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, 2015. 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 Canadian Auditing Standards and 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.

"Asim Ghosh"

Asim Ghosh

President & Chief Executive Officer

"Jonathan M. McKenzie"

Jonathan M. McKenzie

Chief Financial Officer

Calgary, Canada

February 25, 2016

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated financial statements of Husky Energy Inc., which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014, the consolidated statements of income (loss), comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Husky Energy Inc. as at December 31, 2015 and December 31, 2014, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

"KPMG LLP"

KPMG LLP

Chartered Professional Accountants

February 25, 2016

Calgary, Canada

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2015**	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents *(note 4)*	**70**	1,267
Accounts receivable *(notes 5, 24)*	**1,014**	1,324
Income taxes receivable	**312**	353
Inventories *(note 6)*	**1,247**	1,385
Prepaid expenses	**271**	166
	2,914	4,495
Restricted cash *(note 7, 16)*	**121**	–
Exploration and evaluation assets *(note 8)*	**1,091**	1,149
Property, plant and equipment, net *(note 9)*	**27,634**	31,987
Goodwill *(note 10)*	**700**	746
Investment in joint ventures *(note 11)*	**359**	237
Long-term income tax receivable	**109**	109
Other assets	**128**	125
Total Assets	**33,056**	38,848
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 13)*	**2,527**	2,989
Short-term debt *(note 14)*	**720**	895
Long-term debt due within one year *(note 14)*	**277**	300
Contribution payable due within one year *(note 11)*	**210**	1,528
Asset retirement obligations *(note 16)*	**102**	97
	3,836	5,809
Long-term debt *(note 14)*	**5,759**	4,097
Other long-term liabilities *(note 15)*	**743**	585
Contribution payable *(note 11)*	**138**	–
Asset retirement obligations *(note 16)*	**2,882**	2,968
Deferred tax liabilities *(note 17)*	**3,112**	4,814
Commitments and contingencies *(note 22)*		
Total Liabilities	**16,470**	18,273
Shareholders' equity		
Common shares *(note 18)*	**7,000**	6,986
Preferred shares *(note 18)*	**874**	534
Retained earnings	**7,589**	12,666
Other reserves	**1,123**	389
Total Shareholders' Equity	**16,586**	20,575
Total Liabilities and Shareholders' Equity	**33,056**	38,848

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

On behalf of the Board:

"Asim Ghosh"

Asim Ghosh
Director

"William Shurniak"

William Shurniak
Director

Consolidated Statements of Income (Loss)

(millions of Canadian dollars, except share data)	Year ended December 31, **2015**	2014
Gross revenues	**16,763**	25,052
Royalties	**(432)**	(1,030)
Marketing and other	**38**	70
Revenues, net of royalties	**16,369**	24,092
Expenses		
Purchases of crude oil and products	**9,397**	14,409
Production, operating and transportation expenses *(note 27)*	**2,994**	3,119
Selling, general and administrative expenses *(note 27)*	**342**	462
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**8,644**	4,010
Exploration and evaluation expenses *(note 8)*	**447**	214
Other – net *(note 9)*	**(309)**	(56)
	21,515	22,158
Earnings (loss) from operating activities	**(5,146)**	1,934
Share of equity investment *(note 11)*	**(5)**	(6)
Financial items *(note 20)*		
Net foreign exchange gains	**43**	81
Finance income	**35**	8
Finance expenses	**(298)**	(233)
	(220)	(144)
Earnings (loss) before income taxes	**(5,371)**	1,784
Provisions for (recovery of) income taxes *(note 17)*		
Current	**306**	717
Deferred	**(1,827)**	(191)
	(1,521)	526
Net earnings (loss)	**(3,850)**	1,258
Earnings (loss) per share *(note 18)*		
Basic	**(3.95)**	1.26
Diluted	**(4.01)**	1.20
Weighted average number of common shares outstanding *(note 18)*		
Basic *(millions)*	**984.1**	983.6
Diluted *(millions)*	**984.1**	985.3

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

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars)	Year ended December 31, 2015	2014
Net earnings (loss)	**(3,850)**	1,258
Other comprehensive income (loss)		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans, net of tax *(note 19)*	**(10)**	(14)
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedges *(note 24)*	**(3)**	(14)
Exchange differences on translation of foreign operations	**1,324**	465
Hedge of net investment *(note 24)*	**(587)**	(260)
Other comprehensive income	**724**	177
Comprehensive income (loss)	**(3,126)**	1,435

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					
				Other Reserves		
(millions of Canadian dollars)	Common Shares	Preferred Shares	Retained Earnings	Foreign Currency Translation	Hedging	Total Shareholders' Equity
Balance as at December 31, 2013	6,974	291	12,615	161	37	20,078
Net earnings	–	–	1,258	–	–	1,258
Other comprehensive income (loss)						
Remeasurements of pension plans (net of tax recovery of $4 million) *(note 17, 19)*	–	–	(14)	–	–	(14)
Derivatives designated as cash flow hedges (net of tax recovery of $5 million) *(note 17, 24)*	–	–	–	–	(14)	(14)
Exchange differences on translation of foreign operations (net of tax of $109 million) *(note 17)*	–	–	–	465	–	465
Hedge of net investment (net of tax recovery of $39 million) *(note 17, 24)*	–	–	–	(260)	–	(260)
Total comprehensive income (loss)	–	–	1,244	205	(14)	1,435
Transactions with owners recognized directly in equity:						
Preferred shares issuance *(note 18)*	–	250	–	–	–	250
Share issue costs *(note 18)*	–	(7)	–	–	–	(7)
Stock dividends paid *(note 18)*	11	–	–	–	–	11
Stock options exercised *(note 18)*	1	–	–	–	–	1
Dividends declared on common shares *(note 18)*	–	–	(1,180)	–	–	(1,180)
Dividends declared on preferred shares *(note 18)*	–	–	(13)	–	–	(13)
Balance as at December 31, 2014	6,986	534	12,666	366	23	20,575
Net loss	–	–	**(3,850)**	–	–	**(3,850)**
Other comprehensive income (loss)						
Remeasurements of pension plans (net of tax recovery of $3 million) *(note 17, 19)*	–	–	**(10)**	–	–	**(10)**
Derivatives designated as cash flow hedges (net of tax recovery of $1 million) *(note 17, 24)*	–	–	–	–	**(3)**	**(3)**
Exchange differences on translation of foreign operations (net of tax of $215 million) *(note 17)*	–	–	–	**1,324**	–	**1,324**
Hedge of net investment (net of tax recovery of $92 million) *(note 17, 24)*	–	–	–	**(587)**	–	**(587)**
Total comprehensive income (loss)	–	–	**(3,860)**	**737**	**(3)**	**(3,126)**
Transactions with owners recognized directly in equity:						
Preferred shares issuance *(note 18)*	–	**350**	–	–	–	**350**
Share issue costs *(note 18)*	–	**(10)**	–	–	–	**(10)**
Stock dividends paid *(note 18)*	**14**	–	–	–	–	**14**
Dividends declared on common shares *(note 18)*	–	–	**(1,181)**	–	–	**(1,181)**
Dividends declared on preferred shares *(note 18)*	–	–	**(36)**	–	–	**(36)**
Balance as at December 31, 2015	**7,000**	**874**	**7,589**	**1,103**	**20**	**16,586**

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

Consolidated Statements of Cash Flows

(millions of Canadian dollars)	Year ended December 31, 2015	2014
Operating activities		
Net earnings (loss)	**(3,850)**	1,258
Items not affecting cash:		
Accretion *(note 20)*	**121**	134
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**8,644**	4,010
Inventory write-down to net realizable value *(note 6)*	**22**	211
Exploration and evaluation expenses *(note 8)*	**242**	6
Deferred income taxes *(note 17)*	**(1,827)**	(191)
Foreign exchange	**27**	71
Stock-based compensation *(note 18)*	**(39)**	(17)
Gain on sale of assets	**(16)**	(36)
Other	**5**	89
Settlement of asset retirement obligations *(note 16)*	**(98)**	(167)
Deferred revenue	**102**	–
Income taxes paid	**(227)**	(661)
Interest received	**3**	7
Change in non-cash working capital *(note 21)*	**651**	871
Cash flow – operating activities	**3,760**	5,585
Financing activities		
Long-term debt issuance *(note 14)*	**9,449**	829
Long-term debt repayment *(note 14)*	**(8,500)**	(814)
Settlement of interest rate swaps	**–**	33
Short-term debt *(note 14)*	**(175)**	895
Debt issue costs	**(7)**	–
Proceeds from preferred share issuance, net of share issue costs *(note 18)*	**340**	243
Proceeds from exercise of stock options *(note 18)*	**–**	1
Dividends on common shares *(note 18)*	**(1,167)**	(1,169)
Dividends on preferred shares *(note 18)*	**(36)**	(13)
Interest paid	**(323)**	(284)
Contribution receivable receipt *(note 11)*	**–**	143
Other	**30**	97
Change in non-cash working capital *(note 21)*	**179**	33
Cash flow – financing activities	**(210)**	(6)
Investing activities		
Capital expenditures	**(3,005)**	(5,023)
Proceeds from asset sales	**122**	66
Contribution payable payment *(note 11)*	**(1,363)**	(106)
Other	**(239)**	(27)
Change in non-cash working capital *(note 21)*	**(332)**	(333)
Cash flow – investing activities	**(4,817)**	(5,423)
Increase (decrease) in cash and cash equivalents	**(1,267)**	156
Effect of exchange rates on cash and cash equivalents	**70**	14
Cash and cash equivalents at beginning of year	**1,267**	1,097
Cash and cash equivalents at end of year	**70**	1,267

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 3, Cumulative Redeemable Preferred Shares, Series 5 and Cumulative Redeemable Preferred Shares, Series 7 are listed under the symbols, "HSE.PR.A","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 includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore China and offshore Indonesia.

