118)
	6,873	3,661	**2,378**	2,117	**9,251**	5,778
Earnings (loss) from operating activities	**(2,238)**	334	**153**	762	**(2,085)**	1,096
Share of equity investment income	**50**	51	**9**	18	**59**	69
Financial items						
Net foreign exchange gain	**—**	—	**—**	—	**—**	—
Finance income	**3**	12	**—**	—	**3**	12
Finance expenses	**(163)**	(109)	**(3)**	—	**(166)**	(109)
	(160)	(97)	**(3)**	—	**(163)**	(97)
Earnings (loss) before income taxes	**(2,348)**	288	**159**	780	**(2,189)**	1,068
Provisions for (recovery of) income taxes						
Current	**32**	(484)	**—**	354	**32**	(130)
Deferred	**(674)**	549	**43**	(141)	**(631)**	408
	(642)	65	**43**	213	**(599)**	278
Net earnings (loss)	**(1,706)**	223	**116**	567	**(1,590)**	790
Intersegment revenues	**1,660**	1,155	**—**	—	**1,660**	1,155

(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 $201 million of revenue (2018 - $172 million) and $269 million of associated costs (2018 - $142 million) for construction contracts, inclusive of $193 million of revenue (2018 - $172 million) and $261 million of costs (2018 - $142 million) for contracts in progress with revenue recognized as performance obligations are met.*

(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					
2019	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018
1,777	1,750	3,122	3,412	9,940	11,770	14,839	16,932	(2,022)	(1,554)	20,117	21,919
—	—	—	—	—	—	—	—	—	—	(323)	(335)
—	—	—	—	—	—	—	—	—	—	189	668
1,777	1,750	3,122	3,412	9,940	11,770	14,839	16,932	(2,022)	(1,554)	19,983	22,252
1,303	928	2,571	2,760	8,629	10,334	12,503	14,022	(2,022)	(1,554)	12,817	14,555
217	195	278	265	869	795	1,364	1,255	(2)	(2)	3,017	2,803
9	7	53	47	33	22	95	76	292	277	693	654
115	123	218	115	735	450	1,068	688	104	92	5,496	2,591
—	—	—	—	—	—	—	—	—	—	547	149
—	—	(6)	(2)	1	—	(5)	(2)	—	—	(8)	(4)
—	—	—	(1)	(654)	(464)	(654)	(465)	(16)	(8)	(584)	(591)
1,644	1,253	3,114	3,184	9,613	11,137	14,371	15,574	(1,644)	(1,195)	21,978	20,157
133	497	8	228	327	633	468	1,358	(378)	(359)	(1,995)	2,095
—	—	—	—	—	—	—	—	—	—	59	69
—	—	—	—	—	—	—	—	44	14	44	14
—	—	—	—	—	—	—	—	71	52	74	64
(1)	(1)	(15)	(12)	(18)	(14)	(34)	(27)	(151)	(178)	(351)	(314)
(1)	(1)	(15)	(12)	(18)	(14)	(34)	(27)	(36)	(112)	(233)	(236)
132	496	(7)	216	309	619	434	1,331	(414)	(471)	(2,169)	1,928
63	168	38	100	17	9	118	277	25	(72)	175	75
(28)	(33)	(40)	(42)	52	129	(16)	54	(327)	(66)	(974)	396
35	135	(2)	58	69	138	102	331	(302)	(138)	(799)	471
97	361	(5)	158	240	481	332	1,000	(112)	(333)	(1,370)	1,457
263	290	99	109	—	—	362	399	—	—	2,022	1,554

Segmented Financial Information

($ millions)	Upstream Exploration and Production[1]		Infrastructure and Marketing		Total	
Years ended December 31,	**2019**	2018	**2019**	2018	**2019**	2018
Expenditures on exploration and evaluation assets[2]	**46**	242	**—**	—	**46**	242
Expenditures on property, plant and equipment[2]	**2,300**	2,414	**2**	—	**2,302**	2,414
As at December 31,						
Exploration and evaluation assets	**643**	997	**—**	—	**643**	997
Developing and producing assets at cost	**46,587**	44,196	**—**	—	**46,587**	44,196
Accumulated depletion, depreciation, amortization and impairment	**(31,348)**	(27,379)	**—**	—	**(31,348)**	(27,379)
Other property, plant and equipment at cost	**—**	—	**101**	101	**101**	101
Accumulated depletion, depreciation and amortization	**—**	—	**(51)**	(50)	**(51)**	(50)
Total exploration and evaluation assets and property, plant and equipment, net	**15,882**	17,814	**50**	51	**15,932**	17,865
Total right-of-use assets, net	**520**	—	**90**	—	**610**	—
Total assets	**17,533**	19,175	**1,661**	1,301	**19,194**	20,476

(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	
Years ended December 31,	**2019**	2018	**2019**	2018
Gross revenues[1]	**9,120**	9,000	**9,940**	11,770
Royalties	**(264)**	(269)	**—**	—
Marketing and other	**189**	668	**—**	—
Revenue, net of royalties	**9,045**	9,399	**9,940**	11,770
As at December 31,				
Restricted cash – non-current	**—**	—	**—**	—
Exploration and evaluation assets	**599**	935	**—**	—
Property, plant and equipment, net	**14,630**	16,433	**6,053**	6,336
Right-of-use assets, net	**1,044**	—	**156**	—
Goodwill	**—**	—	**656**	690
Investment in joint ventures	**666**	669	**—**	—
Long-term income tax receivable	**212**	243	**—**	—
Other assets[2]	**47**	58	**458**	276
Total non-current assets	**17,198**	18,338	**7,323**	7,302

(1) *Sales to external customers are based on the location of the seller.*
(2) *Includes insurance proceeds of $435 million (2018 - $253 million), 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					
2019	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**46**	242
59	62	**119**	74	**768**	665	**946**	801	**138**	121	**3,386**	3,336
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**643**	997
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**46,587**	44,196
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(31,348)**	(27,379)
2,721	2,659	**2,360**	2,789	**9,534**	9,746	**14,615**	15,194	**1,377**	1,251	**16,093**	16,546
(1,700)	(1,585)	**(1,449)**	(1,581)	**(3,481)**	(3,410)	**(6,630)**	(6,576)	**(1,028)**	(937)	**(7,709)**	(7,563)
1,021	1,074	**911**	1,208	**6,053**	6,336	**7,985**	8,618	**349**	314	**24,266**	26,797
—	—	**143**	—	**157**	—	**300**	—	**292**	—	**1,202**	—
1,203	1,149	**1,287**	1,431	**8,691**	8,566	**11,181**	11,146	**2,747**	3,603	**33,122**	35,225

Geographical Financial Information Con't

China		Other International		Total	
2019	2018	**2019**	2018	**2019**	2018
1,057	1,149	**—**	—	**20,117**	21,919
(59)	(66)	**—**	—	**(323)**	(335)
—	—	**—**	—	**189**	668
998	1,083	**—**	—	**19,983**	22,252
142	128	**—**	—	**142**	128
39	57	**5**	5	**643**	997
2,938	3,030	**2**	1	**23,623**	25,800
2	—	**—**	—	**1,202**	—
—	—	**—**	—	**656**	690
—	—	**516**	650	**1,182**	1,319
—	—	**—**	—	**212**	243
—	—	**19**	26	**524**	360
3,121	3,215	**542**	682	**28,184**	29,537

Disaggregation of Revenue

	Upstream					
($ millions)	Exploration and Production		Infrastructure and Marketing		Total	
Years ended December 31,	**2019**	2018	**2019**	2018	**2019**	2018
Primary Geographical Markets						
Canada	**3,901**	3,181	**2,342**	2,211	**6,243**	5,392
United States	**—**	—	**—**	—	**—**	—
China	**1,057**	1,149	**—**	—	**1,057**	1,149
Total revenue	**4,958**	4,330	**2,342**	2,211	**7,300**	6,541
Major Product Lines						
Light & medium crude oil	**670**	948	**—**	—	**670**	948
Heavy crude oil	**603**	527	**—**	—	**603**	527
Bitumen	**2,302**	1,367	**—**	—	**2,302**	1,367
Total crude oil	**3,575**	2,842	**—**	—	**3,575**	2,842
NGL	**291**	381	**—**	—	**291**	381
Natural gas	**1,092**	1,107	**—**	—	**1,092**	1,107
Total exploration and production	**4,958**	4,330	**—**	—	**4,958**	4,330
Total infrastructure and marketing	**—**	—	**2,342**	2,211	**2,342**	2,211
Synthetic crude	**—**	—	**—**	—	**—**	—
Gasoline	**—**	—	**—**	—	**—**	—
Diesel & distillates	**—**	—	**—**	—	**—**	—
Asphalt	**—**	—	**—**	—	**—**	—
Other	**—**	—	**—**	—	**—**	—
Total refined products	**—**	—	**—**	—	**—**	—
Total revenue	**4,958**	4,330	**2,342**	2,211	**7,300**	6,541

Disaggregation of Revenue Con't

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2019	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018
1,777	1,750	3,122	3,412	—	—	4,899	5,162	(2,022)	(1,554)	9,120	9,000
—	—	—	—	9,940	11,770	9,940	11,770	—	—	9,940	11,770
—	—	—	—	—	—	—	—	—	—	1,057	1,149
1,777	1,750	3,122	3,412	9,940	11,770	14,839	16,932	(2,022)	(1,554)	20,117	21,919
—	—	—	—	—	—	—	—	—	—	670	948
—	—	—	—	—	—	—	—	—	—	603	527
—	—	—	—	—	—	—	—	—	—	2,302	1,367
—	—	—	—	—	—	—	—	—	—	3,575	2,842
—	—	—	—	—	—	—	—	—	—	291	381
—	—	—	—	—	—	—	—	—	—	1,092	1,107
—	—	—	—	—	—	—	—	—	—	4,958	4,330
—	—	—	—	—	—	—	—	—	—	2,342	2,211
1,505	1,445	—	—	—	—	1,505	1,445	—	—	1,505	1,445
—	—	904	1,070	5,414	6,157	6,318	7,227	—	—	6,318	7,227
260	278	1,152	1,303	3,644	4,297	5,056	5,878	—	—	5,056	5,878
—	—	452	454	136	165	588	619	—	—	588	619
12	27	614	585	746	1,151	1,372	1,763	—	—	1,372	1,763
1,777	1,750	3,122	3,412	9,940	11,770	14,839	16,932	—	—	14,839	16,932
1,777	1,750	3,122	3,412	9,940	11,770	14,839	16,932	(2,022)	(1,554)	20,117	21,919

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 by the Board of Directors on February 26, 2020.

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 12), 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 (loss) 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 (loss). 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 (loss) 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. The useful lives of assets are estimated based upon the period the asset is expected to be available for use by the Company.

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.

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 (loss). Acquisition costs incurred are expensed and included in selling, general and administrative expenses in the consolidated statements of income (loss).

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 (loss) 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 but including right-of-use 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, royalty rates, 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 (loss).

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 (loss). 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 (loss). 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 (loss), 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 (loss) 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 (loss).

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 (loss) 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 (loss) 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 (loss). 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 (loss) 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 (Loss)

Comprehensive income (loss) consists of net earnings (loss) 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 (loss). 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

The Company maintains various defined contribution and defined benefit pension plans for its employees.

