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"

Robert J. Peabody

President & Chief Executive Officer

"Jeffrey R. Hart"

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.

/s/ KPMG LLP
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"

Robert J. Peabody
Director

"William Shurniak"

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)

	Years ended December 31,	
(millions of Canadian dollars)	**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

($ millions)	Upstream					
	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%).

		Canadian $ Amount		U.S. $ Denominated	
Long-term Debt ***($ 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	**2019**		2018	
($ millions)	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	**2019**		2018	
($ millions)	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

	Integrated Corridor									
($ millions)	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