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading) in Canada, refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. Refining and Marketing). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and therefore, were 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		Total	
Year ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Gross revenues	**5,374**	8,634	**1,264**	2,202	**6,638**	10,836
Royalties	**(432)**	(1,030)	–	–	**(432)**	(1,030)
Marketing and other	–	–	**38**	70	**38**	70
Revenues, net of royalties	**4,942**	7,604	**1,302**	2,272	**6,244**	9,876
Expenses						
Purchases of crude oil and products	**41**	96	**1,123**	2,056	**1,164**	2,152
Production, operating and transportation expenses	**2,076**	2,172	**37**	32	**2,113**	2,204
Selling, general and administrative expenses	**237**	253	**7**	8	**244**	261
Depletion, depreciation, amortization and impairment	**7,993**	3,434	**25**	25	**8,018**	3,459
Exploration and evaluation expenses	**447**	214	–	–	**447**	214
Other – net	**(51)**	(60)	**(5)**	(2)	**(56)**	(62)
Earnings (loss) from operating activities	**(5,801)**	1,495	**115**	153	**(5,686)**	1,648
Share of equity investment	**(5)**	(6)	–	–	**(5)**	(6)
Financial items						
Net foreign exchange gains	–	–	–	–	–	–
Finance income	**3**	(1)	–	–	**3**	(1)
Finance expenses	**(142)**	(151)	–	–	**(142)**	(151)
Earnings (loss) before income taxes	**(5,945)**	1,337	**115**	153	**(5,830)**	1,490
Provisions for (recovery of) income taxes						
Current	**(41)**	386	**222**	99	**181**	485
Deferred	**(1,566)**	(41)	**(191)**	(60)	**(1,757)**	(101)
	(1,607)	345	**31**	39	**(1,576)**	384
Net earnings (loss)	**(4,338)**	992	**84**	114	**(4,254)**	1,106
Intersegment revenues	**1,081**	2,229	–	–	**1,081**	2,229
Other non-cash items						
Gain (loss) on sale of assets	**17**	39	–	–	**17**	39

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*
(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices. Segment results include transactions between business segments.*

Downstream										Corporate and Eliminations[2]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total							
2015	2014	**2015**	2014	**2015**	2014	**2015**	2014			**2015**	2014	**2015**	2014
1,319	2,212	**2,886**	4,020	**7,345**	10,663	**11,550**	16,895			**(1,425)**	(2,679)	**16,763**	25,052
–	–	**–**	–	**–**	–	**–**	–			**–**	–	**(432)**	(1,030)
–	–	**–**	–	**–**	–	**–**	–			**–**	–	**38**	70
1,319	2,212	**2,886**	4,020	**7,345**	10,663	**11,550**	16,895			**(1,425)**	(2,679)	**16,369**	24,092
922	1,676	**2,281**	3,319	**6,455**	9,941	**9,658**	14,936			**(1,425)**	(2,679)	**9,397**	14,409
169	180	**238**	263	**474**	472	**881**	915			**–**	–	**2,994**	3,119
4	9	**31**	44	**10**	9	**45**	62			**53**	139	**342**	462
106	108	**103**	102	**333**	268	**542**	478			**84**	73	**8,644**	4,010
–	–	**–**	–	**–**	–	**–**	–			**–**	–	**447**	214
(11)	11	**(4)**	–	**(236)**	–	**(251)**	11			**(2)**	(5)	**(309)**	(56)
129	228	**237**	292	**309**	(27)	**675**	493			**(135)**	(207)	**(5,146)**	1,934
–	–	**–**	–	**–**	–	**–**	–			**–**	–	**(5)**	(6)
–	–	**–**	–	**–**	–	**–**	–			**43**	81	**43**	81
–	–	**–**	–	**–**	–	**–**	–			**32**	9	**35**	8
(1)	(1)	**(6)**	(5)	**(3)**	(3)	**(10)**	(9)			**(146)**	(73)	**(298)**	(233)
128	227	**231**	287	**306**	(30)	**665**	484			**(206)**	(190)	**(5,371)**	1,784
(17)	47	**6**	80	**15**	1	**4**	128			**121**	104	**306**	717
52	12	**55**	(7)	**(106)**	(12)	**1**	(7)			**(71)**	(83)	**(1,827)**	(191)
35	59	**61**	73	**(91)**	(11)	**5**	121			**50**	21	**(1,521)**	526
93	168	**170**	214	**397**	(19)	**660**	363			**(256)**	(211)	**(3,850)**	1,258
164	249	**180**	201	**–**	–	**344**	450			**–**	–	**1,425**	2,679
–	–	**5**	1	**–**	(4)	**5**	(3)			**–**	–	**22**	36

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Expenditures on exploration and evaluation assets[2][3]	**205**	326	–	–	**205**	326
Expenditures on property, plant and equipment[2][3]	**2,064**	3,863	**168**	211	**2,232**	4,074
Investment in joint ventures	**37**	–	–	–	**37**	–
As at December 31,						
Exploration and evaluation assets	**1,091**	1,149	–	–	**1,091**	1,149
Developing and producing assets at cost	**50,380**	47,969	–	–	**50,380**	47,969
Accumulated depletion, depreciation, amortization and impairment	**(31,298)**	(23,686)	–	–	**(31,298)**	(23,686)
Other property, plant and equipment at cost	–	48	**1,467**	1,250	**1,467**	1,298
Accumulated depletion, depreciation and amortization	–	(34)	**(576)**	(495)	**(576)**	(529)
Total exploration and evaluation assets and property, plant and equipment, net	**20,173**	25,446	**891**	755	**21,064**	26,201
Total assets	**21,103**	26,035	**1,699**	1,969	**22,802**	28,004

(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 assets acquired through acquisitions.*
(3) *Capital expenditures in 2015 were revised to exclude capital expenditures incurred by the Husky-CNOOC Madura Ltd. joint venture which are classified as other investing activities on the Company's Consolidated Statements of Cash Flows.*

Geographical Financial Information

($ millions)	Canada		United States	
Year ended December 31,	**2015**	2014	**2015**	2014
Gross revenues[1]	**6,810**	12,484	**8,638**	11,725
Royalties	**(361)**	(964)	–	–
Marketing and other	**38**	70	–	–
Revenue, net of royalties	**6,487**	11,590	**8,638**	11,725
As at December 31,				
Restricted Cash	–	–	–	–
Exploration and evaluation assets	**690**	818	–	–
Property, plant and equipment, net	**19,005**	24,201	**5,139**	4,233
Goodwill	–	160	**700**	586
Investment in joint ventures	–	–	–	–
Long-term income tax receivable	**109**	109	–	–
Other assets	**83**	84	**23**	19
Total non-current assets	**19,887**	25,372	**5,862**	4,838

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

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2015	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014
–	–	–	–	–	–	–	–	–	–	205	326
46	50	30	86	425	374	501	510	67	113	2,800	4,697
–	–	–	–	–	–	–	–	–	–	37	–
–	–	–	–	–	–	–	–	–	–	1,091	1,149
–	–	–	–	–	–	–	–	–	–	50,380	47,969
–	–	–	–	–	–	–	–	–	–	(31,298)	(23,686)
2,313	2,274	2,438	2,433	7,435	5,874	12,186	10,581	957	889	14,610	12,768
(1,260)	(1,154)	(1,245)	(1,144)	(2,296)	(1,641)	(4,801)	(3,939)	(681)	(596)	(6,058)	(5,064)
1,053	1,120	1,193	1,289	5,139	4,233	7,385	6,642	276	293	28,725	33,136
1,141	1,243	1,448	1,676	6,784	5,788	9,373	8,707	881	2,137	33,056	38,848

China		Other International		Total	
2015	2014	2015	2014	2015	2014
1,315	843	–	–	16,763	25,052
(71)	(66)	–	–	(432)	(1,030)
–	–	–	–	38	70
1,244	777	–	–	16,369	24,092
121	–	–	–	121	–
394	327	7	4	1,091	1,149
3,490	3,454	–	99	27,634	31,987
–	–	–	–	700	746
–	–	359	237	359	237
–	–	–	–	109	109
–	–	22	22	128	125
4,005	3,781	388	362	30,142	34,353

Note 2 Basis of Presentation

a) Basis of Measurement and Statement of Compliance

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

These consolidated financial statements were approved and signed by the Chair of the Audit Committee and the Chief Executive Officer on February 25, 2016 having been duly authorized to do so by the Board of Directors.

Certain prior years' amounts have been recast 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. Substantially all of the Company's Upstream activities are conducted jointly with third parties, and accordingly, the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows from these activities. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

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, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes 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 successful efforts and impairment assessments, the determination of cash generating units ("CGUs"), the determination of a joint arrangement and the designation of the Company's functional currency.

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 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 and transportation. 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. Any changes in commodity inventory fair value are included as gains or losses in marketing and other in the consolidated statements of income, during the period of change. Previous inventory impairment provisions are reversed when there is a change in the condition that caused the impairment. Unrealized intersegment net earnings on inventory sales are eliminated.

c) Precious Metals

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

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

i) Cost

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

The appropriate 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 both judgment 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.

ii) Exploration and evaluation costs

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 uses judgment to determine 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, including unsuccessful development or delineation wells, are capitalized as oil and gas properties. Costs incurred to operate and maintain wells and equipment to lift oil and gas to the surface are expensed as production and operating expenses.

iv) Other property, plant and equipment

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

v) Depletion, depreciation and amortization

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

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

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

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

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

Any gain or loss arising on disposal of exploration and evaluation assets or property, plant and equipment is included in other – net in the consolidated statements of income in the period of disposal.

vi) Finance Leases

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

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

e) Joint Arrangements

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

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

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

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

f) Investments in Associates

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

g) Business Combinations

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

h) Goodwill

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

i) Impairment of Non-Financial Assets

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

Determining whether there are any indications of impairment requires significant judgment of external factors, such as an extended decrease in prices or margins for oil and gas commodities or products, a significant decline in an asset's market value, a significant downward revision of estimated volumes, an upward revision of future development costs, a decline in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an adverse impact on the Company's CGUs. If any indication of impairment exists, 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.

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

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

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

Impairment losses recognized for other assets in prior years are assessed at the end of each reporting period for any indications that the impairment condition 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, removing and disposing of 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. In the case of closed sites, changes to estimated costs are recognized immediately in net earnings. Changes to the amount of capitalized costs will result in an adjustment to future depletion, depreciation and amortization, and to finance expenses.

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

k) Legal and Other Contingent Matters

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

l) Share Capital

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

m) Financial Instruments

Financial instruments are any contracts that give rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are initially recognized at fair value, and subsequently measured based on classification in one of the following categories: loans and receivables, held to maturity investments, other financial liabilities, fair value through profit or loss (“FVTPL”) or available-for-sale ("AFS") financial assets.

Financial instruments classified as FVTPL or AFS are measured at fair value at each reporting date; any transaction costs associated with these types of instruments are expensed as incurred. Unrealized gains and losses on AFS financial assets are recognized in OCI (see policy note o) and transferred to net earnings when the asset is derecognized. Unrealized gains and losses on FVTPL financial instruments related to trading activities are recognized in marketing and other in the consolidated statements of income, and unrealized gains and losses on all other FVTPL financial instruments are recognized in other – net.