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 pension plan 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 (loss) 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. 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 (loss) 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%. The Company acts as the general contractor for HMLP projects for fixed price and cost plus contracts. Revenue from fixed price contracts is recognized as performance obligations are met. Revenue from cost plus contracts are recognized as services are performed. Construction services are billed and paid on a monthly basis, or 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 and diesel 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 (loss). 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 (loss) 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 (loss). 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 (loss) 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 (loss) 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 (loss) 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 (loss) per common share is based on net earnings (loss) 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 (loss) per share is based on net earnings (loss) 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 (loss) 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 (loss). As a result, net earnings (loss) 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 (loss) 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 (loss) 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. 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.

z) Leases

Contractual arrangements, which signify a right to control the use of an identified asset for a period of time are considered leases. Each contractual arrangement is assessed to determine if the Company obtains substantially all the economic benefit from use of the identified asset. Leases for which the Company is a lessee are capitalized at the earlier of commencement of the lease term or when the asset becomes available for use, at the present value of the lease payments applying the implicit interest rate, if readily determined, or the Company's incremental borrowing rate. Adjustments to the lease asset are made if the contractual arrangement includes costs to dismantle the asset or any incentives received. Generally, lease components are considered in the present value calculation, with non-lease components expensed as incurred. Leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. The lease liability is remeasured when there is a change in future lease payments arising from a change in rate, if there is a change to the Company's expected residual value guarantee payable, or if there are changes in the assessment for exercising a purchase, termination or extension option. If this occurs, a corresponding adjustment to the carrying value of the right-of-use asset is completed. If the carrying amount of the right-of-use asset has already been reduced to zero, the adjustment is recognized in profit or loss. The Company applies the recognition exemption for short-term leases 12 months or less in length, and leases for which the underlying asset is of low value. The expenses for these leases are recognized systematically over the lease term in either production, operating and transportation expense, purchases of crude oil and products or selling, general and administrative expenses.

i) Nature of Leasing Activities

Oil and Gas Properties

The Company leases offshore vessels and associated equipment for use in developing reserves on oil and gas properties. These leases vary in length and, in certain cases, expenses incurred are allocated to the carrying value of other assets in property, plant and equipment. Additionally, the Company leases land, buildings and equipment for sustainment of the Company's upstream oil and gas operations.

Processing Transportation and Storage

The Company leases tanks with dedicated storage capacity at terminals or facilities while transporting various oil and gas products. The Company also records leases for any pipelines where the Company has a right to substantially all the economic benefits. The terms of these leases vary depending on capacity constraints by third parties and negotiations of take-or-pay arrangements. The Company also employs rail transportation, where the Company leases dedicated rail cars.

Upgrading

The Company does not have any significant leasing arrangements in the upgrading asset class.

Refining

The Company leases supply facilities and pipelines for products used in the refining process when the Company has the right to substantially all the capacity of the asset. The Company also uses rail transportation, where it enters into arrangements for dedicated rail cars.

Retail and Other

The Company leases land and buildings for its office space and retail marketing locations. The leases of office space and marketing locations typically run for approximately 10-20 years with the option to renew for additional periods. When extension options are reasonably certain to be exercised, they are included in the non-cancellable lease term at lease commencement. If there is a significant change in circumstances, extension options are reassessed. Terms and conditions are often renegotiated upon renewals to allow for operational flexibility. The Company leases dedicated tanks or facilities for storage of refined products.

aa) Recent Accounting Standards

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

ab) Change in Accounting Policy

i) Leases

In January 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which replaces the existing IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease is a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the balance sheet while operating leases were recognized in the Consolidated Statements of Income (Loss) when the expense was incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for most lease contracts. The recognition of the present value of the lease payments for certain contracts previously classified as operating leases resulted in increases to assets, liabilities, depletion, depreciation and amortization and finance expense, and a decrease to production, operating and transportation expense, purchases of crude oil and products and selling, general and administrative expenses.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Accordingly, comparative information in the Company's financial statements are not restated.

On adoption, lease liabilities were measured at the present value of the remaining lease payments discounted using the Company's incremental borrowing rate on January 1, 2019. Right-of-use assets were measured at an amount equal to the lease liability. For leases previously classified as operating leases, the Company applied the exemption not to recognize right-of-use assets and liabilities for leases with a lease term of less than 12 months, excluded initial direct costs from measuring the right-of-use asset at the date of initial application and applied a single discount rate to a portfolio of leases with similar characteristics. For leases that were previously classified as finance leases under IAS 17, the carrying amount of the lease asset and lease liability remain unchanged upon transition and were determined at the carrying amount immediately before adoption date. Additionally, instead of an impairment review, the Company adjusted the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application.

No adjustments were required upon transition to IFRS 16 for leases where the Company is a lessor. Under IFRS 16, the Company is required to assess the classification of a sub-lease with reference to the right-of-use asset, not the underlying asset. On transition, the Company reassessed the classification of any sub-lease contracts previously assessed under IAS 17. No changes to sublease classification or associated accounting treatment was required.

Financial Statement Impact

The recognition of the present value of lease payments resulted in an additional $1.3 billion of right-of-use assets and associated lease liabilities. The Company has recognized lease liabilities in relation to lease arrangements previously disclosed as operating lease commitments under IAS 17 that meet the criteria of a lease under IFRS 16. Upon recognition in the consolidated statement of financial position, the Company's weighted average incremental borrowing rate used in measuring lease liabilities was 3.58%.

Note 4 Cash and Cash Equivalents

Cash and cash equivalents at December 31, 2019 included $327 million of cash (December 31, 2018 – $187 million) and $1,448 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2018 – $2,679 million).

Note 5 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2019**	December 31, 2018
Trade receivables	**1,327**	1,146
Provision for expected credit losses	**(34)**	(39)
Derivatives due within one year	**38**	43
Other[1]	**168**	205
End of year	**1,499**	1,355

[1] *Includes insurance proceeds of $114 million (2018 – $143 million), related to the Superior Refinery incident.*

Note 6 Inventories

Inventories

($ millions)	**December 31, 2019**	December 31, 2018
Crude oil, natural gas and NGL	**627**	445
Refined petroleum products	**553**	435
Trading inventories measured at fair value less costs to sell	**155**	200
Materials, supplies and other	**151**	152
End of year	**1,486**	1,232

Impairment of inventory to net realizable value for the year ended December 31, 2019 was $15 million (December 31, 2018 – $60 million), 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.

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, 2019, the Company had deposited funds of $142 million which have been classified as non-current (2018 – $128 million).

Note 8 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	**2019**	2018
Beginning of year	**997**	838
Additions	**46**	287
Disposals	**—**	(23)
Transfers to property, plant and equipment *(note 9)*	**(44)**	(79)
Expensed exploration expenditures previously capitalized	**(355)**	(29)
Exchange adjustments	**(1)**	3
End of year	**643**	997

During 2019, $331 million of the $355 million in total expensed exploration expenditures previously capitalized was primarily related to a write-down related to certain crude oil assets in the Atlantic and Western Canada. The write-down was primarily due to changes in management's future development plans resulting from sustained declines in forecasted short and long-term crude oil prices.

The following exploration and evaluation expenses for the years ended December 31, 2019 and 2018 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)	**2019**	2018
Seismic, geological and geophysical	**131**	102
Expensed drilling	**409**	41
Expensed land	**7**	6
	547	149

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, 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 17)*	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
Transfers to right-of-use assets[(1)] *(note 10)*	**(336)**	**—**	**—**	**(180)**	**—**	**(516)**
Additions[(2)]	**2,340**	**2**	**58**	**899**	**160**	**3,459**
Acquisitions	**10**	**—**	**—**	**—**	**—**	**10**
Transfers from exploration and evaluation *(note 8)*	**44**	**—**	**—**	**—**	**—**	**44**
Transfers from right-of-use assets[(3)] *(note 10)*	**101**	**—**	**—**	**—**	**—**	**101**
Intersegment transfers	**2**	**—**	**—**	**27**	**(29)**	**—**
Changes in asset retirement obligations *(note 17)*	**469**	**1**	**5**	**19**	**23**	**517**
Disposals and derecognition	**(16)**	**(2)**	**(1)**	**(943)**	**(2)**	**(964)**
Exchange adjustments	**(223)**	**(1)**	**—**	**(496)**	**(2)**	**(722)**
December 31, 2019	**46,587**	**101**	**2,721**	**10,017**	**3,245**	**62,671**
Accumulated depletion, depreciation, amortization and impairment						
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)
Transfers to right-of-use assets[(1)] *(note 10)*	**12**	**—**	**—**	**40**	**—**	**52**
Depletion, depreciation, amortization and impairment	**(4,082)**	**(2)**	**(115)**	**(736)**	**(239)**	**(5,174)**
Intersegment transfers	**—**	**—**	**—**	**(17)**	**17**	**—**
Disposals and derecognition	**8**	**—**	**—**	**724**	**2**	**734**
Exchange adjustments	**93**	**1**	**—**	**187**	**1**	**282**
December 31, 2019	**(31,348)**	**(51)**	**(1,700)**	**(3,735)**	**(2,214)**	**(39,048)**
Net book value						
December 31, 2018	16,817	51	1,074	6,758	1,100	25,800
December 31, 2019	**15,239**	**50**	**1,021**	**6,282**	**1,031**	**23,623**

(1) *Transfer to right-of-use assets due to the adoption of IFRS 16 on January 1, 2019.*
(2) *Includes $5 million of interest expense on lease liabilities allocated to the carrying amount of assets in Oil and Gas Properties.*
(3) *Includes capitalized depreciation from right-of-use assets.*

Costs of property, plant and equipment, including major development projects, not subject to depletion, depreciation and amortization as at December 31, 2019 were $6.8 billion (December 31, 2018 – $5.2 billion) including undeveloped land assets of $127 million as at December 31, 2019 (December 31, 2018 – $117 million).

Included in depletion, depreciation, amortization and impairment for the year ended December 31, 2019 is a pre-tax impairment expense of $2,240 million (December 31, 2018 – $nil) on assets on CGUs located at Sunrise, Western Canada and White Rose in the Exploration and Production segment. The impairment charge, reflected in the fourth quarter of 2019 and attributed to the CGUs noted above, was a result of sustained declines in forecasted short and long-term crude oil and natural gas prices and management's decision to reduce capital investment in those CGUs. The recoverable amount of the impaired CGUs was estimated based on fair value less costs to sell methodology using estimated after-tax discounted cash flows on proved plus probable reserves for Sunrise and Western Canada CGUs, and proved plus probable and possible reserves for the White Rose CGU (Level 3). The Company used an after-tax discount rate of 10% (Level 3).

The following table summarizes impairment for each Upstream CGU:

CGU *($ millions)*	Impairment recorded
Northern	**421**
Rainbow	**241**
Western Canada CGUs total	**662**
White Rose CGU	**871**
Sunrise CGU	**707**
Upstream CGUs total	**2,240**

The recoverable amount of the Upstream CGUs was $5.6 billion as at December 31, 2019. The recoverable amount is sensitive to commodity price, discount rate, production volumes, royalties, operating costs and future capital expenditures. Commodity prices are based on market indicators at the end of the period. Management's long-term assumptions are benchmarked against forward price curve and pricing forecasts prepared by external firms.

The table below summarizes the forecasted prices used in determining the recoverable amounts:

	WTI ($US/bbl)	Brent ($US/bbl)	Edmonton Light ($CDN/bbl)	AECO ($CDN/mcf)	Foreign Exchange ($US/$CDN)
2020	61.00	66.00	72.37	2.00	0.76
2021	64.00	68.00	76.62	2.25	0.77
2022	66.00	70.00	78.85	2.50	0.78
2023	68.00	72.00	80.38	2.75	0.79
2024	70.00	74.00	82.91	2.80	0.79
2025	71.40	75.48	84.57	2.86	0.79
2026(1)	72.83	76.99	86.26	2.91	0.79

(1) *Prices are escalated at 2% thereafter.*

The discount rate for FVLCS represents the rate a market participant would apply to the cash flows in a market transaction. The discount rate is derived from the Company's post-tax weighted average cost of capital with appropriate adjustments made to reflect the risks specific to the CGUs. Production volumes, operating costs, royalties and future capital expenditures are based on management's best estimates included in the long range plan approved by the Board of Directors.

