MANAGEMENT'S DISCUSSION AND ANALYSIS

February 11, 2015

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1. Summary of Quarterly Results

	Three months ended								Year ended	
Quarterly Summary	**Dec. 31**	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	**Dec. 31**	Dec. 31
($ millions, except where indicated)	**2014**	2014	2014	2014	2013	2013	2013	2013	**2014**	2013
Production *(mboe/day)*	**359.6**	341.1	333.6	325.9	308.3	308.5	309.9	321.3	**340.1**	312.0
Gross revenues	**5,875**	6,690	6,614	5,943	6,132	6,036	6,206	5,807	**25,122**	24,181
Net earnings (loss)	**(603)**	571	628	662	177	512	605	535	**1,258**	1,829
Per share – Basic	**(0.62)**	0.58	0.63	0.67	0.18	0.52	0.61	0.54	**1.26**	1.85
Per share – Diluted	**(0.65)**	0.52	0.63	0.66	0.18	0.52	0.59	0.54	**1.20**	1.85
Net operating earnings[(1)]	**147**	571	628	669	375	517	607	535	**2,015**	2,034
Cash flow from operations[(1)]	**1,145**	1,341	1,504	1,536	1,143	1,347	1,449	1,283	**5,535**	5,222
Per share – Basic	**1.16**	1.36	1.53	1.56	1.16	1.37	1.47	1.31	**5.63**	5.31
Per share – Diluted	**1.16**	1.36	1.52	1.56	1.16	1.37	1.47	1.30	**5.62**	5.31

[(1)] Net operating earnings and cash flow from operations are non-GAAP measures. Refer to Section 11 for a reconciliation to the GAAP measures.

Performance

- Production increased by 51.3 mboe/day or 17 percent to 359.6 mboe/day in the fourth quarter of 2014 compared to the fourth quarter of 2013 as a result of:
  - Production from the Liwan Gas Project which began producing in the first quarter of 2014;
  - Strong production performance from heavy oil thermal developments, including the Sandall development which began producing crude oil in the first quarter of 2014; and
  - Increased production from the Ansell liquids-rich natural gas resource play;
  - Partially offset by natural reservoir declines from mature properties in Western Canada and the Atlantic Region.
- Net loss of $603 million included an after-tax impairment charge of $622 million recognized in the fourth quarter of 2014 related to Western Canada crude oil and natural gas properties compared to an after-tax impairment of $204 million recognized in the fourth quarter of 2013, and a provision of $128 million after-tax was recorded to bring inventory to net realizable value.
- Net operating earnings, which exclude charges for impairment and net realizable value provisions, were $147 million in the fourth quarter of 2014 compared to $375 million in the fourth quarter of 2013 with the decrease due to:
  - Lower realized crude oil prices; and
  - Lower U.S. Refining and Marketing margins as falling commodity prices led to first in first out ("FIFO") losses;
  - Partially offset by increased crude oil and natural gas production;
  - Higher realized fixed prices on production from the Liwan Gas Project and higher natural gas benchmark prices in Canada; and
  - Recovery of stock-based compensation expense due to the decrease in the Company's share price.
- Cash flow from operations was $1,145 million in the fourth quarter of 2014 which was comparable to $1,143 million in the fourth quarter of 2013.