Financial instruments classified as loans or receivables, held to maturity investments and other financial liabilities are initially measured at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs that are directly attributable to the acquisition or issue of a financial instrument measured at amortized cost are added to the fair value initially recognized.

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.

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. 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, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

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

ii) Embedded Derivatives

Derivatives embedded in a host contract 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 other freestanding derivatives. Embedded derivatives are measured at fair value with gains and losses recognized in net earnings.

iii) Hedging Activities

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

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

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

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

o) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI is comprised of the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge, the unrealized gains and losses on AFS financial assets, 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 for loans and receivables.

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. A revaluation with respect to an AFS financial asset is calculated by reference to its fair value and any amounts in OCI are transferred to net earnings.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

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

q) Pensions and Other Post-employment Benefits

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

The 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.

Mortality rates are based on the latest available standard mortality tables for the individual countries concerned. The assumptions for each country are reviewed each year and are adjusted where necessary to reflect changes in fund experience and actuarial recommendations. 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 taxes are recognized in net earnings, except when they relate to equity, which includes OCI, and are recognized directly 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 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 from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenues associated with the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recognized when the title passes to the customer. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

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, revenue is deferred and recognized only when the product is delivered or the make-up product can no longer be taken. If no such option exists within the contractual terms, revenue is recognized when the take-or-pay penalty is triggered.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Crude oil and natural gas sold below or above the Company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at cost with a corresponding decrease to production and operating expense, while overlifts are recorded as a payable at fair value with a corresponding increase to production and operating expense.

Physical exchanges of inventory 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.

Finance income is recognized as the interest accrues using the effective interest rate, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset.

u) Foreign Currency

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

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

v) Share-based Payments

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

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

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

w) Earnings per Share

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

The number of diluted common shares outstanding is calculated using the treasury stock method, which assumes that any proceeds received from in-the-money stock options would be used to buy back common shares at the average market price for the period.

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

x) Government Grants

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

y) Recent Accounting Standards

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

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. Early adoption is permitted. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

Leases

In January 2016, the IASB issued IFRS 16 Leases. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16. The Company is currently evaluating the impact of adopting IFRS 16 on the consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9, "Financial Instruments" to replace IAS 39 which provides a logical model for classification and measurement, a single, forward-looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The standard is effective for the Company for annual periods beginning on January 1, 2018, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2018. The Company is currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.

z) Change in Accounting Policy

The Company has applied the following standards and amendments for the first time for the annual reporting period commencing January 1, 2015:

- Annual Improvements to IFRS - 2010-2012 Cycle and 2011-2013 Cycle
- Defined Benefit Plans: Employee Contributions - Amendments to IAS 19

The adoption of these amendments did not have any impact on the annual consolidated financial statements. The nature and the impact of each new standard or amendment is described below:

IFRS 8 Operating Segments

The amendments are applied retrospectively and clarify that an entity must disclose the judgments made by management in applying the aggregation criteria in paragraph 12 of IFRS 8, including a brief description of operating segments that have been aggregated and the economic characteristics used to assess whether the segments are 'similar'. The reconciliation of segment assets to total assets is only required to be disclosed if the reconciliation is reported to the chief operating decision maker, similar to the required disclosure for segment liabilities. The adoption of this amended standard has no material impact on the Company's consolidated financial statements.

IFRS 2 Share-based Payment

This improvement is applied prospectively and clarifies various issues relating to the definitions of performance and service conditions which are vesting conditions, including:

- A performance condition must contain a service condition;
- A performance target must be met while the counterparty is rendering service;
- A performance target may relate to the operations or activities of an entity, or to those of another entity in the same group;
- A performance condition may be a market or non-market condition.

The adoption of this amended standard has no impact on the Company's consolidated financial statements.

IFRS 3 Business Combinations

The amendment is applied prospectively and clarifies that all contingent consideration arrangements classified as liabilities (or assets) arising from a business combination should be subsequently measured at fair value through profit or loss whether or not they fall within the scope of IFRS 9 (or IAS 39, as applicable). The adoption of this amended standard has no impact on the Company's consolidated financial statements.

Note 4 Cash and Cash Equivalents

Cash and cash equivalents at December 31, 2015 included $68 million of cash (December 31, 2014 – $188 million) and $2 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2014 – $1,079 million).

Note 5 Accounts Receivable

Accounts Receivable

($ millions)	December 31, 2015	December 31, 2014
Trade receivables	962	1,282
Allowance for doubtful accounts	(31)	(29)
Derivatives due within one year	59	53
Other	24	18
End of year	1,014	1,324

Note 6 Inventories

Inventories

($ millions)	December 31, 2015	December 31, 2014
Crude oil, natural gas and sulphur	536	419
Refined petroleum products	257	522
Trading inventories measured at fair value less costs to sell	257	286
Materials, supplies and other	197	158
End of year	1,247	1,385

Impairment of inventory to net realizable value for the year ended December 31, 2015 was $22 million (December 31, 2014 – $211 million), as a result of declining market benchmark prices. During 2015, there were no inventory impairment reversals (2014 – nil).

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 the Asia Pacific Region. As at December 31, 2015, the Company had deposited funds of $121 million (2014 - nil) which are classified as non-current and included in restricted cash.

Note 8 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	**2015**	2014
Beginning of year	**1,149**	1,144
Additions	**227**	341
Transfers to oil and gas properties *(note 9)*	**(97)**	(352)
Expensed exploration expenditures previously capitalized	**(242)**	(6)
Exchange adjustments	**54**	22
End of year	**1,091**	1,149

During 2015, $229 million of the $242 million in total expensed exploration expenditures previously capitalized was related to exploration assets within the Western Canada CGUs in the Upstream Exploration and Production Segment which were written off as a result of management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices.

The following exploration and evaluation expenses for the years ended December 31, 2015 and 2014 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)	**2015**	2014
Seismic, geological and geophysical	**103**	111
Expensed drilling	**297**	45
Expensed land	**47**	58
	447	214

During 2015, $48 million of the $297 million in total expensed drilling was recorded as an exploration and evaluation expense due to unfulfilled work commitment penalties in Western Canada resulting from management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices.

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, 2013	43,081	1,080	2,221	5,676	2,450	54,508
Additions	4,274	216	50	413	163	5,116
Acquisitions	123	–	–	–	–	123
Transfers from exploration and evaluation *(note 8)*	352	–	–	–	–	352
Intersegment transfers	(3)	2	–	1	–	–
Changes in asset retirement obligations	128	(2)	3	15	23	167
Disposals and derecognition	(281)	–	–	(13)	(4)	(298)
Exchange adjustments	300	–	–	469	–	769
December 31, 2014	47,974	1,296	2,274	6,561	2,632	60,737
Additions	**2,128**	**173**	**46**	**452**	**76**	**2,875**
Acquisitions	**57**	–	–	–	–	**57**
Transfers from exploration and evaluation *(note 8)*	**97**	–	–	–	–	**97**
Intersegment transfers	**6**	**(6)**	–	–	–	–
Changes in asset retirement obligations	**(107)**	–	**(7)**	**(5)**	**(18)**	**(137)**
Disposals and derecognition	**(487)**	–	–	**(24)**	**(4)**	**(515)**
Exchange adjustments	**720**	**2**	–	**1,152**	**2**	**1,876**
December 31, 2015	**50,388**	**1,465**	**2,313**	**8,136**	**2,688**	**64,990**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2013	(20,408)	(479)	(1,046)	(1,574)	(1,251)	(24,758)
Depletion, depreciation, amortization and impairment[(1)]	(3,400)	(47)	(108)	(288)	(145)	(3,988)
Intersegment transfers	2	(1)	–	(1)	–	–
Disposals and derecognition	176	–	–	10	2	188
Exchange adjustments	(57)	–	–	(135)	–	(192)
December 31, 2014	(23,687)	(527)	(1,154)	(1,988)	(1,394)	(28,750)
Depletion, depreciation, amortization and impairment[(1)]	**(7,811)**	**(48)**	**(106)**	**(365)**	**(154)**	**(8,484)**
Intersegment transfers	**(2)**	**2**	–	–	–	–
Disposals and derecognition	**370**	–	–	**18**	**2**	**390**
Exchange adjustments	**(170)**	**(1)**	–	**(341)**	–	**(512)**
December 31, 2015	**(31,300)**	**(574)**	**(1,260)**	**(2,676)**	**(1,546)**	**(37,356)**
Net book value						
December 31, 2014	24,287	769	1,120	4,573	1,238	31,987
December 31, 2015	**19,088**	**891**	**1,053**	**5,460**	**1,142**	**27,634**

[(1)] *Depletion, depreciation, amortization and impairment for the year ended December 31, 2015 does not include an exchange adjustment of nil (2014 – $22 million).*

Included in depletion, depreciation, amortization and impairment expense for the year ended December 31, 2015 is a pre-tax impairment charge of $5,021 million (2014 - $838 million) on crude oil and natural gas assets located in Western Canada in the Upstream Exploration and Production Segment. The impairment charge, reflected in the third quarter of 2015 and attributed to Western Canada production CGUs, was the result of sustained declines in forecasted short and long-term crude oil and natural gas prices and management's decision to reduce capital investments in those CGUs. The Company identified a further impairment trigger in the fourth quarter of 2015 due to changes in reserve estimates using finalized annual reserve information, which resulted in adjustments to individual CGUs only with no further impairment recorded on a consolidated basis. The recoverable amount of the impaired CGUs was estimated based on the value-in-use methodology using estimated discounted cash flows based on proved plus probable reserves and where applicable economically recoverable resources associated with interests in certain Husky properties and a pre-tax discount rate of 8 percent (2014 - 8 percent).

The following table summarizes the impairments for each CGU:

CGU ($ millions)	Impairment recorded
British Columbia & Alberta Plains	383
Foothills	1,130
Ram River	564
Northern Alberta	474
Rainbow	1,338
Red Deer	170
Hussar Halkirk	106
Northern	119
Provost East	124
Provost West	101
Northern Saskatchewan	22
Southern Alberta	249
Southern Saskatchewan	241
Total	**5,021**

The recoverable amount of the various Western Canada CGUs was $3,038 million as at December 31, 2015. The recoverable amount is sensitive to commodity price, discount rate, production volumes, operating costs and future capital expenditures. Refer to Note 10 for sensitivity analysis. Commodity prices are based on market indicators at the end of the period. Management's external 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)
2016	50.00	50.00	53.33	3.00	0.750
2017	55.00	60.00	64.94	3.06	0.770
2018	60.00	70.00	74.88	3.12	0.800
2019	65.00	71.40	76.37	3.18	0.800
2020	70.00	72.83	77.90	3.25	0.800
2021	71.40	74.28	79.46	3.31	0.800
2022(1)	72.83	75.77	81.05	3.38	0.800

(1) Prices are escalated at 2 percent thereafter.