A change in the discount rate or forward price over the life of the reserves will result in the following impact on the Upstream CGUs:

	Discount Rate		Commodity Price	
($ millions)	1% Increase in Discount Rate	1% Decrease in Discount Rate	5% Increase in Forward Price	5% Decrease in Forward Price
Impairment of PP&E – Increase (Decrease)	528	(605)	(910)	904

Also included in depletion, depreciation, amortization and impairment for the year ended December 31, 2019 is a pre-tax impairment expense of$90 million (December 31, 2018 – $nil) at the Lloyd and Minnedosa Ethanol plants within the Canadian Refined Products segment. The impairment charge, reflected in the fourth quarter of 2019 and attributed to the CGUs noted above, was a result of sustained declines in forecasted ethanol margins. The recoverable amount of the impaired CGUs was estimated using after-tax discounted cash flows (Level 3). The Company used comparative market multipliers to corroborate discounted cash flow results.

The recoverable amount of these Downstream CGUs was $106 million as at December 31, 2019.

The following table summarizes impairment for each CGU in downstream:

CGU *($ millions)*	Impairment recorded
Minnedosa Ethanol Plant	78
Lloydminster Ethanol Plant	12
Downstream CGUs total	**90**

Depletion, depreciation, amortization and impairment for the year ended December 31, 2019 also included a $254 million pre-tax derecognition of the carrying value of components replaced as part of the crude oil flexibility project at the Lima Refinery in the U.S Refining and Marketing segment (December 31, 2018 – a pre-tax impairment expense of $56 million related to the Superior Refinery in the U.S. Refining and Marketing segment).

Assets Dispositions

On November 1, 2019, the Company completed the sale of its Prince George Refinery to Tidewater Midstream and Infrastructure Ltd. for$215 million in cash plus an inventory closing adjustment of approximately $53.5 million. Upon completion of the sale of the Prince George Refinery, the Company entered into a supply agreement to purchase substantially all of the refinery's production, resulting in a $55 million sale leaseback.The transaction resulted in a pre-tax gain of $2 million and an after-tax gain of $1 million. The assets and related liabilities were recorded in the Canadian Refined Products segment.

Note 10 Right-of-use Assets and Lease Liabilities

Right-of-use Assets

($ millions)	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
January 1, 2019						
Transfers from property, plant and equipment, net *(note 9)*	324	—	—	140	—	464
Initial recognition	721	100	—	70	412	1,303
	1,045	100	—	210	412	1,767
Additions	1	—	—	80	5	86
Transfers to property, plant and equipment *(note 9)*	(101)	—	—	—	—	(101)
Disposals and derecognition	(11)	—	—	(31)	2	(40)
Revaluation	(194)	1	—	(1)	8	(186)
Depreciation and impairment	(222)	(11)	—	(50)	(39)	(322)
Other	2	—	—	(4)	—	(2)
December 31, 2019	**520**	**90**	**—**	**204**	**388**	**1,202**

During 2019, $165 million of right-of-use assets were expensed related to impairment recorded within the Exploration and Production segment. Refer to Note 9.

Lease Liabilities

Balance Sheets

($ millions)	December 31, 2019
Current lease liabilities[1]	**109**
Non-current lease liabilities[1]	**1,353**

[1] Includes $489 million previously recorded in accrued liabilities and other long-term liabilities as at December 31, 2018.

Reconciliation to Operating Lease Commitments

($ millions)	
Operating agreements included in commitments at December 31, 2018[1]	2,343
Expenses relating to short-term leases	**(9)**
Discounting	**(986)**
Additional lease liability recognized due to adoption of IFRS 16 on January 1, 2019	**1,348**

[1] Includes commitments from operating agreements, firm transportation agreements, and unconditional purchase obligations.

Maturity Analysis	Within 1 year		After 1 year but no more than 5 years		More than 5 years		Total	
($ millions)	**2019**	2018[1]	**2019**	2018[1]	**2019**	2018[1]	**2019**	2018[1]
Future lease payments	**205**	69	**653**	242	**2,174**	1,014	**3,032**	1,325
Interest	**96**	48	**352**	175	**1,122**	613	**1,570**	836
Present value of lease payments	**109**	21	**301**	67	**1,052**	401	**1,462**	489

[1] Amounts for 2018 were future payments under finance leases obligations, prior to the adoption of IFRS 16.

Results of Operations

($ millions)	December 31, 2019
Interest expense on lease liabilities[1] *(note 22)*	**106**
Expenses relating to short-term leases	**18**

[1] Includes $5 million of interest allocated to the carrying amount of assets in Oil and Gas Properties for the year ended December 31, 2019.

Cash Flow Summary

($ millions)	December 31, 2019
Total cash flow used for leases	**339**

The Company's major office building leases contain extension options that are exercisable by the Company up to one year prior to the end of the non-cancellable lease term. As at December 31, 2019, $380 million of lease liabilities related to office buildings have been recognized. Discounted potential lease payments associated with extension options not included in lease liabilities amount to $238 million.

During 2019, the Company revalued the Henry Goodrich right-of-use asset due to a shortened contract term, resulting in a reduction of the right-of-use asset and lease liability by $185 million.

Note 11 Goodwill

Goodwill

($ millions)	December 31, 2019	December 31, 2018
Beginning of year	690	633
Exchange adjustments	(34)	57
End of year	656	690

As at December 31, 2019, 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 FVLCS methodology based on cash flows expected over a 50-year period and an after-tax discount rate of 9% (2018 – 8%).

Management used the FVLCS calculation for the Lima Refinery CGU, which is sensitive to changes in discount rate, forecasted crack spreads and future capital expenditures. 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.

After-tax 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% and 2%, 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% (2018 – 2%). As at December 31, 2019, 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 12 Joint Arrangements

Joint Operations

BP-Husky Refining LLC
The Company holds a 50% ownership interest in BP-Husky Refining LLC, which owns and operates the BP-Husky Toledo Refinery in Ohio.

Sunrise Oil Sands Partnership
The Company holds a 50% 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 holds 40% 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 (loss) in the 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)	2019	2018
Revenues	424	441
Expenses	(267)	(273)
Net earnings	157	168
Share of equity investment	40%	40%
Proportionate share of equity investment	50	51

Balance Sheets

($ millions, except share of equity investment)	December 31, 2019	December 31, 2018
Current assets[(1)]	**208**	373
Non-current assets	**1,840**	2,072
Current liabilities	**(70)**	(123)
Non-current liabilities[(2)]	**(1,427)**	(1,917)
Net assets	**551**	405
Share of net assets	**40%**	40%
Carrying amount in balance sheet	**516**	650

(1) *Includes cash and cash equivalents of $42 million (2018 – $203 million).*
(2) *Includes deferred revenue of nil (2018 – $2 million) 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% 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

The Company holds a 35% interest in HMLP, which owns midstream assets in Alberta and Saskatchewan. The assets are held by HMLP, of which Husky owns 35%, Power Assets Holdings Ltd. ("PAH") owns 48.75% and CK Infrastructure Holdings Ltd. ("CKI") owns 16.25%. Results of the joint venture are included in the consolidated statements of income (loss) 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)	2019	2018
Revenues	**316**	296
Expenses	**(228)**	(177)
Net earnings	**88**	119
Share of equity investment	**35%**	35%
Proportionate share of equity investment	**9**	18

Balance Sheet

($ millions, except share of net assets)	December 31, 2019	December 31, 2018
Current assets[(1)]	**171**	115
Non-current assets	**3,031**	2,849
Current liabilities	**(163)**	(153)
Non-current liabilities	**(1,059)**	(825)
Net assets	**1,980**	1,986
Share of net assets	**35%**	35%
Carrying amount in balance sheet	**666**	669

(1) *Current assets include cash and cash equivalents of $86 million (2018 – $16 million).*

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

Note 13 Other Assets

Other Assets

($ millions)	December 31, 2019	December 31, 2018
Long-term receivables[1]	**489**	319
Precious metals	**22**	23
Other	**13**	18
End of year	**524**	360

[1] *Includes insurance proceeds of $435 million (2018 – $253 million), related to the Superior Refinery incident.*

For the year ended December 31, 2019, the Company accrued pre-tax recoveries for rebuild costs, incident costs and business interruption associated with the Superior Refinery incident of $630 million (December 31, 2018 – $468 million), which is included in other-net in the consolidated statements of income (loss).

Note 14 Bank Operating Loans

At December 31, 2019, the Company had unsecured short-term borrowing lines of credit with banks totalling $900 million[1] (December 31, 2018 – $900 million) and letters of credit under these lines of credit totalling $436 million (December 31, 2018 – $439 million). As at December 31, 2019, bank operating loans were nil (December 31, 2018 – 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, 2018 – $10 million) available for general purposes. The Company's proportionate share of the credit facility is $5 million (December 31, 2018 – $5 million). As at December 31, 2019, there was no balance outstanding under this credit facility (December 31, 2018 – no balance).

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

Note 15 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	December 31, 2019	December 31, 2018
Trade payables	**1,178**	1,121
Accrued liabilities	**1,954**	1,712
Dividend payable *(note 20)*	**126**	126
Stock-based compensation	**19**	32
Derivatives due within one year	**21**	39
Other	**167**	129
End of year	**3,465**	3,159

Note 16 Debt and Credit Facilities

Short-term Debt

($ millions)	**December 31, 2019**	December 31, 2018
Commercial paper[(1)]	**550**	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, 2019 was 1.98% per annum (December 31, 2018 – 2.20%).*

Long-term Debt		Canadian $ Amount		U.S. $ Denominated	
($ millions)	Maturity	**December 31, 2019**	December 31, 2018	**December 31, 2019**	December 31, 2018
Long-term debt					
5.00% notes[(5)]	2020	**—**	400	**—**	—
3.95% notes[(1)(4)]	2022	**648**	682	**500**	500
4.00% notes[(1)(4)]	2024	**973**	1,023	**750**	750
3.55% notes[(5)]	2025	**750**	750	**—**	—
3.60% notes[(5)]	2027	**750**	750	**—**	—
4.40% notes[(1)(4)]	2029	**973**	—	**750**	—
6.80% notes[(1)(4)]	2037	**501**	528	**387**	387
Debt issue costs[(2)]		**(25)**	(19)	**—**	—
Long-term debt		**4,570**	4,114	**2,387**	1,637
Long-term debt due within one year					
6.15% notes[(1)(3)]	2019	**—**	410	**—**	300
7.25% notes[(1)(4)]	2019	**—**	1,023	**—**	750
5.00% notes[(5)]	2020	**400**	—	**—**	—
Long-term debt due within one year		**400**	1,433	**—**	1,050

(1) *The 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 25 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%, the 4.40% 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

The Company has two $2.0 billion revolving unsecured syndicated credit facilities that mature on June 19, 2022 and March 9, 2024.

As at December 31, 2019 the covenants under the Company's syndicated credit facilities are debt to capital covenants, 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. These covenants are used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2019, and assessed the risk of non-compliance to be low. As at December 31, 2019, the Company had no direct borrowings under its $2.0 billion facility expiring June 19, 2022 (December 31, 2018 – no direct borrowings) and no direct borrowings under its $2.0 billion facility expiring March 9, 2024 (December 31, 2018 – no direct borrowings).

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.

Notes

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. During the three months ended March 31, 2019, the Company discontinued these cash flow hedges and these interest rate swaps were settled and derecognized during the year.

On March 15, 2019, the Company issued US$750 million in senior unsecured notes. The notes bear an annual interest rate of 4.40% and are due on April 15, 2029. The Company raised the net proceeds of the offering for general corporate purposes, which included the repayment of certain outstanding debt securities that matured in 2019.

On May 1, 2019, the Company filed a universal short form base shelf prospectus (the "2019 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 June 1, 2021.

On June 17, 2019, the Company repaid the maturing 6.15% notes. The amount paid to note holders was $402 million.

On December 16, 2019, the Company repaid the maturing 7.25% notes. The amount paid to note holders was $987 million.

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

Base Shelf Prospectus

At December 31, 2019, the Company had unused capacity of $3.0 billion under its 2019 Canadian Shelf Prospectus and US$2.25 billion under its 2018 U.S. Shelf Prospectus and related U.S. registration statement.