Key Projects

- First steam was achieved on Phase 1 of the 60,000 bbls/day (30,000 bbls/day net Husky share) Sunrise Energy Project during the fourth quarter of 2014.
- At the Liwan Gas Project, first gas was achieved at the Liuhua 34-2 gas field and production continued to increase from the Liwan 3-1 field during the fourth quarter of 2014.
- In Indonesia, the contract for the construction and lease of a floating, production, storage and offloading ("FPSO") vessel for the BD field shallow water gas developments on the Madura Strait Block was signed in December 2014.
- In the Atlantic Region, development drilling has commenced on the first production wells for the South White Rose Extension, with first oil anticipated in mid-2015.
- Husky has deferred a final investment decision on the West White Rose Extension wellhead platform development.
- Production from the Hibernia formation well at the North Amethyst field is anticipated to start in the third quarter of 2015, with the delay in start up as a result of rig scheduling.
- At the Sandall heavy oil thermal development, production response continues to be strong with oil rates averaging 5,600 bbls/day in the fourth quarter of 2014.
- Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the third quarter of 2015.
- Site clearing, detailed engineering and module fabrication continued at the two 10,000 bbls/day Edam East and Vawn and the 3,500 bbls/day Edam West thermal projects.
- Western Canada resource play development progressed in the fourth quarter of 2014 with 15 liquids-rich natural gas wells (gross) and five oil wells (gross) drilled and 14 liquids-rich natural gas wells (gross) and nine oil wells (gross) completed including continued development of the Ansell liquids-rich natural gas resource play.
- At the BP-Husky Toledo Refinery, the Hydrotreater Recycle Gas Compressor Project was completed. The project is expected to improve operational integrity and plant performance.

Financial

- Dividends on common shares of $295 million for the third quarter of 2014 were declared during the fourth quarter of 2014, of which $292 million and $3 million were paid in cash and common shares, respectively, on January 2, 2015.

2. Business Environment

Average Benchmarks		Three months ended Dec. 31, 2014	Sept. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Year ended Dec. 31, 2014	Dec. 31, 2013
WTI crude oil[1]	*(U.S. $/bbl)*	**73.15**	97.17	102.99	98.68	97.46	**93.00**	97.97
Brent crude oil[2]	*(U.S. $/bbl)*	**76.27**	101.85	109.61	108.22	108.34	**98.99**	107.91
Canadian light crude 0.3 percent sulphur	*($/bbl)*	**65.90**	88.53	96.29	89.60	88.29	**85.08**	93.85
Western Canadian Select[3]	*(U.S. $/bbl)*	**58.90**	76.99	82.95	75.55	65.26	**73.60**	72.77
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**61.77**	77.96	80.98	72.42	57.70	**73.28**	64.41
NYMEX natural gas[4]	*(U.S. $/mmbtu)*	**4.00**	4.06	4.67	4.94	3.61	**4.42**	3.65
NIT natural gas	*($/GJ)*	**3.80**	4.00	4.44	4.51	2.99	**4.19**	3.00
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**14.14**	20.23	20.17	23.09	32.42	**19.41**	25.33
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**16.09**	18.86	19.27	20.32	18.90	**18.61**	22.21
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**14.04**	17.41	19.40	18.35	11.91	**17.28**	21.30
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.881**	0.918	0.917	0.906	0.953	**0.906**	0.971
Canadian $ Equivalents[5]								
WTI crude oil	*($/bbl)*	**83.03**	105.85	112.31	108.92	102.26	**102.65**	100.90
Brent crude oil	*($/bbl)*	**86.57**	110.95	119.53	119.45	113.68	**109.26**	111.13
WTI/Lloyd crude blend differential	*($/bbl)*	**16.05**	22.04	22.00	25.49	34.02	**21.42**	26.08
NYMEX natural gas	*($/mmbtu)*	**4.54**	4.42	5.09	5.45	3.79	**4.88**	3.76

(1) Prices quoted are near-month contract prices for settlement during the next month.
(2) Dated Brent prices are dated less than 15 days prior to loading for delivery.
(3) Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils and is traded at Hardisty, Alberta. Quoted prices are based on the average price during the month.
(4) Prices quoted are average settlement prices for deliveries during the period.
(5) Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.

The price the Company receives for production from Western Canada is primarily driven by the price of West Texas Intermediate ("WTI"), adjusted to Western Canada, while the majority of the Company's production in the Atlantic and Asia Pacific regions is referenced to the price of Brent. The price of WTI was U.S. $53.27/bbl at the end of 2014 compared with U.S. $98.42/bbl on December 31, 2013. The price of WTI averaged U.S. $73.15/bbl in the fourth quarter of 2014 compared to U.S. $97.46/bbl in the same period of 2013. The price of WTI averaged U.S. $93.00/bbl in 2014 compared to U.S. $97.97/bbl in 2013. The price of Brent was U.S. $54.98/bbl at the end of 2014 compared with U.S. $110.28/bbl on December 31, 2013. The price of Brent averaged U.S. $76.27/bbl in the fourth quarter of 2014 compared to U.S. $108.34/bbl in the same period of 2013. The price of Brent averaged U.S. $98.99/bbl in 2014 compared to U.S. $107.91/bbl in 2013.