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 and to determine the pre-tax rate. Production volumes, operating costs and future capital expenditures are based on management's best estimates of future costs included in the long range plan approved by the Board of Directors.

Depletion, depreciation, amortization and impairment expense for the twelve months ended December 31, 2015 also included a $46 million derecognition reflected in the second quarter of 2015 for damage caused by a fire at the Lima Refinery in the Company's Downstream U.S. Refining and Marketing business and a $46 million derecognition in the third quarter of 2015 related to the cancellation of the West Mira drilling rig contract. In addition, the Company accrued insurance recoveries for business interruption and property damage associated with the fire of $235 million for the year ended December 31, 2015 which is included in other-net in the consolidated statements of income (loss).

Costs of property, plant and equipment, including major development projects, excluded from costs subject to depletion, depreciation and amortization as at December 31, 2015 were $3.0 billion (December 31, 2014 – $5.7 billion) including undeveloped land assets of $68 million as at December 31, 2015 (December 31, 2014 – $115 million).

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

Assets Under Finance Lease ($ millions)	Refining	Oil and Gas Properties	Total
December 31, 2014	27	256	283
December 31, 2015	**26**	**255**	**281**

Note 10 Goodwill

Goodwill

($ millions)	December 31, 2015	December 31, 2014
Beginning of year	**746**	698
Exchange adjustments	**114**	48
Impairment	**(160)**	–
End of year	**700**	746

For the purpose of impairment testing, goodwill is allocated to the CGUs to which it relates. The carrying amount of goodwill has been allocated as follows:

Carrying amount of goodwill as at:

($ millions)	December 31, 2015	December 31, 2014
Upstream (Western Canada)	**–**	160
Downstream (Lima Refinery)	**700**	586
End of year	**700**	746

Upstream (Western Canada)

The Company performed a goodwill impairment test at September 30, 2015. The Company determined that the carrying amount of the Western Canada CGUs in the Upstream Exploration and Production Segment exceeded its recoverable amount and the amount of impairment was attributable to goodwill and crude oil and natural gas assets located in Western Canada. A pre-tax goodwill impairment charge of $160 million was included in depletion, depreciation, amortization and impairment expense. The recoverable amount of the Western Canada CGUs was $3,038 million as at December 31, 2015 and was estimated based on value-in-use methodology using estimated discounted cash flows based on proved plus probable reserves and where applicable economically recoverable resources associated with interests in certain Husky properties and a pre-tax discount rate of 8 percent (2014 - 8 percent).

The recoverable amount is sensitive to commodity price, discount rate, production volumes, 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 the forward price curve and external firms on an annual basis or whenever a trigger exists. The price deck used is consistent with that used in determining the recoverable amount of property, plant and equipment. 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 and to determine the pre-tax rate. Production volumes, operating costs and future capital expenditures are based on management's best estimates of future costs per 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 following impact on the Western Canada 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 Goodwill	–	–	–	–
Impairment of PP&E - Increase (Decrease)	156	(198)	(519)	560

Downstream (Lima Refinery)

For impairment testing purposes, the recoverable amount of the Lima Refinery CGU was estimated using value-in-use methodology based on cash flows expected over a 40-year period and discounted using a pre-tax discount rate of 8 percent (2014 - 8 percent).

The value-in-use calculation for the Lima Refinery CGU is sensitive to changes in discount rate, forecasted crack spreads and growth rate. 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 refinery. Forecasted crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel. The WTI price deck used is consistent with that used in determining the recoverable amount of property, plant and equipment.

Cash flow projections for the initial five-year period are based on long range plan future cash flows and inflated by a 2 percent long-term growth rate for the remaining 35-year period. The inflation rate was based upon an average expected inflation rate for the U.S. of 2 percent (2014 - 2 percent). As at December 31, 2015, the recoverable amount exceeded the carrying amount and no impairment was identified.

With regard to the assessment of value in use of the Lima Refinery CGU, management believed that there are no reasonably possible changes in any of the above key assumptions that would cause the carrying value of the CGU to materially exceed its recoverable amount.

Note 11 Joint Arrangements

Joint Operations

BP-Husky Refining LLC

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

The Company's proportionate share of the contribution payable included in the consolidated balance sheets is as follows:

Contribution Payable

($ millions)	**December 31, 2015**	December 31, 2014
Beginning of year	**1,528**	1,421
Accretion *(note 20)*	**16**	85
Paid	**(1,363)**	(106)
Foreign exchange	**167**	128
End of year	**348**	1,528
Expected to be incurred within 1 year	**210**	1,528
Expected to be incurred beyond 1 year	**138**	–

The Company amended the terms of payment of the Company's contribution payable with BP-Husky Refining LLC in the first quarter of 2015. In accordance with the amendment, U.S. $1 billion of the net contribution payable was paid on February 2, 2015. Subsequent to the payment, BP-Husky Refining LLC distributed U.S. $1 billion to each of the joint arrangement partners which resulted in the creation of a deferred tax asset and deferred tax recovery of $203 million. As a result of prepayment, the accretion rate was reduced from 6 percent to 2.5 percent for the future term of the agreement and the remaining maturity date was extended to December 31, 2017. The remaining net contribution payable amount of approximately U.S. $251 million (CDN $348 million) will be paid by way of funding all capital contributions of the BP-Husky Refining LLC joint operation with the current and long-term portions reflecting the timing of future expected capital expenditures as at December 31, 2015.

Summarized below is the Company's proportionate share of operating results and financial position in the BP-Husky Refining LLC joint operation that have been included in the consolidated statements of income (loss) and the consolidated balance sheets in U.S. Refining and Marketing in the Downstream segment:

Results of Operations

($ millions)	2015	2014
Revenues	1,959	2,673
Expenses	(1,826)	(2,847)
Proportionate share of net earnings	133	(174)

Balance Sheets

($ millions)	December 31, 2015	December 31, 2014
Current assets	469	379
Non-current assets	2,405	2,073
Current liabilities	(367)	(336)
Non-current liabilities	(681)	(630)
Proportionate share of net assets	1,826	1,486

Sunrise Oil Sands Partnership

The Company holds a 50 percent interest in the Sunrise Oil Sands Partnership, which is engaged in operating an oil sands project in Northern Alberta. On March 31, 2008, the Company completed a transaction with BP whereby the Company contributed Sunrise oil sands assets with a fair value of U.S. $2.5 billion and BP contributed U.S. $250 million in cash and a contribution receivable of U.S. $2.25 billion which was received in full in the year ended December 31, 2014. The contribution receivable accreted at a rate of 6 percent per annum up to the receipt of the final balance in 2014.

Summarized below is the Company's proportionate share of operating results and financial position in the Sunrise Oil Sands Partnership that have been included in the consolidated statements of income (loss) and the consolidated balance sheets in Exploration and Production in the Upstream segment:

Results of Operations

($ millions)	2015	2014
Revenues	17	–
Expenses	(160)	(24)
Financial items	(28)	(16)
Proportionate share of net earnings	(171)	(40)

Balance Sheets

($ millions)	December 31, 2015	December 31, 2014
Current assets	28	2
Non-current assets	3,161	3,124
Current liabilities	(104)	(74)
Non-current liabilities	(248)	(258)
Proportionate share of net assets	2,837	2,794

Atlantic Region Joint Operations

The Company holds interests in the White Rose oil field, with a 72.5 percent interest in the core field and a 68.875 percent interest in the satellite fields. The Company also holds 35 percent interests in two exploration licenses and two significant discovery licenses in the Flemish Pass Basin related to the Bay Du Nord, Harpoon and Mizzen discoveries. Both areas are located off the coast of Newfoundland and Labrador and are a part of Husky's offshore East Coast exploration and development program. The Company's proportionate share of operating results and financial position in the White Rose oil field and Flemish Pass Basin have been included in the consolidated statements of income (loss) and the consolidated balance sheets in Exploration and Production in the Upstream segment.

Joint Venture

Husky-CNOOC Madura Ltd.

The Company currently holds 40 percent joint control in Husky-CNOOC Madura Ltd., which is engaged in exploring for oil and gas resources in Indonesia with a fiscal year end of December 31. Results of the joint venture are included in the consolidated statements of income (loss) in Exploration and Production in the Upstream segment.

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

Results of Operations

($ millions, except share of equity investment)	**2015**	2014
Revenues	–	–
Expenses	**(25)**	(49)
Net loss	**(25)**	(49)
Share of equity investment (percent)	**40%**	40%
Proportionate share of equity investment	**(5)**	(6)

Balance Sheets

($ millions, except share of equity investment)	**December 31, 2015**	December 31, 2014
Current assets[(1)]	**79**	43
Non-current assets	**780**	574
Current liabilities	**(46)**	(25)
Non-current liabilities	**(559)**	(359)
Net assets	**254**	233
Share of net assets (percent)	**40%**	40%
Carrying amount in statement of balance sheets	**359**	237

[(1)] *Current assets include cash and cash equivalents of $34 million (2014- $15 million).*

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

Note 12 Bank Operating Loans

At December 31, 2015, the Company had unsecured short-term borrowing lines of credit with banks totalling $645 million (December 31, 2014 – $645 million) and letters of credit under these lines of credit totalling $216 million (December 31, 2014 – $188 million). As at December 31, 2015, bank operating loans were nil (December 31, 2014 – nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share of the liability for any drawings under this credit facility is $5 million. As at December 31, 2015, there was nil balance outstanding under this credit facility (December 31, 2014 – nil).