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	Lease liabilities due within one year	Lease liabilities
December 31, 2018	200	1,433	4,114	1,107	—	—
Changes from financing cash flows						
Long-term debt issuance	**—**	**—**	**1,000**	**—**	**—**	**—**
Long-term debt repayment	**—**	**(1,389)**	**—**	**—**	**—**	**—**
Short-term debt issuance, net	**350**	**—**	**—**	**—**	**—**	**—**
Debt issue costs	**—**	**—**	**(9)**	**—**	**—**	**—**
Finance lease payments	**—**	**—**	**—**	**—**	**(233)**	**—**
Total change from financing cash flows	**350**	**(1,389)**	**991**	**—**	**(233)**	**—**
Other changes – liability-related						
Initial recognition of lease liabilities *(note 10)*	**—**	**—**	**—**	**(467)**	**22**	**1,815**
Foreign exchange	**—**	**—**	**(8)**	**(12)**	**—**	**(3)**
Fair value changes	**—**	**—**	**—**	**(4)**	**—**	**(240)**
Net additions of lease liabilities	**—**	**—**	**—**	**—**	**—**	**89**
Reclassification	**—**	**400**	**(400)**	**(114)**	**319**	**(319)**
Deferred revenue	**—**	**—**	**—**	**(42)**	**—**	**—**
Amortization of debt issuance costs	**—**	**—**	**5**	**—**	**—**	**—**
Foreign exchange recognized in OCI	**—**	**(44)**	**(132)**	**—**	**—**	**—**
Other	**—**	**—**	**—**	**(14)**	**1**	**11**
Total other changes – liability related	**—**	**356**	**(535)**	**(653)**	**342**	**1,353**
December 31, 2019	**550**	**400**	**4,570**	**454**	**109**	**1,353**

Note 17 Asset Retirement Obligations

At December 31, 2019, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $10.0 billion (December 31, 2018 – $9.2 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, 2018 – 45 years) into the future. This amount has been discounted using credit-adjusted risk-free rates of 3.9% to 4.4% (December 31, 2018 – 3.8% to 5.0%) and an inflation rate of 2% (December 31, 2018 – 2%). Obligations related to future environmental remediation and cleanup of oil and gas assets are included in the estimated ARO.

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, 2019 and 2018 is set out below:

Asset Retirement Obligations

($ millions)	**2019**	2018
Beginning of year	**2,424**	2,526
Additions	**76**	40
Liabilities settled	**(276)**	(270)
Liabilities disposed	**(6)**	(11)
Change in discount rate	**285**	(68)
Change in estimates	**156**	93
Exchange adjustment	**(10)**	17
Accretion *(note 22)*	**106**	97
End of year	**2,755**	2,424
Expected to be incurred within 1 year	**112**	202
Expected to be incurred beyond 1 year	**2,643**	2,222

At December 31, 2019, the Company had deposited funds of $142 million into the restricted accounts for funding of future asset retirement obligations in offshore China (December 31, 2018 – $128 million). These amounts have been classified as non-current and included in restricted cash.

Note 18 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	**December 31, 2019**	December 31, 2018
Employee future benefits *(note 23)*	**214**	205
Finance lease obligations *(note 10)*	**—**	467
Stock-based compensation	**19**	42
Deferred revenue	**152**	205
Other	**69**	188
End of year	**454**	1,107

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, 2019**	December 31, 2018
Beginning of year	**205**	284
Revenue recognized	**(42)**	(100)
Exchange adjustment	**(11)**	21
End of year	**152**	205

Note 19 Income Taxes

The major components of income tax expense (recovery) for the years ended December 31, 2019 and 2018 were as follows:

Income Tax Expense (Recovery)

($ millions)	2019	2018
Current income tax		
Current income tax charge	**174**	86
Adjustments to current income tax estimates	**1**	(11)
	175	75
Deferred income tax		
Relating to origination and reversal of temporary differences	**(723)**	378
Adjustments to deferred income tax estimates	**(251)**	18
	(974)	396

Deferred Tax Items in OCI

($ millions)	2019	2018
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**(3)**	(5)
Remeasurement of pension plans	**1**	17
Exchange differences on translation of foreign operations	**(58)**	87
Hedge of net investment	**30**	(41)
	(30)	58

The provision for income taxes in the consolidated statements of income (loss) reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31, 2019 and 2018 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	2019	2018
Earnings (loss) before income taxes		
Canada	**(3,170)**	734
United States	**337**	493
Other foreign jurisdictions	**664**	701
	(2,169)	1,928
Statutory Canadian income tax rate	**26.8%**	27.2%
Expected income tax	**(582)**	525
Effect on income tax resulting from:		
Foreign jurisdictions	**61**	(36)
Non-taxable items	**(25)**	(13)
Adjustments with respect to previous year	**(250)**	7
Revaluation of foreign tax pools	**(4)**	(4)
Other – net	**1**	(8)
Income tax expense (recovery)	**(799)**	471

The statutory tax rate is 26.8% in 2019 (2018 – 27.2%). The 2019 and 2018 tax rates were changed due to a 0.5% decrease to the Alberta Provincial corporate tax rate that was substantively enacted in the second quarter of 2019 resulting in a deferred tax recovery of $233 million.

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

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2019	Recognized in Earnings	Recognized in OCI	Other	**December 31, 2019**
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(4,089)	**967**	**69**	**—**	**(3,053)**
Foreign exchange gains taxable on realization	(174)	**51**	**(27)**	**—**	**(150)**
Debt issue costs	(4)	**(1)**	**—**	**—**	**(5)**
Other temporary differences	(28)	**(124)**	**—**	**—**	**(152)**
Deferred tax assets					
Pension plans	8	**9**	**(1)**	**—**	**16**
Asset retirement obligations	654	**16**	**(4)**	**—**	**666**
Loss carry-forwards	468	**56**	**(7)**	**—**	**517**
Financial assets at fair value	(9)	**—**	**—**	**—**	**(9)**
	(3,174)	**974**	**30**	**—**	**(2,170)**

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)

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2019, the Company had nil deferred tax liabilities in respect to these investments (December 31, 2018 – nil).

At December 31, 2019, the Company had $2,105 million (December 31, 2018 – $1,806 million) of tax losses that will expire between 2030 and 2039. 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 20 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, 2017	1,005,120,012	7,293
Options exercised[1]	1,726	—
December 31, 2018	1,005,121,738	7,293
December 31, 2019	**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.

Common Share Dividends ($ millions)	2019		2018	
	Declared	Paid	Declared	Paid
	503	**503**	402	276

At December 31, 2019, Common Share dividends payable were $126 million (December 31, 2018 – $126 million).

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, 2017	36,000,000	874
December 31, 2018	36,000,000	874
December 31, 2019	**36,000,000**	**874**

Cumulative Redeemable Preferred Shares Dividends ($ millions)	2019		2018	
	Declared	Paid	Declared	Paid
Series 1 Preferred Shares	**6**	**6**	6	8
Series 2 Preferred Shares	**1**	**1**	1	1
Series 3 Preferred Shares	**12**	**12**	12	14
Series 5 Preferred Shares	**9**	**9**	9	11
Series 7 Preferred Shares	**7**	**7**	7	9
	35	**35**	35	43

At December 31, 2019, Preferred Share dividends payable were nil (December 31, 2018 – nil).

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% 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%. 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, 2019 but excluding December 31, 2019, was 3.368% based on the sum of the Government of Canada 90 day Treasury bill rate on August 20, 2019 plus 1.73%. 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 4.689% annually for the initial period ending December 31, 2024 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%. 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, 2024 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%.

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% 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%. 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%.

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% 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%. 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%.

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 they wish to surrender their 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, 2019 was $4 million (December 31, 2018 – $11 million) representing the estimated fair value of options outstanding. The total recovery recognized in selling, general and administrative expenses in the consolidated statements of income (loss) for the Option Plan for the year ended December 31, 2019 was $6 million (December 31, 2018 – recovery of $3 million). At December 31, 2019, the intrinsic value of stock options exercisable for cash was less than one million (December 31, 2018 – nil).

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

Outstanding and Exercisable Options	2019		2018	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**19,967**	**21.48**	22,645	23.96
Granted[(1)]	**4,241**	**14.31**	5,610	17.21
Exercised for common shares	**—**	**—**	(2)	15.67
Surrendered for cash	**(4)**	**15.67**	(1,772)	15.82
Expired or forfeited	**(5,706)**	**28.27**	(6,514)	27.69
Outstanding, end of year	**18,498**	**17.75**	19,967	21.48
Exercisable, end of year	**10,596**	**19.27**	10,461	25.87

(1) *Options granted during the year ended December 31, 2019 were attributed a fair value of $2.34 per option (December 31, 2018 – $2.90) at grant date.*

Outstanding and Exercisable Options	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$9.28 - $16.31	10,341	15.34	2.65	5,350	15.86
$16.32 - $25.41	8,157	20.80	1.86	5,246	22.75
December 31, 2019	**18,498**	**17.75**	**2.30**	**10,596**	**19.27**

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, 2019	December 31, 2018
	Tandem Options	Tandem Options
Dividend per option	**0.42**	0.56
Range of expected volatilities used *(percent)*	**27.5 - 35.5**	16.8 - 44.4
Range of risk-free interest rates used *(percent)*	**1.66 - 1.74**	1.6 - 1.9
Expected life of share options from vesting date *(years)*	**1.97**	1.95
Expected forfeiture rate *(percent)*	**8.8**	8.9
Weighted average exercise price	**18.19**	22.46
Weighted average fair value	**0.25**	0.65

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

The Company has a 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 (loss) 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 (loss) 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, 2019, the carrying amount of the liability relating to PSUs was $34 million (December 31, 2018 – $63 million). The total expense recognized in selling, general and administrative expenses in the consolidated statements of income (loss) for the PSUs for the year ended December 31, 2019 was $4 million (2018 – $47 million). The Company paid out $34 million (2018 – $24 million) for performance share units which vested in the year. The weighted average contractual life of the PSUs at December 31, 2019 was two years (December 31, 2018 – two years).

The number of PSUs outstanding was as follows:

Performance Share Units	2019	2018
Beginning of year	**11,606,644**	8,361,918
Granted	**7,673,960**	6,108,430
Exercised	**(2,429,816)**	(1,354,316)
Forfeited	**(2,532,146)**	(1,509,388)
Outstanding, end of year	**14,318,642**	11,606,644
Vested, end of year	**3,264,840**	4,487,585

Earnings (loss) per Share

Earnings (loss) per Share *($ millions)*	2019	2018
Net earnings (loss)	**(1,370)**	1,457
Effect of dividends declared on preferred shares in the year	**(35)**	(35)
Net earnings (loss) – basic	**(1,405)**	1,422
Dilutive effect of accounting for stock options(1)	**(15)**	(13)
Net earnings (loss) – diluted	**(1,420)**	1,409
(millions)		
Weighted average common shares outstanding – basic	**1,005.1**	1,005.1
Effect of stock dividends declared in the year	**—**	1.0
Weighted average common shares outstanding – diluted	**1,005.1**	1,006.1
Earnings (loss) per share – basic *($/share)*	**(1.40)**	1.41
Earnings (loss) per share – diluted *($/share)*	**(1.41)**	1.40

(1) *For the year ended December 31, 2019, equity-settlement of stock options was used to calculate diluted earnings (loss) per share as it was considered more dilutive than cash-settlement (December 31, 2018 – equity-settlement method was used). Stock-based compensation recovery was $6 million based on cash-settlement for the year ended December 31, 2019 (2018 – recovery of $3 million). Stock-based compensation expense would have been $9 million based on equity-settlement for the year ended December 31, 2019 (2018 – $10 million).*

For the year ended December 31, 2019, 18 million tandem options (2018 – 13 million) were excluded from the calculation of diluted earnings (loss) per share as these options were anti-dilutive.