Crude oil prices in 2014 benefited from the weakening of the Canadian dollar versus the U.S. dollar. In the fourth quarter of 2014, the price of WTI in U.S. dollars decreased 25 percent compared to a decrease of 19 percent in Canadian dollars compared to the same period in 2013. In 2014, the price of WTI in U.S. dollars decreased 5 percent compared to an increase of 2 percent in Canadian dollars compared to 2013. In the fourth quarter of 2014, the price of Brent in U.S. dollars decreased 30 percent compared to a decrease of 24 percent in Canadian dollars compared to the same period in 2013. In 2014, the price of Brent in U.S. dollars decreased 8 percent compared to a decrease of 2 percent in Canadian dollars compared to 2013.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. The light/heavy crude oil differential averaged U.S. $14.14/bbl or 19 percent of WTI in the fourth quarter of 2014 compared to U.S. $32.42/bbl or 33 percent of WTI in the fourth quarter of 2013. The light/heavy crude oil differential averaged U.S. $19.41/bbl or 21 percent of WTI in 2014 compared to $25.33/bbl or 26 percent of WTI in 2013.

During the fourth quarter of 2014, the NYMEX near-month contract price of natural gas averaged U.S. $4.00/mmbtu compared to U.S. $3.61/mmbtu in the same period of 2013, an increase of 11 percent. During 2014, the NYMEX near-month contract price of natural gas averaged U.S. $4.42/mmbtu compared to U.S. $3.65/mmbtu in 2013, an increase of 21 percent. During the fourth quarter of 2014, the NOVA Inventory Transfer ("NIT") near-month contract price of natural gas averaged $3.80/GJ compared to $2.99/GJ in the same period in 2013, an increase of 27 percent. During 2014, the NIT near-month contract price of natural gas averaged $4.19/GJ compared to $3.00/GJ in 2013, an increase of 40 percent.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities and refined products that receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and international Upstream operations and U.S. dollar denominated debt.

The Canadian dollar was U.S. $0.862 at the end of 2014 compared with U.S. $0.940 on December 31, 2013. In the fourth quarter of 2014, the Canadian dollar averaged U.S. $0.881, weakening by 8 percent compared to U.S. $0.953 during the same period in 2013. In 2014, the Canadian dollar averaged U.S. $0.906 compared to U.S. $0.971 during 2013.

Refining Crack Spreads

The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and do not reflect the actual crude purchase costs or product configuration of a specific refinery.

During the fourth quarter of 2014, the Chicago 3:2:1 crack spread averaged U.S. $14.04/bbl compared to U.S. $11.91/bbl in the same period of 2013. In 2014, the Chicago 3:2:1 crack spread averaged U.S. $17.28/bbl compared to U.S. $21.30/bbl during 2013. In the fourth quarter of 2014, the New York Harbour 3:2:1 crack spread averaged U.S. $16.09/bbl compared to U.S. $18.90/bbl in the same period in 2013. In 2014, the New York Harbour 3:2:1 crack spread averaged U.S. $18.61/bbl compared to U.S. $22.21/bbl in 2013.

Husky's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and time lag between the purchase and delivery of crude oil. Husky's realized refining margins are accounted for on a FIFO basis in accordance with International Financial Reporting Standards ("IFRS").