Note 13 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	**December 31, 2015**	December 31, 2014
Trade payables	**636**	550
Accrued liabilities	**1,498**	1,917
Dividend payable *(note 18)*	**296**	295
Stock-based compensation	**6**	53
Derivatives due within one year	**18**	27
Contingent consideration *(note 24)*	–	40
Other	**73**	107
End of year	**2,527**	2,989

Note 14 Debt and Credit Facilities

Short-term Debt

($ millions)	**December 31, 2015**	December 31, 2014
Commercial paper[1]	**720**	895

[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, 2015 was 0.81 percent per annum (December 31, 2014 - 1.24 percent).*

Long-term Debt

($ millions)	Maturity	Canadian $ Amount **December 31, 2015**	Canadian $ Amount December 31, 2014	U.S. $ Denominated **December 31, 2015**	U.S. $ Denominated December 31, 2014
Long-term debt					
Syndicated Credit Facility	2018	**499**	–	–	–
7.55% notes[(1)(3)]	2016	–	232	–	200
6.20% notes[(1)(5)]	2017	**415**	348	**300**	300
6.15% notes[(1)(4)]	2019	**415**	348	**300**	300
7.25% notes[(1)(5)]	2019	**1,038**	870	**750**	750
5.00% notes[(6)]	2020	**400**	400	–	–
3.95% notes[(1)(5)]	2022	**692**	580	**500**	500
4.00% notes[(1)(5)]	2024	**1,038**	870	**750**	750
3.55% notes[(6)]	2025	**750**	–	–	–
6.80% notes[(1)(5)]	2037	**535**	449	**387**	387
Debt issue costs[(2)]		**(27)**	(26)	–	–
Unwound interest rate swaps *(note 24)*		**4**	26	–	–
Long-term debt		**5,759**	4,097	**2,987**	3,187
Long-term debt due within one year					
3.75% notes[(6)]	2015	–	300	–	–
7.55% notes[(1)(3)]	2016	**277**	–	**200**	–
Long-term debt due within one year		**277**	300	**200**	–

(1) *All of the Company's U.S. denominated debt is designated as a hedge of the Company's net investment in its U.S. refining operations. Refer to Note 24 for foreign exchange risk management through hedge of net investment.*
(2) *Calculated using the effective interest rate method.*
(3) *The 7.55% notes represent unsecured securities under a trust indenture dated October 31, 1996.*
(4) *The 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002.*
(5) *The 6.20%, the 7.25%, the 3.95%, the 4.00% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007.*
(6) *The 3.75%, the 5.00% and the 3.55% notes represents unsecured securities under a trust indenture dated December 21, 2009.*

Credit Facilities

On March 6, 2015, the limit on the $1.63 billion and $1.60 billion revolving syndicated credit facilities were each increased to $2.0 billion. As at December 31, 2015, the Company had no borrowings under its $2.0 billion facility expiring December 14, 2016 and outstanding balance of $499 million under its $2.0 billion facility expiring June 19, 2018.

There continues to be no difference between the terms of these facilities, other than their maturity dates. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

The Company is authorized to issue commercial paper up to a maximum of $1.0 billion having a term not to exceed 365 days. At December 31, 2015, the Company had $720 million outstanding of commercial paper (December 31, 2014 – $895 million), which is supported by its revolving syndicated credit facilities.

The syndicated credit facilities include a leverage covenant used to assess the Company's financial strength. The covenant is calculated as long-term debt including current portion net of certain adjusting items specified in the agreement divided by earnings (loss) from operating activities before DD&A net of certain adjusting items specified in the agreement. The Company was in compliance with the syndicated credit facility covenants at December 31, 2015 and assesses the risk of non-compliance to be low. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated.

Notes

On March 17, 2014, the Company issued U.S. $750 million of 4.00 percent notes due April 15, 2024 under a universal short form base shelf prospectus, equivalent to $829 million in Canadian dollars. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium if the notes are redeemed prior to the three-month period prior to maturity. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On June 15, 2014, the Company repaid the maturing 5.9 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to noteholders was U.S. $772 million, including U.S. $22 million of interest, equivalent to $839 million in Canadian dollars, including interest of $25 million.

On February 23, 2015, the Company filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada (the "Canadian Shelf Prospectus") 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 March 23, 2017. During the 25-month period that the Canadian Shelf Prospectus is effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement. This shelf prospectus replaces the universal short form base shelf prospectus filed with applicable securities regulators in each of the provinces of Canada that expired on January 30, 2015 with $2.75 billion of unused capacity. At December 31, 2015, the Company had unused capacity of $1.9 billion under its Canadian Shelf Prospectus.

On March 12, 2015, the Company repaid the maturing 3.75 percent notes issued under a trust indenture dated December 21, 2009. The amount paid to noteholders was $306 million, including $6 million of interest.

On March 12, 2015, the Company issued $750 million of 3.55 percent notes due March 12, 2025 by way of a prospectus supplement dated March 9, 2015 to the Canadian Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 12 and September 12 of each year, beginning September 12, 2015. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On December 22, 2015, the Company filed a universal short form prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and a U.S registration statement containing the U.S. Shelf Prospectus with the SEC that enables the Company to offer up to U.S. $3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including January 22, 2018. During the 25-month period that the U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement. This shelf prospectus and related U.S. registration statement replaces the universal short form base shelf prospectus filed with the Alberta Securities Commission and the related U.S registration statement filed with the SEC that expired on November 30, 2015 with $2.25 billion of unused capacity. At December 31, 2015 the Company had unused capacity of U.S. $3.0 billion under the U.S. Shelf Prospectus and related U.S registration statement.

The ability of the Company to raise capital utilizing the Canadian Shelf Prospectus or U.S. Shelf Prospectus and related U.S registration statement is dependent on market conditions at the time of sale.

The notes disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread. Interest on the notes disclosed above is payable semi-annually.

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

Note 15 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	December 31, 2015	December 31, 2014
Employee future benefits *(note 19)*	**176**	142
Finance lease obligations	**266**	264
Stock-based compensation	**12**	26
Deferred revenue	**109**	–
Other	**180**	153
End of year	**743**	585

Finance lease obligations

The Company, on behalf of the Sunrise Oil Sands Partnership, entered into an arrangement for the construction and use of pipeline and storage facilities in its oil sands operations. The substance of the arrangement has been determined to be a lease and has been classified as a finance lease. The assets are to be used for a minimum period of 20 years with options to renew.

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

	Within 1 year		After 1 year but no more than 5 years		More than 5 years		Total	
($ millions)	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Future minimum lease payments	**35**	33	**139**	141	**800**	852	**974**	1,026
Interest	**30**	31	**115**	119	**532**	581	**677**	731
Present value of minimum lease payments	**31**	31	**104**	104	**162**	160	**297**	295

Note 16 Asset Retirement Obligations

At December 31, 2015, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $13.9 billion (December 31, 2014 – $15.5 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 46 years into the future. This amount has been discounted using credit-adjusted risk-free rates of 2.7 percent to 5.8 percent (December 31, 2014 – 2.9 percent to 4.8 percent) and an inflation rate of 2 percent (December 31, 2014 - 2 percent). Obligations related to future environmental remediation and cleanup of oil and gas assets are included in the estimated ARO. The Company has deposited $121 million of cash into restricted accounts for funding of future asset retirement obligations of the Asia Pacific Region. These amounts have been reflected in restricted cash in the consolidated balance sheets.

The change in estimate in 2015 is primarily related to an increase in the average discount rate, partially offset by a reduction in the economic life of the assets.

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, 2015 and 2014 is set out below:

Asset Retirement Obligations

($ millions)	2015	2014
Beginning of year	**3,065**	2,918
Additions	**23**	48
Liabilities settled	**(98)**	(167)
Liabilities disposed	**(19)**	(8)
Change in discount rate	**(500)**	279
Change in estimates	**340**	(156)
Exchange adjustment	**52**	18
Accretion *(note 20)*	**121**	133
End of year	**2,984**	3,065
Expected to be incurred within 1 year	**102**	97
Expected to be incurred beyond 1 year	**2,882**	2,968

Note 17 Income Taxes

The major components of income tax expense for the years ended December 31, 2015 and 2014 were as follows:

Income Tax Expense (Recovery)

($ millions)	**2015**	2014
Current income tax		
Current income tax charge	**308**	684
Adjustments to current income tax estimates	**(2)**	33
	306	717
Deferred income tax		
Relating to origination and reversal of temporary differences	**(1,760)**	(186)
Adjustments to deferred income tax estimates	**(67)**	(5)
	(1,827)	(191)

Deferred Tax Items in OCI

($ millions)	**2015**	2014
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**(1)**	(5)
Remeasurement of pension plans	**(3)**	(4)
Exchange differences on translation of foreign operations	**215**	109
Hedge of net investment	**(92)**	(39)
	119	61

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, 2015 and 2014 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	**2015**	2014
Earnings (loss) before income taxes		
Canada	**(6,245)**	1,515
United States	**241**	(180)
Other foreign jurisdictions	**633**	449
	(5,371)	1,784
Statutory Canadian income tax rate (percent)	**27.0%**	25.8%
Expected income tax	**(1,450)**	461
Effect on income tax resulting from:		
Capital gains and losses	**2**	(2)
Foreign jurisdictions	**23**	(26)
Non-taxable items	**(31)**	4
Revaluation of foreign tax pools	**(14)**	47
Other – net	**(51)**	42
Income tax expense (recovery)	**(1,521)**	526

The statutory tax rate is 27.0 percent in 2015 (2014 – 25.8 percent). The increase in rate from the prior year is largely the result of the Alberta provincial corporate tax rate increasing from 10 percent to 12 percent, effective July 1, 2015. This rate change has caused deferred income tax expense and the deferred income tax liability to increase by $157 million for the year ended December 31, 2015.

Included in income tax expense for the year ended December 31, 2015 is a $1,357 million deferred income tax recovery related to the non-cash property, plant and equipment impairment charge of $5,021 million on crude oil and natural gas assets located in Western Canada in the Upstream Exploration and Production segment.

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

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2015	Recognized in Earnings	Recognized in OCI	Other	**December 31, 2015**
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(5,840)	**1,853**	**(240)**	**(6)**	**(4,233)**
Foreign exchange gains taxable on realization	(35)	**(100)**	**93**	–	**(42)**
Debt issue costs	(1)	–	–	–	**(1)**
Deferred tax assets					
Pension plans	39	**1**	**3**	–	**43**
Asset retirement obligations	870	**6**	**16**	–	**892**
Loss carry-forwards	87	**(21)**	**9**	–	**75**
Financial assets at fair value	12	**1**	–	–	**13**
Other temporary differences	54	**87**	–	–	**141**
	(4,814)	**1,827**	**(119)**	**(6)**	**(3,112)**

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2014	Recognized in Earnings	Recognized in OCI	Other	December 31, 2014
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(5,789)	75	(124)	(2)	(5,840)
Foreign exchange gains taxable on realization	(60)	(19)	44	–	(35)
Debt issue costs	3	(4)	–	–	(1)
Deferred tax assets					
Pension plans	35	–	4	–	39
Asset retirement obligations	812	50	8	–	870
Loss carry-forwards	51	29	7	–	87
Financial assets at fair value	(8)	20	–	–	12
Other temporary differences	14	40	–	–	54
	(4,942)	191	(61)	(2)	(4,814)

At December 31, 2015, the Company had $174 million (December 31, 2014 – $234 million) of U.S. tax losses that will expire between 2030 and 2034. The Company has recorded deferred tax assets in respect of these losses, as there are sufficient taxable temporary differences in the U.S. jurisdiction to utilize these losses.