Note 21 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 (loss) for the years ended December 31, 2019 and 2018:

Production, Operating and Transportation Expenses

($ millions)	**2019**	2018
Services and support costs	**1,255**	1,039
Salaries and benefits	**773**	762
Materials, equipment rentals and leases	**250**	243
Energy and utility	**482**	405
Licensing fees	**204**	191
Transportation	**17**	24
Other	**36**	139
Total production, operating and transportation expenses	**3,017**	2,803

The following table summarizes selling, general and administrative expenses in the consolidated statements of income (loss) for the years ended December 31, 2019 and 2018:

Selling, General and Administrative Expenses

($ millions)	**2019**	2018
Employee costs[(1)]	**450**	332
Stock-based compensation expense (recovery)[(2)]	**(2)**	44
Contract services	**133**	104
Equipment rentals and leases	**11**	39
Maintenance and other	**101**	135
Total selling, general and administrative expenses	**693**	654

(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 22 Financial Items

Financial Items

($ millions)	**2019**	2018
Foreign exchange gain (loss)		
Non-cash working capital	**17**	(3)
Other foreign exchange	**27**	17
Net foreign exchange gain	**44**	14
Finance income	**74**	64
Finance expenses		
Long-term debt	**(310)**	(320)
Lease liabilities[(1)] *(note 10)*	**(106)**	—
Other	**(6)**	(5)
	(422)	(325)
Interest capitalized[(2)]	**177**	108
	(245)	(217)
Accretion of asset retirement obligations *(note 17)*	**(106)**	(97)
Finance expenses	**(351)**	(314)
Total Financial Items	**(233)**	(236)

(1) *Includes $5 million of interest allocated to the carrying amount of assets in Oil and Gas Properties.*
(2) *Interest capitalized on project costs is calculated using the Company's annualized effective interest rate of 5% (2018 – 5%).*

Note 23 Pensions and Other Post-employment Benefits

The Company currently provides defined contribution pension plans for all qualified employees and 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 one defined benefit pension plan, which is closed to new entrants. The defined benefit pension plan provides pension benefits to certain employees based on years of service and final average earnings. The amount and timing of funding of this plan 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, 2019. 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, 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, 2019, the Company recognized a $59 million expense (2018 – $54 million) for the defined contribution and U.S. 401(k) plans in net earnings (loss).

Defined Benefit Pension Plans ("DB Pension Plan") and Other Post-employment Benefit Plans ("OPEB Plans")

Defined Benefit Obligations	DB Pension Plans		OPEB Plans	
($ millions)	**2019**	2018	**2019**	2018
Beginning of year	**79**	76	**199**	244
Current service cost	**—**	1	**10**	11
Interest cost	**2**	3	**7**	8
Benefits paid	**(3)**	(2)	**(4)**	(4)
Past service cost	**3**	—	**(29)**	—
Settlements	**(49)**	—	**—**	—
Remeasurements				
Actuarial (gain) loss – experience	**—**	2	**(1)**	(13)
Actuarial (gain) loss – financial assumptions	**9**	(4)	**20**	(45)
Effect of changes in foreign exchange rates	**(2)**	3	**(1)**	(2)
End of year	**39**	79	**201**	199

Fair Value of Plan Assets	DB Pension Plans		OPEB Plans	
($ millions)	**2019**	2018	**2019**	2018
Beginning of year	**71**	67	**—**	—
Contributions by employer	**(1)**	1	**2**	2
Benefits paid	**(3)**	(2)	**(2)**	(2)
Interest income	**2**	2	**—**	—
Return on plan assets greater than discount rate	**16**	—	**—**	—
Settlements	**(52)**	—	**—**	—
Effect of changes in foreign exchange rates	**(2)**	3	**—**	—
End of year	**31**	71	**—**	—

Funded status	DB Pension Plans		OPEB Plans	
($ millions)	**2019**	2018	**2019**	2018
Net asset (liability)	**(8)**	(8)	**(201)**	(199)

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 25, 2019, the Company completed the transaction related to the Canadian DB Pension Plan initiated on July 25, 2017. The transaction settled the remaining service costs for active plan members, thereby settling the defined benefit obligation related to active plan members. This resulted in the Company recognizing a $5 million actuarial gain (net of tax of $1 million) in other comprehensive income (loss) in 2019.

The composition of the DB Pension Plan assets at December 31, 2019 and 2018 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	**2019**	2018
Money market type funds	—	**—**	5
Equity securities	35	**35**	—
Debt securities	65	**65**	95

The following table summarizes amounts recognized in net earnings (loss) and OCI for the DB Pension Plans and the OPEB Plans for the years ended December 31, 2019 and 2018:

	DB Pension Plans		OPEB Plans	
($ millions)	**2019**	2018	**2019**	2018
Amounts recognized in net earnings (loss)				
Current service cost	**—**	1	**10**	11
Past service cost	**3**	—	**(29)**	—
Net Interest cost	**—**	1	**7**	8
Benefit cost	**3**	2	**(12)**	19
Remeasurements				
Actuarial loss (gain) due to liability experience	**—**	2	**(1)**	(13)
Actuarial loss (gain) due to liability assumption changes	**9**	(4)	**20**	(45)
(Gain) loss on plan assets	**(16)**	—	**—**	—
Remeasurement effects recognized in OCI	**(7)**	(2)	**19**	(58)

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 Plans		OPEB Plans	
(percent)	**2019**	2018	**2019**	2018
Discount rate for benefit expense and obligation	**2.3 - 4.2**	3.4 - 3.6	**3.0 - 3.7**	3.4 - 3.7
Rate of compensation expense	**3.5**	N/A	**N/A**	N/A

The average health care cost trend rate used for the benefit expense for the Canadian OPEB Plan was 6.0% for 2018, 2019 and 2020, grading 0.5% per year for 2 years to 5.0% in 2022 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 6.0% for 2018, 2019 and 2020, grading 0.5% per year for 2 years to 5.0% 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% for 2018, grading 0.25% per year for 5 years to 5.0% 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% for 2019 and 2020, grading 0.25% per year for 6 years to 5.0% 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 Plans		OPEB Plans	
($ millions)	1% increase	1% decrease	1% increase	1% decrease
Discount rate	(4)	5	(23)	28
Health care cost trend rate	N/A	N/A	(16)	18

Note 24 Cash Flows – Change in Non-cash Working Capital

Non-cash Working Capital

($ millions)	2019	2018
Decrease (increase) in non-cash working capital		
Accounts receivable	**(176)**	127
Inventories	**(502)**	393
Prepaid expenses	**(30)**	30
Accounts payable and accrued liabilities	**604**	(65)
Change in non-cash working capital	**(104)**	485
Relating to:		
Operating activities	**(280)**	130
Financing activities	**3**	120
Investing activities	**173**	235

Note 25 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, lease liabilities 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, 2019	December 31, 2018
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas(1)	**31**	(9)
Crude oil(2)	**11**	89
Crude oil call options(3)	**(2)**	—
Crude oil put options(3)	**(4)**	—
Foreign currency contracts – FVTPL		
Foreign currency forwards	**2**	(1)
Other assets – FVTPL	**1**	1
End of year	**39**	80

(1) *Natural gas contracts includes a $4 million decrease at December 31, 2019 (December 31, 2018 – $10 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 $19 million at December 31, 2019 (December 31, 2018 – $15 million).*

(2) *Crude oil contracts includes a $12 million increase at December 31, 2019 (December 31, 2018 – $67 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 $136 million at December 31, 2019 (December 31, 2018 – $185 million).*

(3) *Excludes net unsettled premiums of $6 million.*

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, 2019, the carrying value of the Company's long-term debt was $5.0 billion and the estimated fair value was $5.3 billion (December 31, 2018 – carrying value of $5.5 billion, estimated fair value of $5.7 billion).

All financial assets and liabilities are classified as Level 2 fair value measurements, except commodity put and call options under a short-term hedging program, which are classified as Level 1 fair value measurements as they are determined using quoted market prices. During the year ended December 31, 2019, 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.

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 30, 2019, 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, 2019, the net unrealized loss recognized on the derivative contracts was $38 million (2018 – net unrealized gain of $150 million).

During the year ended December 31, 2019, the Company entered into a commodity short-term hedging program using put and call options to manage risks related to volatility of commodity prices.

Western Texas Intermediate Crude Oil Call and Put Option Contracts[1]

Type	Transaction	Term	Volume (bbls/day)	Call Price (US$bbl)	Put Price (US$bbl)
Call options	Sold	January - March 2020	**35,714**	**60.50**	**—**
Put options	Bought	January - March 2020	**36,263**	**—**	**55.61**
Put options	Sold	January - March 2020	**20,055**	**—**	**50.77**

[1] *Prices reported are the weighted average prices for the period.*

For the year ended December 31, 2019, the Company incurred an unrealized loss of $6 million (December 31, 2018 – nil). For the year ended December 31, 2019, the Company incurred a realized gain of $16 million (December 31, 2018 – nil).These amounts are recorded in other – net in the consolidated statements of income (loss).

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, 2019, the Company had designated US $2.4 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, 2018 – US$2.7 billion). For the year ended December 31, 2019, the unrealized gain arising from the translation of the debt was $146 million (December 31, 2018 – unrealized loss of $262 million), net of tax expense of $30 million (December 31, 2018 – recovery of $41 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.

IV) 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, 2019 Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	**79**	**(26)**	**53**
Normal purchase and sale agreements	**817**	**(274)**	**543**
End of year	**896**	**(300)**	**596**
Financial Liabilities			
Financial derivatives	**(48)**	**25**	**(23)**
Normal purchase and sale agreements	**(843)**	**281**	**(562)**
End of year	**(891)**	**306**	**(585)**

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)

V) Market Risk Sensitivity Analysis

A sensitivity analysis for commodities and foreign currency exchange risks has been calculated by increasing or decreasing commodity prices or foreign currency exchange rates, as appropriate. These sensitivities represent the increase or decrease in earnings (loss) 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	13	(13)
Natural gas price	(2)	2

Foreign Exchange Rate[2] ($ millions)	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar	1	(1)

[1] *Based on average crude oil and natural gas market prices as at December 31, 2019.*
[2] *Based on the U.S./Canadian dollar exchange rate as at December 31, 2019.*

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 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 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, 2019:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1] *(note 14)*	**900**	**464**
Syndicated bank facilities[2] *(note 16)*	**4,000**	**3,450**
End of year	**4,900**	**3,914**

[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$2.25 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% of gross revenues during the years ended December 31, 2019 and December 31, 2018. Sales to this customer were approximately $3.9 billion for the year ended December 31, 2019 (December 31, 2018 – $4.2 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, 2019:

Accounts Receivable Aging

($ millions)	December 31, 2019
Current	**1,418**
Past due (1 - 30 days)	**64**
Past due (31 - 60 days)	**4**
Past due (61 - 90 days)	**—**
Past due (more than 90 days)	**47**
Provision for expected credit losses	**(34)**
	1,499

The Company recognizes a valuation provision when collection of accounts receivable is in doubt. Accounts receivable are impaired directly when collection is no longer expected. For the year ended December 31, 2019, the Company wrote off $4 million (December 31, 2018 – $3 million) of uncollectible receivables.

Note 26 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, 2019. All of the entities listed below, except as otherwise indicated, are 100% 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(1)	100	Alberta
Husky Downstream General Partnership(1)	100	Alberta
Husky Energy Marketing Partnership	100	Alberta
Sunrise Oil Sands Partnership	50	Alberta
BP-Husky Refining LLC	50	Delaware

(1) Dissolved effective January 1, 2020, assets were transferred to 2188787 Alberta ULC.

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% 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, 2019, the Company charged HMLP $424 million (December 31, 2018 – $448 million) related to construction costs and management services. For the year ended December 31, 2019, the Company had purchases from HMLP of $219 million (December 31, 2018 – $200 million) related to the use of the pipeline for the Company's blending activities, transportation and storage activities, received distributions of $94 million (December 31, 2018 – $139 million) and paid capital contributions of $37 million (December 31, 2018 – $40 million). At December 31, 2019, the Company had $143 million due from HMLP, of which nil relates to unbilled revenue from construction contracts (December 31, 2018 – $140 million and nil, respectively). At December 31, 2019, the Company had $16 million due to HMLP (December 31, 2018 – nil).