Sensitivity Analysis

The following table is indicative of the impact on earnings before income taxes and net earnings from changes in certain key variables in the fourth quarter of 2014. The table below reflects what the effect would have been on the financial results for the fourth quarter of 2014 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the fourth quarter of 2014. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	**2014 Fourth Quarter Average**	Increase	Effect on Earnings before Income Taxes(1)		Effect on Net Earnings(1)	
			($ millions)	*($/share)(2)*	*($ millions)*	*($/share)(2)*
WTI benchmark crude oil price(3)(4)	**73.15**	*U.S. $1.00/bbl*	**88**	**0.09**	**65**	**0.07**
NYMEX benchmark natural gas price(5)	**4.00**	*U.S. $0.20/mmbtu*	**39**	**0.04**	**28**	**0.03**
WTI/Lloyd crude blend differential(6)	**14.14**	*U.S. $1.00/bbl*	**(26)**	**(0.03)**	**(20)**	**(0.02)**
Canadian light oil margins	**0.049**	*Cdn $0.005/litre*	**15**	**0.01**	**11**	**0.01**
Asphalt margins	**22.92**	*Cdn $1.00/bbl*	**11**	**0.01**	**8**	**0.01**
New York Harbour 3:2:1 crack spread	**16.09**	*U.S. $1.00/bbl*	**52**	**0.05**	**31**	**0.03**
Exchange rate (U.S. $ per Cdn $)(3)(7)	**0.881**	*U.S. $0.01*	**(69)**	**(0.07)**	**(51)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.7 million common shares outstanding as of December 31, 2014.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Excludes impact on asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

3. Strategic Plan

Husky's strategy is to maintain and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward thermal developments and resource plays, while advancing its three major growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). 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), 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).

4. Key Growth Highlights

The 2014 Capital Program built on the momentum achieved over the past three years with respect to repositioning the Heavy Oil and Western Canada foundation by accelerating heavy oil production growth and repositioning Western Canada to focus on oil and liquids-rich natural gas resource plays and advancing Husky's three major growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

4.1 Upstream

Western Canada (Excluding Heavy Oil and Oil Sands)

Western Canada Resource Play Development

Liquids-Rich Natural Gas Resource Plays

In the fourth quarter of 2014, 15 wells (gross) were drilled and 14 wells (gross) were completed in key plays across the liquids-rich natural gas portfolio.

Liquids-Rich Natural Gas Plays - Drilling and Completion Activity[1][2]		Three months ended Dec. 31, 2014		Year ended Dec. 31, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	9	6	31	23
Duvernay	Kaybob, Alberta	—	—	—	2
Wilrich	Kakwa, Alberta	4	4	10	7
Strachan Cardium	Rocky Mountain House, Alberta	2	2	9	11
Bivouac Muskwa	Bivouac, B.C.	—	2	1	2
Total Gross		15	14	51	45
Total Net		14	11	41	36

[1] *Excludes service/stratigraphic test wells for evaluation purposes.*
[2] *Drilling activity includes operated and non-operated wells.*

In the Ansell multi-zone liquids-rich natural gas resource play, nine horizontal wells (gross) were drilled and six horizontal wells (gross) were completed in the fourth quarter of 2014. Average production from the play was approximately 18,700 boe/day in the fourth quarter of 2014.

Development continued on the Strachan liquids-rich natural gas resource play near Rocky Mountain house with two wells (gross) drilled and two wells (gross) completed in the fourth quarter of 2014. Production is in line with expectations.

Oil Resource Plays

In the fourth quarter of 2014, five horizontal wells (gross) were drilled and nine horizontal wells (gross) were completed across key plays in the oil resource project portfolio.

Oil Resource Plays - Drilling and Completion Activity[1]		Three months ended Dec. 31, 2014		Year ended Dec. 31, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	—	—	7	7
Lower Shaunavon	S.W. Saskatchewan	—	—	—	2
Viking[2]	Alberta and S.W. Saskatchewan	5	4	27	25
N.Cardium	Wapiti, Alberta	—	5	6	13
Muskwa	Rainbow Region	—	—	1	2
Total Gross		5	9	41	49
Total Net		3	7	36	44

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*
(2) *Viking is comprised of project activity at Redwater in central Alberta, Alliance in southeast Alberta and drilling in southwest Saskatchewan.*

Conventional Oil and Gas

Approximately five wells (gross) were drilled and three wells (gross) were completed in the fourth quarter of 2014 in the conventional oil and gas portfolio.