Note 18 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, 2013	983,379,074	6,974
Stock dividends	315,419	11
Options exercised	43,569	1
December 31, 2014	983,738,062	6,986
Stock dividends	**590,853**	**14**
December 31, 2015	**984,328,915**	**7,000**

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.

During the year ended December 31, 2015, the Company declared dividends payable of $1.20 per common share (2014 – $1.20 per common share), resulting in dividends of $1,181 million (2014 – $1,180 million). An aggregate of $1,167 million was paid in cash and $14 million was paid in common shares during 2015 (2014 – $1,169 million in cash and $11 million in common shares). At December 31, 2015, $296 million in common shares was payable to shareholders on account of dividends declared on October 30, 2015 (December 31, 2014 – $295 million , including $292 million cash and $3 million common shares). Refer to Note 25 for changes to the Company's quarterly common share dividend.

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, 2013	12,000,000	291
Series 3 issued, net of share issue costs	10,000,000	243
December 31, 2014	22,000,000	534
Series 5 issued, net of share issue costs	**8,000,000**	**195**
Series 7 issued, net of share issue costs	**6,000,000**	**145**
December 31, 2015	**36,000,000**	**874**

Cumulative Redeemable Preferred Shares Dividends	**2015**		2014	
($ millions)	Declared	Paid	Declared	Paid
Series 1 Preferred Shares	**13**	**13**	13	13
Series 3 Preferred Shares	**12**	**12**	–	–
Series 5 Preferred Shares	**7**	**7**	–	–
Series 7 Preferred Shares	**4**	**4**	–	–
	36	**36**	13	13

At December 31, 2015 and 2014, there were no Preferred Share dividends payable.

Holders of the Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 4.45 percent annually for an initial period ending March 31, 2016, 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 5-year Government of Canada bond yield plus 1.73 percent. Holders of Series 1 Preferred Shares have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"), subject to certain conditions, on March 31, 2016 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 at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 1.73 percent, as and when declared by the Company's Board of Directors.

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

On March 12, 2015, the Company issued 8 million Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $200 million, by way of a prospectus supplement dated March 5, 2015, to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $195 million. Holders of the Series 5 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the board of directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"), subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent.

On June 17, 2015, the Company issued 6 million Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $150 million, by way of a prospectus supplement dated June 10, 2015, to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $145 million. Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the board of directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

Stock Option Plan

Pursuant to the Incentive Stock Option Plan (the "Option Plan"), the Company may grant from time to time to officers and 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 Corporation, 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 Corporation that he or she wishes to surrender his or her stock options to the Corporation in lieu of exercise.

Included in accounts payable and accrued liabilities and other long-term liabilities in the consolidated balance sheets at December 31, 2015 was $1 million (December 31, 2014 – $41 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, 2015 was $39 million (2014 – $39 million recovery). At December 31, 2015, stock options exercisable for cash had an intrinsic value of nil (December 31, 2014 – $15 million).

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

Outstanding and Exercisable Options	2015		2014	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**26,742**	**29.47**	28,937	28.20
Granted[(1)]	**5,681**	**25.35**	6,769	33.41
Exercised for common shares	**–**	**–**	(44)	27.57
Surrendered for cash	**(632)**	**26.65**	(7,289)	27.94
Expired or forfeited	**(4,170)**	**28.76**	(1,631)	30.20
Outstanding, end of year	**27,621**	**28.79**	26,742	29.47
Exercisable, end of year	**16,635**	**28.59**	13,717	27.97

(1) *Options granted during the year ended December 31, 2015 were attributed a fair value of $2.56 per option (2014 – $4.08) at grant date.*

Outstanding and Exercisable Options	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$14.63 – $29.99	17,039	26.43	1.98	11,509	26.96
$30.00 – $36.21	10,582	32.59	2.72	5,126	32.26
December 31, 2015	**27,621**	**28.79**	**2.26**	**16,635**	**28.59**

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, 2015	December 31, 2014
	Tandem Options	Tandem Options
Dividend per option	**1.20**	1.20
Range of expected volatilities used *(percent)*	**24.6 - 54.8**	20.9 - 61.8
Range of risk-free interest rates used *(percent)*	**0.4 - 0.7**	0.9 - 1.4
Expected life of share options from vesting date *(years)*	**1.86**	1.81
Expected forfeiture rate *(percent)*	**9.4**	9.8
Weighted average exercise price	**29.03**	28.90
Weighted average fair value	**0.03**	1.85

The expected life of the share options is based on historical data and current expectations and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility over a period similar to the expected life of the options is indicative of future trends, which may also not necessarily be the actual outcome.

Performance Share Units

In February 2010, the Compensation Committee of the Board of Directors of the Company established the Performance Share Unit Plan for executive officers and certain employees of the Company. The term of each PSU is three years, and the PSU vests on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company's total shareholder return relative to a peer group of companies and achieving a ROCIU target set by the Company. ROCIU equals net earnings plus after tax interest expense and before impairment and select exploration charges divided by; the two-year average capital employed, less any capital invested in assets that are not in use. 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, 2015, the carrying amount of the liability relating to PSUs was $17 million (December 31, 2014 – $38 million). The total recovery recognized in selling, general and administrative expenses in the consolidated statements of income (loss) for the PSUs for the year ended December 31, 2015 was nil (2014 – expense of $22 million). The Company paid out $21 million (2014 - $11 million paid) for performance share units which vested in the year. The weighted average contractual life of the PSUs at December 31, 2015 was one and a half years (December 31, 2014 – two years).

The number of PSUs outstanding was as follows:

Performance Share Units	2015	2014
Beginning of year	**4,159,228**	2,791,875
Granted	**2,374,330**	2,064,100
Exercised	**(775,313)**	(357,628)
Forfeited	**(635,619)**	(339,119)
Outstanding, end of year	**5,122,626**	4,159,228
Vested, end of year	**1,176,980**	1,372,974

Earnings per Share

Earnings per Share

($ millions)	2015	2014
Net earnings (loss)	**(3,850)**	1,258
Effect of dividends declared on preferred shares in the year	**(36)**	(13)
Net earnings (loss) – basic	**(3,886)**	1,245
Dilutive effect of accounting for share options as equity-settled[1]	**(57)**	(65)
Net earnings (loss) – diluted	**(3,943)**	1,180
(millions)		
Weighted average common shares outstanding – basic	**984.1**	983.6
Effect of stock dividends declared in the year	–	1.7
Weighted average common shares outstanding – diluted	**984.1**	985.3
Earnings (loss) per share – basic ($/share)	**(3.95)**	1.26
Earnings (loss) per share – diluted ($/share)	**(4.01)**	1.20

[1] *Stock-based compensation recovery was $39 million based on cash-settlement for the year ended December 31, 2015 (2014 – $39 million recovery). Stock-based compensation expense was $18 million based on equity-settlement for the year ended December 31, 2015 (2014 - $26 million expense). For the year ended December 31, 2015, equity-settlement of share options was considered more dilutive than the cash-settlement of share options and as such, was used to calculate earnings per share - diluted.*

For the year ended December 31, 2015, 28 million tandem options (2014 – 19 million) were excluded from the calculation of diluted earnings per share as these options were anti-dilutive.

Note 19 Pensions and Other Post-employment Benefits

The Company currently provides defined contribution pension plans for all qualified employees and two other post-employment benefit plans to its retirees. The Company also maintains a defined benefit pension plan, which is closed to new entrants. The measurement date of all plan assets and the accrued benefit obligations was December 31, 2015. The most recent actuarial valuation was December 31, 2014 for the Canadian defined benefit plan. The most recent actuarial valuation was December 31, 2014 for the Canadian Other Post-employment benefit plan. The most recent actuarial valuation of the U.S. Other Post-employment benefit plan was January 1, 2015.

Defined Contribution Pension Plan

During the year ended December 31, 2015, the Company recognized a $44 million expense (2014 – $42 million) for the defined contribution plan and the two U.S. 401(k) plans in net earnings.

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

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 as follows:

DB Pension Plan

($ millions)	**December 31, 2015**	December 31, 2014	December 31, 2013
Fair value of plan assets	**181**	180	173
Defined benefit obligation	**(177)**	(179)	(180)
Funded status	**4**	1	(7)
Net asset (liability)	**4**	1	(7)
Non-current asset (liability)	**4**	1	(7)

OPEB Plans

($ millions)	**December 31, 2015**	December 31, 2014	December 31, 2013
Fair value of plan assets	**–**	–	–
Defined benefit obligation	**(180)**	(143)	(109)
Funded status	**(180)**	(143)	(109)
Net liability	**(180)**	(143)	(109)
Non-current liability	**(180)**	(143)	(109)

The following tables summarize the experience adjustments arising on the DB Pension Plan's and the OPEB Plans' liabilities:

DB Pension Plan

($ millions)	**2015**	2014	2013
Experience adjustments arising on plan liabilities	**0.1**	(1.5)	0.4

OPEB Plans

($ millions)	**2015**	2014	2013
Experience adjustments arising on plan liabilities	**16.5**	(0.2)	(0.5)

The following tables summarize changes to the net balance sheet position and amounts recognized in net earnings and OCI for the DB Pension Plan and the OPEB Plans for the years ended December 31, 2015 and 2014:

DB Pension Plan and OPEB Plans Net Asset (Liability)	DB Pension Plan		OPEB Plans	
($ millions)	**2015**	2014	**2015**	2014
Beginning of year	**1**	(7)	**(143)**	(109)
Employer contributions	**2**	4	**–**	–
Benefit cost	**(4)**	(1)	**(16)**	(12)
Benefit paid	**–**	–	**3**	1
Remeasurements				
Actuarial gain (loss) due to liability experience	**–**	2	**(17)**	–
Actuarial gain (loss) due to liability assumption changes	**2**	(19)	**(7)**	(23)
Return on plan assets (greater) less than discount rate	**3**	22	**–**	–
End of year	**4**	1	**(180)**	(143)

DB Pension Plan and OPEB Plans	DB Pension Plan		OPEB Plans	
($ millions)	**2015**	2014	**2015**	2014
Amounts recognized in net earnings				
Current service cost	**4**	2	**10**	7
Net Interest cost	**–**	1	**6**	5
Gain on settlement	**–**	(2)	**–**	–
Benefit cost (gain)	**4**	1	**16**	12
Remeasurements				
Actuarial (gain) loss due to liability experience	**–**	(2)	**17**	–
Actuarial (gain) loss due to liability assumption changes	**(2)**	19	**7**	23
Loss (gain) on plan assets	**(3)**	(22)	**–**	–
Remeasurement effects recognized in OCI	**(5)**	(5)	**24**	23