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)	**2019**	2018
Short-term employee benefits[(1)]	**18**	17
Stock-based compensation[(2)]	**26**	33
	44	50

[(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 27 Commitments and Contingencies

At December 31, 2019, 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 agreements[(1)]	75	310	666	1,051
Firm transportation agreements[(1)]	576	2,377	4,203	7,156
Unconditional purchase obligations[(2)]	2,224	5,517	5,143	12,884
Lease rentals and exploration work agreements	79	215	866	1,160
Obligations to fund equity investee[(3)]	54	290	359	703
	3,008	8,709	11,237	22,954

[(1)] *Included in operating agreements and firm transportation agreements are blending and storage agreements and transportation commitments of $1.1 billion and $1.8 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.*

During the three months ended December 31, 2019, the Company entered into an agreement totaling an incremental $2.2 billion for a term of 5 years to purchase refined products to support the retail network.

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 28 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 $22.8 billion as at December 31, 2019 (December 31, 2018 – $25.4 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 its financing requirements and capital structure 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 excluding change in non-cash working capital.

At December 31, 2019, debt to capital employed was 24.2% (December 31, 2018 – 22.7%) and debt to funds from operations was 1.7 times (December 31, 2018 – 1.4 times). The Company is subject to a leverage covenant in its credit facilities that limits debt to capital (subject to specific definitions in the credit agreements) to less than 65%. The Company is in compliance with this covenant and considers the risk of non-compliance low. The Company also targets a debt to funds from operations ratio of less than 2.0 times over the longer term.

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.

There were no changes in the Company's approach to capital management from the previous year.

Note 29 Subsequent Event

Reclassification of Segmented Financial Information

Commencing in the first quarter of 2020, the Company's segmented financial information will be reported as the Integrated Corridor and Offshore business segments.

Integrated Corridor

The Company's business in the Integrated Corridor includes: crude oil, bitumen, conventional natural gas, NGL and ethanol production from Western Canada; marketing and transportation of the Company's and other producers' production; the Upgrader and Asphalt Refinery; Husky Midstream Limited Partnership (35% working interest and operatorship); the Lima Refinery, the BP-Husky Toledo Refinery (50% working interest) and the Superior Refinery in the U.S. Midwest; and the marketing of refined petroleum products including gasoline, diesel and ethanol blended fuels through petroleum outlets. Conventional 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 Asia Pacific and Atlantic.

The revised segmentation is consistent with the Company's strategic view of its business and is in alignment with how the Company's results are assessed by management. If the reclassification of the segmented financial information were to have occurred in 2019, the 2018 and 2019 segmented financial information would have reflected this change as follows:

Segmented Financial Information - Reclassified

($ millions)	Integrated Corridor									
	Lloyd Heavy Oil Value Chain		Oil Sands		Western Canada Production		U.S. Refining		Canadian Refined Products	
Year ended December 31,	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Gross revenues	**5,117**	5,308	**931**	405	**506**	661	**10,250**	11,777	**2,425**	2,752
Royalties	**(160)**	(137)	**(13)**	(12)	**(41)**	(58)	**—**	—	**—**	—
Marketing and other	**60**	458	**4**	166	**101**	86	**24**	(42)	**—**	—
Revenues, net of royalties	**5,017**	5,629	**922**	559	**566**	689	**10,274**	11,735	**2,425**	2,752
Expenses										
Purchases of crude oil and products	**1,829**	2,217	**528**	306	**39**	140	**8,935**	10,342	**2,174**	2,435
Production, operating and transportation expenses	**1,209**	1,121	**140**	132	**308**	302	**869**	795	**153**	151
Selling, general and administrative expenses	**154**	129	**27**	28	**105**	106	**51**	40	**9**	10
Depletion, depreciation, amortization and impairment	**941**	887	**938**	95	**1,034**	292	**735**	450	**83**	80
Exploration and evaluation expenses	**54**	32	**2**	18	**111**	28	**—**	—	**—**	—
Loss (gain) on sale of assets	**—**	(1)	**—**	—	**(2)**	(1)	**1**	—	**(6)**	(2)
Other – net	**103**	(106)	**(28)**	—	**2**	5	**(654)**	(464)	**—**	(1)
	4,290	4,279	**1,607**	579	**1,597**	872	**9,937**	11,163	**2,413**	2,673
Earnings (loss) from operating activities	**727**	1,350	**(685)**	(20)	**(1,031)**	(183)	**337**	572	**12**	79
Share of equity investment income	**9**	18	**—**	—	**—**	—	**—**	—	**—**	—
Financial items										
Net foreign exchange gain (loss)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Finance income	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Finance expenses	**(48)**	(43)	**(59)**	(21)	**(24)**	(19)	**(18)**	(14)	**(13)**	(11)
	(48)	(43)	**(59)**	(21)	**(24)**	(19)	**(18)**	(14)	**(13)**	(11)
Earnings (loss) before income taxes	**688**	1,325	**(744)**	(41)	**(1,055)**	(202)	**319**	558	**(1)**	68
Provisions for (recovery of) income taxes										
Current	**(2)**	(3)	**10**	—	**—**	—	**17**	9	**—**	—
Deferred	**186**	365	**(209)**	(11)	**(283)**	(55)	**54**	115	**—**	19
	184	362	**(199)**	(11)	**(283)**	(55)	**71**	124	**—**	19
Net earnings (loss)	**504**	963	**(545)**	(30)	**(772)**	(147)	**248**	434	**(1)**	49
Intersegment revenues	**452**	693	**—**	—	**205**	233	**—**	5	**4**	6
Expenditures on exploration and evaluation assets(1)	**17**	18	**—**	—	**3**	99	**—**	—	**—**	—
Expenditures on property, plant and equipment(1)	**939**	1,070	**38**	51	**191**	322	**768**	666	**73**	40
As at December 31,										
Total assets	**8,312**	7,707	**2,757**	3,237	**1,709**	2,534	**8,645**	8,558	**838**	917

(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.*

Segmented Financial Information - Reclassified Con't

Integrated Corridor				Offshore		Corporate		Total	
Eliminations		Total							
2019	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
(664)	(937)	**18,565**	19,966	**1,552**	1,953	**—**	—	**20,117**	21,919
—	—	**(214)**	(207)	**(109)**	(128)	**—**	—	**(323)**	(335)
—	—	**189**	668	**—**	—	**—**	—	**189**	668
(664)	(937)	**18,540**	20,427	**1,443**	1,825	**—**	—	**19,983**	22,252
(664)	(937)	**12,841**	14,503	**(24)**	52	**—**	—	**12,817**	14,555
—	—	**2,679**	2,501	**340**	304	**(2)**	(2)	**3,017**	2,803
—	—	**346**	313	**55**	58	**292**	283	**693**	654
—	—	**3,731**	1,804	**1,661**	695	**104**	92	**5,496**	2,591
—	—	**167**	78	**380**	71	**—**	—	**547**	149
—	—	**(7)**	(4)	**(1)**	—	**—**	—	**(8)**	(4)
—	—	**(577)**	(566)	**9**	(19)	**(16)**	(6)	**(584)**	(591)
(664)	(937)	**19,180**	18,629	**2,420**	1,161	**378**	367	**21,978**	20,157
—	—	**(640)**	1,798	**(977)**	664	**(378)**	(367)	**(1,995)**	2,095
—	—	**9**	18	**50**	51	**—**	—	**59**	69
—	—	**—**	—	**—**	—	**44**	14	**44**	14
—	—	**—**	—	**3**	12	**71**	52	**74**	64
—	—	**(162)**	(108)	**(38)**	(28)	**(151)**	(178)	**(351)**	(314)
—	—	**(162)**	(108)	**(35)**	(16)	**(36)**	(112)	**(233)**	(236)
—	—	**(793)**	1,708	**(962)**	699	**(414)**	(479)	**(2,169)**	1,928
—	—	**25**	6	**125**	141	**25**	(72)	**175**	75
—	—	**(252)**	433	**(393)**	35	**(329)**	(72)	**(974)**	396
—	—	**(227)**	439	**(268)**	176	**(304)**	(144)	**(799)**	471
—	—	**(566)**	1,269	**(694)**	523	**(110)**	(335)	**(1,370)**	1,457
—	—	**661**	937	**—**	—	**—**	—	**661**	937
—	—	**20**	117	**26**	125	**—**	—	**46**	242
—	—	**2,009**	2,149	**1,246**	1,066	**131**	121	**3,386**	3,336
—	—	**22,261**	22,953	**8,077**	8,627	**2,784**	3,645	**33,122**	35,225

Supplemental Financial and Operating Information

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2019**	2018	2017	2016	2015	2014	2013	2012[1]	2011[1]	2010[2][3]
Financial Highlights										
Gross Revenues and Marketing and Other	**20,306**	22,587	18,946	13,224	16,801	25,122	24,181	22,948	22,829	18,085
Net earnings (loss)	**(1,370)**	1,457	786	922	(3,850)	1,258	1,829	2,022	2,224	947
Earnings (loss) per share										
Basic	**(1.40)**	1.41	0.75	0.88	(3.95)	1.26	1.85	2.06	2.40	1.11
Diluted	**(1.41)**	1.40	0.75	0.88	(4.01)	1.20	1.85	2.06	2.34	1.05
Capital expenditures[4]	**3,432**	3,578	2,220	1,705	3,005	5,023	5,028	4,701	4,618	3,571
Total debt[8]	**5,520**	5,747	5,440	5,339	6,756	5,292	4,119	3,918	3,911	4,187
Debt to capital employed *(%)*[5]	**24.2**	22.7	23.2	23.2	28.9	20.0	17.0	17.0	18.0	22.0
Upstream										
Daily production, before royalties										
Crude oil & NGLs *(mboe/day)*	**206.5**	214.7	233.0	228.6	230.9	236.6	226.5	209.2	211.3	202.6
Conventional natural gas *(mmcf/day)*	**500.9**	507.0	539.1	559.9	689.0	621.0	512.7	554.0	607.0	506.8
Total production *(mboe/day)*	**290.0**	299.2	322.9	321.2	345.7	340.1	312.0	301.5	312.5	287.1
Total proved reserves, before royalties *(mmboe)*[6]	**1,431**	1,471	1,301	1,224	1,324	1,279	1,265	1,192	1,172	1,081
Downstream										
Upgrading										
Synthetic crude oil sales *(mbbls/day)*	**55.4**	52.9	49.8	55.2	51.1	53.3	50.5	60.4	55.3	54.1
Upgrading differential *($/bbl)*	**17.19**	29.05	18.66	20.74	18.66	21.80	29.14	22.34	27.34	14.52
Canadian Refined Products										
Fuel sales *(million of litres/day)*[7]	**7.4**	7.7	7.3	6.6	7.6	8.0	8.1	8.7	9.5	8.2
Refinery throughput										
Prince George Refinery *(mbbls/day)*[12]	**7.2**	10.7	11.2	9.4	10.7	11.7	10.3	11.1	10.6	10.0
Lloydminster Refinery *(mbbls/day)*	**26.4**	27.1	26.8	27.8	28.1	28.8	26.4	28.3	28.1	27.8
U.S. Refining and Marketing										
Refinery throughput										
Lima Refinery *(mbbls/day)*	**136.4**	151.1	172.2	138.2	136.1	141.6	149.4	150.0	144.3	136.6
BP-Husky Toledo Refinery *(mbbls/day)*[9]	**63.1**	71.1	76.6	62.2	68.2	63.2	65.0	60.6	63.9	64.4
Superior Refinery *(mbbls/day)*[10]	**—**	11.7	5.5	—	—	—	—	—	—	—
Refining and marketing margin *(U.S. $/bbl crude throughput)*[11]	**13.83**	13.03	11.44	8.94	10.09	9.37	15.06	17.48	17.60	7.29

(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 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 are prepared in accordance with the Canadian Securities Administrators' National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." 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 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.
(12) Sale of the Prince George Refinery closed on November 1, 2019.