The following tables summarize changes to the defined benefit obligation for the DB Pension Plan and the OPEB Plans:

Defined Benefit Obligation	DB Pension Plan		OPEB Plans	
($ millions)	**2015**	2014	**2015**	2014
Beginning of year	**179**	180	**143**	109
Current service cost	**4**	2	**10**	7
Interest cost	**7**	8	**6**	5
Benefits paid	**(11)**	(10)	**(3)**	(1)
Gain on settlements	**–**	(2)	**–**	–
Settlements	**–**	(16)	**–**	–
Remeasurements				
Actuarial (gain) loss – experience	**–**	(2)	**17**	–
Actuarial (gain) loss – demographic assumptions	**–**	3	**–**	3
Actuarial (gain) loss – financial assumptions	**(2)**	16	**7**	20
Curtailment gain	**–**	–	**–**	–
End of year	**177**	179	**180**	143

The following table summarizes changes to the DB Pension Plan assets during the year:

Fair Value of Plan Assets

($ millions)	**2015**	2014
Beginning of year	**180**	173
Contributions by employer	**2**	4
Benefits paid	**(11)**	(10)
Interest income	**7**	7
Return on plan assets greater (less) than discount rate	**3**	22
Settlements	**–**	(16)
End of year	**181**	180

The following long-term assumptions were used to estimate the value of the defined benefit obligations, the plan assets and the OPEB Plans:

DB Pension Plan Long-term Assumptions

	Canada - DB Pension Plan	
(percent)	**2015**	2014
Discount rate for benefit expense	**3.7**	4.5
Discount rate for benefit obligation	**3.8**	3.7
Rate of compensation expense	**3.5**	3.5

OPEB Plans Long-term Assumptions

	OPEB Plans	
(percent)	**2015**	2014
Discount rate for benefit expense	**3.7 - 3.9**	4.4 - 4.7
Discount rate for benefit obligation	**4.0 - 4.1**	3.7 - 3.9
Dental care escalation rate	**4.5**	4.5
Provincial health care premium	**2.5**	2.5

The average health care cost trend rate used for the benefit expense for the Canadian OPEB Plan was 6.5 percent for 2015, grading 0.5 percent per year for 3 years to 5.0 percent in 2018 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 7.0 percent for 2016, grading 0.4 percent per year for 5 years to 5.0 percent in 2021 and thereafter.

The average health care cost trend rate used for the benefit expense for the U.S. OPEB Plan was 6.8 percent for 2015, grading 0.25 percent per year for 7 years to 5.0 percent per year in 2022 and thereafter. The average health care cost trend rate used for the obligation related to the U.S. OPEB Plan was 6.5 percent for 2016, grading 0.25 percent per year for 6 years to 5.0 percent in 2022 and thereafter.

The medical cost trend rate assumption has a significant effect on amounts reported for the OPEB plans. A 1 percent increase or decrease in the estimated trend rate would have the following effects:

Medical Cost Trend Rate Sensitivity Analysis

($ millions)	1% increase	1% decrease
Effect on benefit cost recognized in net earnings	3.5	(2.8)
Effect on defined benefit obligation	33.1	(27.1)

During 2015, the Company contributed $2 million (2014 – $4 million) to the defined benefit pension plan assets and is expecting to contribute $2 million in 2016. Benefits of $11 million are expected to be paid in 2016.

The Company adheres to a Statement of Investment Policies and Procedures (the "Policy"). Plan assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The composition of the DB Pension Plan assets at December 31, 2015 and 2014 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	2015	2014
Money market type funds	0 – 5	**0.5**	0.5
Equity securities	30 – 50	**41.5**	40.6
Debt securities	50 – 65	**58.0**	58.9

Note 20 Financial Items

Financial Items

($ millions)	2015	2014
Foreign exchange		
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(34)**	7
Gains on contribution receivable *(note 11)*	–	6
Gains on non-cash working capital	**35**	42
Other foreign exchange gains	**42**	26
Net foreign exchange gains	**43**	81
Finance income		
Contribution receivable *(note 11)*	–	1
Interest income	–	7
Other	**35**	–
Finance income	**35**	8
Finance expenses		
Long-term debt	**(300)**	(267)
Contribution payable *(note 11)*	**(16)**	(85)
Other	**(18)**	(5)
	(334)	(357)
Interest capitalized[(1)]	**157**	258
	(177)	(99)
Accretion of asset retirement obligations *(note 16)*	**(121)**	(133)
Accretion of other long-term liabilities *(note 24)*	–	(1)
Finance expenses	**(298)**	(233)
	(220)	(144)

(1) *Interest capitalized on project costs in 2015 is calculated using the Company's annualized effective interest rate of 5 percent (2014 – 6 percent).*

Note 21 Cash Flows – Change in Non-cash Working Capital

Non-cash Working Capital

($ millions)	2015	2014
Decrease (increase) in non-cash working capital		
Accounts receivable	**844**	964
Inventories	**570**	191
Prepaid expenses	**10**	(76)
Accounts payable and accrued liabilities	**(926)**	(508)
Change in non-cash working capital	**498**	571
Relating to:		
Operating activities	**651**	871
Financing activities	**179**	33
Investing activities	**(332)**	(333)

Note 22 Commitments and Contingencies

At December 31, 2015, the Company had commitments that require the following minimum future payments, which are not accrued in the consolidated balance sheets:

Minimum Future Payments for Commitments

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Operating leases	204	656	1,034	1,894
Firm transportation agreements	363	1,338	2,321	4,022
Unconditional purchase obligations[(1)]	2,337	4,937	1,346	8,620
Lease rentals and exploration work agreements	181	382	1,343	1,906
Obligations to fund equity investee[(2)]	6	228	417	651
	3,091	7,541	6,461	17,093

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.*
(2) *Equity investee refers to the Company's investment in Husky-CNOOC Madura Limited which is accounted for using the equity method.*

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, including two claims with the same contractor in which the Company is both defendant and plaintiff. 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 23 Related Party Transactions

Significant subsidiaries and jointly controlled entities at December 31, 2015 and the Company's percentage equity interest (to the nearest whole number) are set out below:

Significant Subsidiaries and Joint Operations	%	Jurisdiction
Subsidiary of Husky Energy Inc.		
Husky Oil Operations Limited	100	Alberta
Subsidiaries and jointly controlled entities of Husky Oil Operations Limited		
Husky Oil Limited Partnership	100	Alberta
Husky Terra Nova Partnership	100	Alberta
Husky Downstream General Partnership	100	Alberta
Husky Energy Marketing Partnership	100	Alberta
Husky Energy International Corporation	100	Alberta
Sunrise Oil Sands Partnership	50	Alberta
BP-Husky Refining LLC	50	Delaware
Lima Refining Company	100	Delaware
Husky Marketing and Supply Company	100	Delaware

Each of the related party transactions described below was made on terms equivalent to those that prevail in arm's length transactions unless otherwise noted.

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. For the year ended December 31, 2015, the amount of natural gas sales to Meridian totalled $50 million (December 31, 2014 - $78 million). For the year ended December 31, 2015, the amount of steam purchased by the Company from Meridian totalled $16 million (December 31, 2014 - $25 million). For the year ended December 31, 2015, the total cost recovery by the Company for facilities services was $17 million (December 31, 2014 - $9 million). At December 31, 2015 the Company had $2 million due from Meridian with respect to these transactions (December 31, 2014 - $2 million).

At December 31, 2015, $38 million of the May 11, 2009 7.25 percent notes were held by related parties and are included in long-term debt in the Company's consolidated balance sheets. Mr. Canning Fok, co-chair and a director of the Company, indirectly subscribed for $3 million of the senior notes. Ace Dimension Limited subscribed for $35 million of the senior notes. These related party transactions were measured at fair market value at the date of the transactions and have been carried out on the same terms as applied with unrelated parties who purchased the senior notes pursuant to the public offering of the senior notes.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million in a private placement to its principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares in Canada.

On June 29, 2011, the Company issued 7.4 million common shares at a price of $27.05 per share for total gross proceeds of $200 million in a private placement to its then principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares.

The Company defines its key management as the officers and executives within the executive department 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)	**2015**	2014
Short-term employee benefits[(1)]	**15**	18
Stock-based compensation[(2)]	**8**	10
	23	28

(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 24 Financial Instruments and Risk Management

Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, derivatives, long-term income tax receivable, portions of other assets and other long-term liabilities.

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, 2015**	December 31, 2014
Commodity contracts - fair value through profit or loss ("FVTPL")		
Natural gas[1]	**6**	(5)
Crude oil[2]	**8**	4
Foreign currency contracts - FVTPL		
Foreign currency forwards	**–**	(1)
Other assets - FVTPL	**2**	2
Contingent consideration	**–**	(40)
Hedge of net investment[3][4]	**(940)**	(353)
End of year	**(924)**	(393)

(1) Natural gas contracts includes a $14 million decrease at December 31, 2015 (December 31, 2014 - $12 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 $67 million at December 31, 2015 (December 31, 2014 - $87 million).

(2) Crude oil contracts includes a $6 million decrease at December 31, 2015 (December 31, 2014 - $21 million decrease) 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 $190 million at December 31, 2015 (December 31, 2014 - $199 million)

(3) Hedging instruments are presented net of tax.

(4) Represents the translation of the Company's U. S. denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.

The Company's other financial instruments that are not related to derivatives, contingent consideration or hedging activities are included in cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, long-term income tax receivable and portions of other assets and other long-term liabilities. These financial instruments are classified as loans and receivables or other financial liabilities and are carried at amortized cost. Excluding long-term debt, the carrying values of these financial instruments and cash and cash equivalents approximate their fair values.

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. The estimated fair value of long-term debt at December 31, 2015 was $5.6 billion (December 31, 2014 – $4.8 billion).

The estimation of the fair value of commodity derivatives and held-for-trading inventories incorporates exit prices and adjustments for quality and location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability. The estimation of the fair value of the net investment hedge incorporates foreign exchange rates and market interest rates from financial institutions. All financial assets and liabilities are classified as Level 2 measurements. The Company's contingent consideration payments, previously classified as Level 3 measurements, were fully settled during 2015. During the year ended December 31, 2015, there were no transfers between Level 1 and Level 2 fair value measurements, and no transfers into and out of Level 3 fair value measurements.