Upstream Operating Information

	2019	2018	2017	2016	2015
Daily Production, before royalties					
Light & Medium crude oil *(mbbls/day)*	**24.9**	30.8	51.4	63.1	80.5
NGL *(mbbls/day)*[(3)]	**22.6**	22.9	18.1	14.0	18.2
Heavy crude oil *(mbbls/day)*	**30.2**	36.8	44.4	54.1	69.1
Bitumen *(mbbls/day)*[(3)]	**128.8**	124.2	119.1	97.4	63.1
	206.5	214.7	233.0	228.6	230.9
Conventional natural gas *(mmcf/day)*	**500.9**	507.0	539.1	555.9	689.0
Total production *(mboe/day)*	**290.0**	299.2	322.9	321.2	345.7
Average sales prices					
Light & Medium crude oil *($/bbl)*	**72.85**	83.71	67.36	52.40	57.55
NGL *($/bbl)*[(3)]	**44.99**	55.72	44.18	38.01	45.88
Heavy crude oil *($/bbl)*	**54.70**	39.26	43.38	30.50	37.16
Bitumen *($/bbl)*	**49.00**	30.17	38.20	27.63	34.47
Conventional natural gas *($/mcf)*[(3)]	**6.44**	6.64	5.52	4.40	5.80
Operating costs *($/boe)*	**15.53**	14.00	13.93	14.04	15.14
Operating netbacks[(1)(2)(3)]					
Light & Medium crude oil *($/bbl)*	**25.60**	45.44	39.83	23.82	29.40
NGL *($/bbl)*	**31.86**	39.53	27.05	22.99	32.10
Heavy crude oil *($/bbl)*	**14.78**	7.41	15.33	9.25	14.56
Bitumen *($/bbl)*	**33.82**	16.65	24.85	15.21	15.41
Conventional natural gas *($/mcf)*	**4.71**	4.99	3.67	2.51	3.93

(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%). 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]	2019	2018	2017
Upstream			
Crude Oil Equivalent *($/boe)*[2]			
Sales volume *(mboe/day)*	**290.0**	299.2	322.9
Gross revenue *($/boe)*[6]	**48.37**	41.50	42.47
Royalties *($/boe)*	**3.29**	3.30	3.07
Production and operating costs *($/boe)*[6]	**15.53**	14.00	13.93
Offshore transportation *($/boe)*[3]	**0.16**	0.22	0.22
Operating netback *($/boe)*	**29.39**	23.98	25.25
Depletion, depreciation, amortization and impairment *($/boe)*	**41.17**	16.99	19.08
Administration expenses and other *($/boe)*	**3.90**	3.57	3.13
Earnings (loss) before taxes *($/boe)*	**(15.68)**	3.42	3.04
Operating netbacks by commodity			
Crude Oil & NGL's Total[7]			
Sales volume *(mboe/day)*	**206.5**	214.7	233.0
Gross revenue *($/boe)*[6]	**52.28**	42.16	46.09
Royalties *($/boe)*	**3.81**	3.92	3.92
Production and operating costs *($/boe)*[6]	**18.42**	16.30	15.36
Offshore transportation *($/boe)*[3]	**0.23**	0.30	0.31
Operating netback *($/boe)*	**29.82**	21.64	26.50
Conventional Natural Gas Total[7]			
Sales volume *(mmcf/day)*	**500.9**	507.0	539.1
Gross revenue *($/mcf)*[7]	**6.44**	6.64	5.52
Royalties *($/mcf)*	**0.33**	0.29	0.15
Production and operating costs *($/mcf)*[6]	**1.40**	1.36	1.70
Operating netback *($/mcf)*	**4.71**	4.99	3.67
Thermal Development			
Lloydminster Thermal			
Bitumen			
Sales volumes *(mbbls/day)*	**80.5**	76.8	77.1
Gross revenue *($/bbl)*[6]	**52.11**	35.39	40.53
Royalties *($/bbl)*	**2.93**	2.41	2.76
Production and operating costs *($/bbl)*[6]	**12.51**	10.54	10.21
Operating netback *($/bbl)*	**36.67**	22.44	27.56
Tucker Thermal			
Bitumen			
Sales volumes *(mbbls/day)*	**23.7**	22.4	21.9
Gross revenue *($/bbl)*[6]	**49.99**	29.76	37.73
Royalties *($/bbl)*	**1.91**	1.82	0.90
Production and operating costs *($/bbl)*[6]	**10.59**	11.12	9.84
Operating netback *($/bbl)*	**37.49**	16.82	26.99
Sunrise Energy Project			
Bitumen			
Sales volumes *(mbbls/day)*	**24.6**	25.0	20.1
Gross revenue *($/bbl)*[6]	**37.85**	14.50	29.79
Royalties *($/bbl)*	**1.42**	1.36	0.77
Production and operating costs *($/bbl)*[6]	**15.52**	14.43	16.91
Operating netback *($/bbl)*	**20.91**	(1.29)	12.11
Thermal Development Bitumen Total			
Sales volumes *(mbbls/day)*	**128.8**	124.2	119.1
Gross revenue *($/bbl)*[7]	**49.00**	30.17	38.20
Royalties *($/bbl)*	**2.45**	2.09	2.08
Production and operating costs *($/bbl)*[6]	**12.73**	11.43	11.27
Operating netback *($/bbl)*	**33.82**	16.65	24.85

Operating Netback Analysis (continued)	2019	2018	2017
Non - Thermal Development			
Medium Oil			
Sales volumes *(mbbls/day)*	**1.5**	1.9	2.1
Gross revenue *($/bbl)*(6)	**57.29**	43.91	48.30
Royalties *($/bbl)*	**3.14**	2.31	2.41
Heavy Oil			
Sales volumes *(mbbls/day)*	**30.2**	36.8	43.5
Gross revenue *($/bbl)*(6)	**54.70**	39.25	43.41
Royalties *($/bbl)*	**5.08**	3.86	4.42
Conventional Natural Gas			
Sales volumes *(mmcf/day)*	**15.7**	19.6	24.6
Gross revenue *($/mcf)*(6)	**1.31**	1.66	2.02
Royalties ($/mcf)	**0.08**	0.07	0.11
Non - Thermal Development Medium Oil, Heavy Oil & Conventional Natural Gas Total(2)			
Sales volumes *(mboe/day)*	**34.4**	42.0	49.7
Gross revenue *($/boe)*(6)	**51.27**	37.18	41.04
Royalties *($/boe)*	**4.65**	3.53	4.03
Production and operating costs *($/boe)*(6)	**31.85**	26.67	22.21
Operating netback *($/boe)*	**14.77**	6.98	14.80
Western Canada			
Crude Oil			
Light & Medium Oil			
Sales volumes *(mbbls/day)*	**7.0**	7.5	10.0
Gross revenue *($/bbl)*(6)	**44.85**	58.70	54.13
Royalties *($/bbl)*	**10.47**	10.42	6.97
Heavy Oil			
Sales volumes *(mbbls/day)*	**—**	—	0.9
Gross revenue *($/bbl)*(6)	**—**	—	42.14
Royalties *($/bbl)*	**—**	—	4.86
Western Canada Crude Oil Total			
Sales volumes *(mbbls/day)*	**7.0**	7.5	10.9
Gross revenue *($/bbl)*(6)	**44.85**	58.70	53.15
Royalties *($/bbl)*	**10.47**	10.42	6.80
Production and operating costs *($/bbl)*(6)	**29.18**	31.17	33.69
Operating netback *($/bbl)*	**5.20**	17.11	12.66
Conventional Natural Gas & NGLs			
NGLs			
Sales volumes *(mbbls/day)*	**12.7**	12.0	10.5
Gross revenue *($/bbl)*(6)	**23.38**	35.71	32.08
Royalties *($/bbl)*	**3.44**	9.58	10.16
Conventional Natural Gas			
Sales volumes *(mmcf/day)*	**281.8**	271.4	353.6
Gross revenue *($/mcf)*(4)(6)	**1.74**	1.80	2.31
Royalties *($/mcf)*(4)(5)	**(0.02)**	(0.13)	(0.12)
Western Canada Conventional Natural Gas and NGL Total(2)			
Sales volumes *(mmcfe/day)*	**357.8**	343.4	416.6
Gross revenue *($/mcfe)*(6)	**2.20**	2.67	2.77
Royalties *($/mcfe)*	**0.11**	0.23	0.15
Production and operating costs *($/mcfe)*(7)	**1.70**	1.66	2.02
Operating netback *($/mcfe)*	**0.39**	0.78	0.60

Operating Netback Analysis (continued)	2019	2018	2017
Atlantic			
Light Oil			
Sales volumes *(mbbls/day)*	**16.4**	21.4	34.0
Gross revenue *($/bbl)*	**86.44**	95.97	71.69
Royalties *($/bbl)*	**8.15**	7.90	6.75
Production and operating costs *($/bbl)*	**42.20**	27.21	17.12
Offshore transportation *($/bbl)*[3]	**2.89**	3.01	2.13
Operating netback *($/bbl)*	**33.20**	57.85	45.69
Asia Pacific – China			
Light Oil			
Sales volumes *(mbbls/day)*	**—**	—	5.3
Gross revenue *($/bbl)*	**—**	—	72.08
Royalties *($/bbl)*	**—**	—	5.08
NGLs			
Sales volumes *(mbbls/day)*	**7.4**	8.4	7.0
Gross revenue *($/bbl)*	**67.28**	72.77	59.50
Royalties *($/bbl)*	**3.82**	4.21	3.38
Conventional Natural Gas			
Sales volumes *(mmcf/day)*	**171.0**	184.8	152.9
Gross revenue *($/mcf)*	**14.02**	13.73	13.29
Royalties *($/mcf)*	**0.80**	0.80	0.74
Asia Pacific – China Light Oil, NGLs & Conventional Natural Gas Total[2]			
Sales volumes *(mboe/day)*	**35.9**	39.2	37.8
Gross revenue *($/boe)*	**80.64**	80.31	74.94
Royalties *($/boe)*	**4.55**	4.67	4.33
Production and operating costs *($/boe)*	**5.43**	4.59	6.16
Operating netback *($/boe)*	**70.66**	71.05	64.45
Asia Pacific – Indonesia[7]			
NGLs			
Sales volumes *(mbbls/day)*	**2.5**	2.5	0.6
Gross revenue *($/bbl)*	**88.91**	95.67	77.79
Royalties *($/bbl)*	**13.75**	14.96	12.32
Conventional Natural Gas			
Sales volumes *(mmcf/day)*	**32.4**	31.2	8.0
Gross revenue *($/mcf)*	**9.87**	9.81	9.51
Royalties *($/mcf)*	**1.10**	1.07	1.03
Asia Pacific – Indonesia NGLs & Conventional Natural Gas Total[2]			
Sales volumes *(mboe/day)*	**7.9**	7.7	1.9
Gross revenue *($/boe)*	**68.58**	70.60	63.46
Royalties *($/boe)*	**8.86**	9.15	8.08
Production and operating costs *($/boe)*	**8.39**	10.04	12.59
Operating netback *($/boe)*	**51.33**	51.41	42.79

Operating Netback Analysis (continued)	2019	2018	2017
Asia Pacific – Total(7)			
Light Oil			
Sales volumes *(mbbls/day)*	**—**	—	5.3
Gross revenue *($/bbl)*	**—**	—	72.08
Royalties *($/bbl)*	**—**	—	5.08
NGLs			
Sales volumes *(mbbls/day)*	**9.9**	10.9	7.6
Gross revenue *($/bbl)*	**72.70**	77.94	60.94
Royalties *($/bbl)*	**6.31**	6.64	4.08
Conventional Natural Gas			
Sales volumes *(mmcf/day)*	**203.4**	216.0	160.9
Gross revenue *($/mcf)*	**13.36**	13.16	13.10
Royalties *($/mcf)*	**0.85**	0.84	0.76
Asia Pacific Light Oil, NGLs & Conventional Natural Gas Total(2)			
Sales volumes *(mboe/day)*	**43.8**	46.9	39.7
Gross revenue *($/boe)*	**78.47**	78.72	74.38
Royalties *($/boe)*	**5.34**	5.40	4.52
Production and operating costs *($/boe)*	**6.03**	5.53	6.47
Operating netback *($/boe)*	**67.10**	67.79	63.39

(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%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.