Contingent consideration payments, based on the average differential between heavy and synthetic crude oil prices, were classified as Level 3 fair value measurements and included in accounts payable and accrued liabilities and other long-term liabilities. The fair value of the contingent consideration was determined through forecasts of synthetic crude oil volumes, crude oil prices and forward price differentials deemed specific to the Company's Upgrader. A reconciliation of changes in the fair value of contingent consideration is provided below:

Contingent consideration

($ millions)	**2015**	2014
Beginning of year	**40**	60
Accretion *(note 20)*	**–**	1
Upside interest payment	**(30)**	(32)
Increase (decrease) on revaluation[1]	**(10)**	11
End of year	**–**	40

(1) *Revaluation of the contingent consideration liability is recorded in other – net in the Consolidated Statements of Income (loss).*

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 and credit and contract risks. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. Derivative instruments are recorded at fair value in accounts receivable, inventory, other assets and accounts payable and accrued liabilities in the Consolidated Balance Sheets. The Company has crude oil and natural gas inventory held in storage related to commodity price risk management contracts that is recognized at fair value. The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels.

Responsibility for risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

a) Market Risk

i) Commodity Price Risk Management

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

The Company's results will also be impacted by a decrease in the price of crude oil inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. The Company also has natural gas inventory in storage that could have an impact on earnings based on changes in natural gas prices. These inventories are subject to a lower of cost or net realizable value test on a monthly basis.

ii) Foreign Exchange Risk Management

The Company's results are affected by the exchange rates between various currencies, including the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. The majority of the Company's expenditures are in Canadian dollars. The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars to hedge against these fluctuations and to mitigate its exposure to foreign exchange risk.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related finance expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company may enter into cash flow hedges using cross currency debt swap arrangements. In addition, the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a foreign operation that has a U.S. dollar functional currency. The unrealized foreign exchange loss related to this hedge is recorded in OCI.

At December 31, 2015, the Company had designated U.S. 3.2 billion denominated debt as a hedge of the Company's net investment in its U.S. refining operations (December 31, 2014 – U.S. 2.9 billion). For the year ended December 31, 2015, the unrealized loss arising from the translation of the debt was $587 million (2014 – unrealized loss of $260 million), net of tax recovery of $92 million (2014 – recovery of $39 million), which were recorded in hedge of net investment within other comprehensive income.

Interest Rate Risk Management

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. To mitigate risk related to interest rates, the Company may enter into fair value hedges using interest rate swaps. At December 31, 2015, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that had previously been designated as a fair value hedge was $4 million (December 31, 2014 – $26 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $22 million for the year ended December 31, 2015 (December 31, 2014 – $24 million).

At December 31, 2015, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $20 million (December 31, 2014 – $23 million), net of tax of $7 million (December 31, 2014 – net of tax of $8 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an offset to finance expense of $3 million for the year ended December 31, 2015 (December 31, 2014 – $3 million).

iii) Earnings Impact of Market Risk Management Contracts

The gains (losses) recognized on other risk management positions for the years ended December 31, 2015 and 2014 are set out below:

Earnings Impact *($ millions)*	2015 Marketing and Other	 Other – Net	 Net Foreign Exchange
Commodity Price			
Natural gas	**11**	–	–
Crude oil	**4**	–	–
	15	–	–
Foreign Currency			
Foreign currency forwards[1]	–	**1**	**(28)**
	15	**1**	**(28)**

[1] *Unrealized gains or losses from short-dated foreign currency forwards are included in other – net, while realized gains or losses are included in net foreign exchange gains in the consolidated statements of income (loss).*

Earnings Impact *($ millions)*	2014 Marketing and Other	 Other – Net	 Net Foreign Exchange
Commodity Price			
Natural gas	(37)	–	–
Crude oil	(37)	–	–
	(74)	–	–
Foreign Currency			
Foreign currency forwards[1]	–	(1)	(47)
	(74)	(1)	(47)

[1] *Unrealized gains or losses from short-dated foreign currency forwards are included in other – net, while realized gains or losses are included in net foreign exchange gains in the consolidated statements of income (loss).*

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, 2015 Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	**87**	**(37)**	**50**
Normal purchase and sale agreements	**353**	**(122)**	**231**
End of year	**440**	**(159)**	**281**
Financial Liabilities			
Financial derivatives	**(108)**	**48**	**(60)**
Normal purchase and sale agreements	**(368)**	**68**	**(300)**
End of year	**(476)**	**116**	**(360)**

Offsetting Financial Assets and Liabilities ($ millions)	As at December 31, 2014 Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	264	(222)	42
Normal purchase and sale agreements	1,078	(616)	462
End of year	1,342	(838)	504
Financial Liabilities			
Financial derivatives	(17)	11	(6)
Normal purchase and sale agreements	(588)	219	(369)
End of year	(605)	230	(375)

Market Risk Sensitivity Analysis

A sensitivity analysis for commodities, foreign currency exchange and interest rate risks has been calculated by increasing or decreasing commodity prices, foreign currency exchange rates or interest rates, as appropriate. These sensitivities represent the increase or decrease in earnings before income taxes resulting from changing the relevant rates, with all other variables held constant. These sensitivities have only been applied to financial instruments held at fair value. The Company's process for determining these sensitivities has not changed during the year.

Commodity Price Risk[1] ($ millions)	10% price increase	10% price decrease
Crude oil price	36	(36)
Natural gas price	(6)	6

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, 2015.*
[2] *Based on the U.S./Canadian dollar exchange rate as at December 31, 2015.*

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 capability to raise capital from various debt and equity capital markets under its shelf prospectuses. The Company prepares annual capital expenditure budgets, which are monitored and updated as required. In addition, the Company requires authorizations for expenditures on projects, which assists with the management of capital.

Since the Company operates in the Upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt. The Company's upstream capital programs are funded principally by cash provided from operating activities and issuances of debt and equity. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow of maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. Occasionally, the Company will economically hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company had the following available credit facilities as at December 31, 2015:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)] *(note 12)*	**645**	**429**
Syndicated bank facilities[(2)] *(note 14)*	**4,000**	**2,781**
End of year	**4,645**	**3,210**

(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 $1.9 billion and unused capacity under the U.S Shelf Prospectus and related U.S registration statement of U.S. $3.0 billion. The ability of the Company to raise additional capital utilizing these 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.

The following are the contractual maturities of the Company's financial liabilities (other than commitments disclosed in Note 22) as at December 31, 2015:

Contractual Maturities of Financial Liabilities

($ millions)	2016	2017	2018	2019	2020	Thereafter
Accounts payable and accrued liabilities	2,527	–	–	–	–	–
Other long-term liabilities	31	32	27	25	22	160
Long-term debt	277	415	499	1,453	400	3,015

ii) Credit and Contract Risk Management

Credit and contract risk represent the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms. The Company actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective. The Company's accounts receivables are broad based with customers in the energy industry and midstream and end user segments and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company had one external customer that constituted more than 10 percent of gross revenues during the years ended December 31, 2015 and December 31, 2014. Sales to this customer were approximately $2,868 million for the year ended December 31, 2015 (2014 - $3,766 million).

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, 2015:

Accounts Receivable Aging

($ millions)	**December 31, 2015**
Current	**682**
Past due (1 – 30 days)	**307**
Past due (31 – 60 days)	**17**
Past due (61 – 90 days)	**3**
Past due (more than 90 days)	**36**
Allowance for doubtful accounts	**(31)**
	1,014

The Company recognizes a valuation allowance when collection of accounts receivable is in doubt. Accounts receivable are impaired directly when collection of accounts receivable is no longer expected. For the year ended December 31, 2015, the Company wrote off $7 million (2014 – $1 million) of uncollectible receivables.

Note 25 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 $23.3 billion as at December 31, 2015 (December 31, 2014 – $25.9 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to cash flow from operations and debt to capital employed. Debt to cash flow from operations is defined as total debt divided by cash flow from operations which is equal to net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment and other non-cash items. Debt to capital employed is defined as long-term debt, long-term debt due within one year, and short-term debt divided by the two year average capital employed which is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity.

The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to cash flow from operations ratio of less than 1.5 times. At December 31, 2015, debt to capital employed was 28.9 percent (December 31, 2014 – 20 percent) and debt to cash flow from operations was 2.0 times (December 31, 2014 – 1.0 times) exceeding the Company's targets. The increase in the Company's debt to capital and debt to cash flow from operations ratios as at December 31, 2015 reflects the impact of sharp declines in global crude oil and North American natural gas benchmark pricing in the year which resulted in significantly lower cash flow from operations compared to 2014 and the weakening of the Canadian dollar which impacted the translation of the Company's U.S. denominated long-term debt. The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle including but not limited to a reduction of 2016 budgeted capital spending, the suspension of the common share quarterly dividend, the continued transition to low sustaining capital projects and the planned disposition of select midstream and legacy Western Canada Upstream assets. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however, the syndicated credit facilities include a leverage covenant used to assess the Company's financial strength. The covenant is calculated as long-term debt including current portion net of certain adjusting items specified in the agreement divided by earnings (loss) from operating activities before DD&A net of certain adjusting items specified in the agreement. The Company was in compliance with the syndicated credit facility covenants at December 31, 2015 and assesses the risk of non-compliance to be low. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated.

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

Note 26 Government Grants

The Company has government assistance programs in place where it receives funding based on ethanol production and sales from the Lloydminster and Minnedosa ethanol plants from the Department of Natural Resources and the Government of Manitoba. Applications for funding are submitted quarterly. During 2015, the Company received $21 million (2014 – $33 million) under these programs. The grants are accrued for operational purposes and have been recorded as revenues in the consolidated statements of income (loss). The programs expired in 2015.

Note 27 Production, Operating and Transportation and Selling, General and Administrative Expenses

The following tables summarizes production, operating and transportation expenses in the consolidated statements of income (loss) for the years ended December 31, 2015 and 2014:

($ millions)	**2015**	2014
Services and support costs	**1,144**	1,281
Salaries and benefits	**626**	603
Materials, equipment rentals and leases	**298**	200
Energy and utility	**450**	616
Licensing fees	**251**	211
Transportation	**62**	53
Other	**163**	155
	2,994	3,119

The following table summarizes selling, general and administrative expenses in the consolidated statements of income (loss) for the years ended December 31, 2015 and 2014:

($ millions)	**2015**	2014
Employee costs[(1)]	**251**	318
Stock based compensation[(2)]	**(39)**	(17)
Contract services	**77**	102
Equipment rentals and leases	**31**	29
Maintenance and other	**22**	30
	342	462

(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 (recovery) represents the cost to the Company for participation in share-based payment plans.*