Segmented Financial Information

	Upstream										Downstream				
	Exploration and Production[1]					Infrastructure and Marketing					Upgrading				
($ millions)	**2019**	2018	2017	2016	2015	**2019**	2018	2017	2016	2015	**2019**	2018	2017	2016	2015
Year ended December 31															
Gross revenues	**4,958**	4,330	4,978	4,036	5,374	**2,342**	2,211	1,976	955	1,264	**1,777**	1,750	1,440	1,324	1,319
Royalties	**(323)**	(335)	(363)	(305)	(432)	**—**	—	—	—	—	**—**	—	—	—	—
Marketing and other	**—**	—	—	—	—	**189**	668	(40)	(88)	38	**—**	—	—	—	—
Revenues, net of royalties	**4,635**	3,995	4,615	3,731	4,942	**2,531**	2,879	1,936	867	1,302	**1,777**	1,750	1,440	1,324	1,319
Expenses															
Purchase of crude oil and products	**—**	—	—	32	41	**2,336**	2,087	1,855	857	1,123	**1,303**	928	983	808	922
Production, operating and transportation expenses	**1,634**	1,527	1,650	1,760	2,076	**21**	23	13	20	37	**217**	195	197	168	169
Selling, general and administrative expenses	**297**	296	265	232	237	**9**	5	4	5	7	**9**	7	9	4	4
Depletion, depreciation, amortization and impairment	**4,312**	1,811	2,237	1,815	7,993	**12**	—	2	13	25	**115**	123	99	103	106
Exploration and evaluation expenses	**547**	149	146	188	447	**—**	—	—	—	—	**—**	—	—	—	—
Loss (gain) on sale of assets	**(3)**	(2)	(42)	(192)	(17)	**—**	—	1	(1,439)	—	**—**	—	—	—	—
Other – net	**86**	(120)	6	53	(34)	**—**	2	(8)	(3)	(5)	**—**	—	—	(1)	(11)
Total Expenses	**6,873**	3,661	4,262	3,888	10,743	**2,378**	2,117	1,867	(547)	1,187	**1,644**	1,253	1,288	1,082	1,190
Earnings (loss) from operating activities	**(2,238)**	334	353	(157)	(5,801)	**153**	762	69	1,414	115	**133**	497	152	242	129
Share of equity investment gain (loss)	**50**	51	12	(1)	(5)	**9**	18	49	16	—	**—**	—	—	—	—
Net financial items	**(160)**	(97)	(126)	(140)	(139)	**(3)**	—	—	—	—	**(1)**	(1)	(1)	(1)	(1)
Earnings (loss) before income tax	**(2,348)**	288	239	(298)	(5,945)	**159**	780	118	1,430	115	**132**	496	151	241	128
Current income taxes	**32**	(484)	(34)	(100)	(41)	**—**	354	—	—	222	**63**	168	63	—	(17)
Deferred income taxes	**(674)**	549	99	19	(1,566)	**43**	(141)	32	122	(191)	**(28)**	(33)	(22)	66	52
Total income tax provision (recovery)	**(642)**	65	65	(81)	(1,607)	**43**	213	32	122	31	**35**	135	41	66	35
Net earnings (loss)	**(1,706)**	223	174	(217)	(4,338)	**116**	567	86	1,308	84	**97**	361	110	175	93
Total assets as at December 31	**17,533**	19,175	17,920	19,098	21,103	**1,661**	1,301	1,364	1,582	1,699	**1,203**	1,149	1,263	1,076	1,141

(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.*

Segmented Financial Information Con't

Downstream										Corporate and Eliminations[2]					Total				
Canadian Refined Products					U.S. Refining and Marketing														
2019	2018	2017	2016	2015	**2019**	2018	2017	2016	2015	**2019**	2018	2017	2016	2015	**2019**	2018	2017	2016	2015
3,122	3,412	2,787	2,301	2,886	**9,940**	11,770	9,355	5,995	7,345	**(2,022)**	(1,554)	(1,550)	(1,299)	(1,425)	**20,117**	21,919	18,986	13,312	16,763
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**(323)**	(335)	(363)	(305)	(432)
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**189**	668	(40)	(88)	38
3,122	3,412	2,787	2,301	2,886	**9,940**	11,770	9,355	5,995	7,345	**(2,022)**	(1,554)	(1,550)	(1,299)	(1,425)	**19,983**	22,252	18,583	12,919	16,369
2,571	2,760	2,219	1,770	2,281	**8,629**	10,334	8,059	5,188	6,455	**(2,022)**	(1,554)	(1,550)	(1,299)	(1,425)	**12,817**	14,555	11,566	7,356	9,397
278	265	256	241	238	**869**	795	563	535	474	**(2)**	(2)	—	—	—	**3,017**	2,803	2,679	2,724	2,994
53	47	53	43	31	**33**	22	15	13	10	**292**	277	304	247	53	**693**	654	650	544	342
218	115	111	102	103	**735**	450	354	342	333	**104**	92	79	87	84	**5,496**	2,591	2,882	2,462	8,644
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**547**	149	146	188	447
(6)	(2)	(5)	(3)	(5)	**1**	—	—	—	—	**—**	—	—	—	—	**(8)**	(4)	(46)	(1,634)	(22)
—	(1)	(1)	(10)	1	**(654)**	(464)	(21)	(176)	(236)	**(16)**	(8)	6	110	(2)	**(584)**	(591)	(18)	(27)	(287)
3,114	3,184	2,633	2,143	2,649	**9,613**	11,137	8,970	5,902	7,036	**(1,644)**	(1,195)	(1,161)	(855)	(1,290)	**21,978**	20,157	17,859	11,613	21,515
8	228	154	158	237	**327**	633	385	93	309	**(378)**	(359)	(389)	(444)	(135)	**(1,995)**	2,095	724	1,306	(5,146)
—	—	—	—	—	**—**	—	—	—	—	**—**	—	—	—	—	**59**	69	61	15	(5)
(15)	(12)	(12)	(7)	(6)	**(18)**	(14)	(14)	(3)	(3)	**(36)**	(112)	(208)	(220)	(71)	**(233)**	(236)	(361)	(371)	(220)
(7)	216	142	151	231	**309**	619	371	90	306	**(414)**	(471)	(597)	(664)	(206)	**(2,169)**	1,928	424	950	(5,371)
38	100	45	—	6	**17**	9	2	—	15	**25**	(72)	(79)	99	121	**175**	75	(3)	(1)	306
(40)	(42)	(7)	41	55	**52**	129	135	33	(106)	**(327)**	(66)	(596)	(252)	(71)	**(974)**	396	(359)	29	(1,827)
(2)	58	38	41	61	**69**	138	137	33	(91)	**(302)**	(138)	(675)	(153)	50	**(799)**	471	(362)	28	(1,521)
(5)	158	104	110	170	**240**	481	234	57	397	**(112)**	(333)	78	(511)	(256)	**(1,370)**	1,457	786	922	(3,850)
1,287	1,431	1,548	1,410	1,448	**8,691**	8,566	7,580	7,017	6,784	**2,747**	3,603	3,252	2,077	881	**33,122**	35,225	32,927	32,260	33,056

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, 2019 (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, including expectations for free cash flow generation in 2021; ability to increase shareholder returns and invest in higher margin projects that lower the Company's break-even oil price; and plans with respect to process and occupational safety;
- with respect to the Company's thermal developments: expected timing of first production from the Spruce Lake Central, Spruce Lake North and Spruce Lake East projects and plans for the Edam Central and Dee Valley 2 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 to the main project infrastructure at, and first gas production from, Liuhua 29-1; target production at Liuhua 29-1 and expected contributions to free cash flow; timing for drilling of development wells at MDA-MBH and expected timing for commenced of gas production and sales at MDA-MBH; and plans to develop the additional MDK field;
- with respect to the Company's Offshore business in Atlantic, the expected timing of start-up, and the expected volume and timing of peak production, at the West White Rose Project and expected contributions to free cash flow; and
- with respect to the Company's other operations in the Integrated Corridor: the expected timing that operations will resume at the Superior Refinery and expectation that the rebuild costs will be largely covered by insurance; plans to increase diesel capacity at the Lloydminster Upgrader, including timing for completion thereof; and timing for completion of the North Leg and Spruce Lake extensions at the Saskatchewan Gathering System.

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.

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, 2019 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 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 "net debt to trailing funds from operations", "sustaining capital", "break-even oil price" and "operating 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.

Net debt to trailing funds from operations is a non-GAAP measure that equals net debt divided by the 12-month trailing funds from operations as at December 31, 2019. Net debt to trailing funds from operations is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

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.

Break-even oil price reflects the estimated oil price per barrel required in order to generate funds flow from operations equal to the Company's sustaining capital requirements over the applicable period. This measure is calculated assuming that several variables are held constant throughout the applicable period, including foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels and other factors consistent with normal oil and gas company operations. Break-even oil price is used to assess the impact of changes in oil prices on the net earnings of the Company and could impact future investment decisions

Operating margin is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "revenue, net of royalties" as determined in accordance with IFRS, as an indicator of financial performance. Operating margin is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Operating margin equals revenues net of royalties less purchases of crude oil and products, production, operating and transportation expenses, and selling general and administrative expenses.

	Twelve months ended December 31, 2019
($ millions)	**Integrated Corridor**
Revenue, net of royalties	**20,541**
Less:	
Purchases of crude oil and products	**14,839**
Production and operating expenses	**2,678**
Selling, general and administrative expenses	**374**
Operating margin	**2,650**

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, 2019 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, 2019.

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 following table provides the full product breakdown for Upstream production, before royalties, for the periods indicated:

	Twelve Months Ended December 31	
	2019	2018
Upstream production, before royalties		
Light crude oil & medium (mbbls/day)	**25**	31
Heavy crude oil (mbbls/day)	**30**	37
Bitumen (mbbls/day)	**129**	124
Natural gas liquids (mbbls/day)	**23**	23
Conventional natural gas (mmcf/day)	**501**	507
Total equivalent production (mboe/day)	**290**	299

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(4)

Martin J.G. Glynn (1)(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)(4)

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 Rosenthal
Senior Vice President, Safety, Operations Integrity & Environment

Gerald F. Alexander
Senior Vice President, Western Canada

Bradley H. Allison
Senior Vice President, Exploration

Janet E. Annesley
Senior Vice President, Corporate Affairs & Human Resources

Jonathan D.S. Brown
Senior Vice President, Atlantic Region

P. Andrew Dahlin
Senior Vice President, Heavy Oil & Oil Sands

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

Jeffrey E. Rinker
Senior Vice President, Downstream

Investor Information

Common Share Information

Year ended December 31		**2019**	2018	2017
Share price *(dollars)*	High	**18.05**	22.99	17.83
	Low	**8.48**	13.33	13.39
	Close at December 31	**10.42**	14.11	17.75
Average daily trading volumes *(thousands)*		**2,210**	1,321	1,022
Number of common shares outstanding *(thousands)*		**1,005,122**	1,005,122	1,005,120
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**1,005,122**	1,005,121	1,005,309
	Diluted	**1,005,122**	1,006,147	1,005,310

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 and the S&P/TSX Capped Energy 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, 2019)

Outstanding Shares

The number of common shares outstanding at December 31, 2019 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 and Special Meeting of Shareholders will be held at 10:30 a.m. on Wednesday, April 29, 2020, in the Patricia A. Whelan Performance Hall at Calgary New Central Library, 800 - 3rd Street S.E., Calgary, Alberta, Canada.

Additional Publications

The following publications are available on Husky's 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

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