Heavy Oil

The 3,500 bbls/day Sandall heavy oil thermal development began producing crude oil in the first quarter of 2014 ahead of schedule. Production response continues to be strong with oil rates averaging 5,600 bbls/day in the fourth quarter of 2014.

Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the third quarter of 2015.

Site clearing, detailed engineering and module fabrication continued at the two 10,000 bbls/day Edam East and Vawn and the 3,500 bbls/day Edam West thermal developments with first production from all three projects expected in the second half of 2016.

Additional drilling commenced at McMullen in December 2014 which continued into the first quarter of 2015 to further progress the play.

Total production from the Company's existing heavy oil thermal developments averaged approximately 45,100 bbls/day in the fourth quarter of 2014.

Twenty-eight horizontal heavy oil wells (gross) and 28 Cold Heavy Oil Production with Sand ("CHOPS") wells (gross) were drilled during the fourth quarter of 2014.

Asia Pacific Region

China

Block 29/26

Production from the Liwan 3-1 gas field continued to increase in the fourth quarter of 2014. Tie-in of the Liuhua 34-2 field single production well into the Liwan 3-1 field deepwater infrastructure was completed and commissioned and first gas was achieved in December 2014. Market opportunities for the sale of gas and liquids from the third deepwater field, Liuhua 29-1 continue to be assessed.

Offshore Taiwan

Processing and analysis of the two-dimensional seismic survey data on the Company's offshore Taiwan block is in progress.

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block. Work related to the BD field engineering, procurement, installation and construction contract is ongoing and approximately 29 percent complete. The contract for the construction and lease of an FPSO vessel was signed in December 2014.

Tender plans for the MDA and MBH development projects were approved by SKK Migas, the Indonesia oil and gas regulator, and the tendering process is in progress. The Gas Sales Agreement for the first tranche of gas from this development is complete and awaiting final approval from the regulator.

Anugerah

Exploration work, including planning for a three-dimensional seismic survey covering the Anugerah contract area, is in progress.

Oil Sands

Sunrise Energy Project

Plant 1A of the Sunrise Energy Project began injecting steam into the reservoir in December 2014. First oil is anticipated towards the end of the first quarter of 2015. At Plant 1B, all welding is substantially completed, and construction activities are focused on completing electrical, instrumentation and insulation work. Plant 1B is on track to begin steaming in mid-2015.

Atlantic Region

White Rose Field and Satellite Extensions

Development drilling has commenced on the first production wells for the South White Rose Extension, with first oil anticipated in mid-2015.

The Hibernia-formation well at the North Amethyst field is scheduled to begin production in the third quarter of 2015. Production from the well, originally planned to commence in the fourth quarter of 2014, has been delayed due to rig scheduling.

Hearings for the public review of the application for a wellhead platform to facilitate full field development at West White Rose were held during 2014. Husky has deferred a final investment decision on the project.

Atlantic Exploration

The semi-submersible drilling rig West Hercules commenced an 18-month exploration and appraisal program in the Bay du Nord discovery area offshore Newfoundland and Labrador in November 2014.

Drilling of an exploration well on the Aster prospect in the Flemish Pass Basin commenced on December 19, 2014, and results are being evaluated.

Infrastructure and Marketing

The Hardisty terminal expansion project includes multiple initiatives intended to increase pipeline connectivity and blending capacity that would expand Husky's terminalling business, support upstream production growth and provide additional flexibility through the inclusion of the Company's production in various crude streams. Construction of the two 300,000-barrel storage tanks and the expanded piping and blending infrastructure is complete. The project is now in the commissioning phase with start up expected in the first quarter of 2015.

The Saskatchewan Gathering System is undergoing an extension and capacity expansion into Lloydminster in order to accommodate planned production from the Rush Lake, Edam East, Vawn and Edam West thermal developments.

4.2 Downstream

Husky Lima, Ohio Refinery

Front-end engineering design ("FEED") on the Company’s feedstock flexibility project is now complete. Detailed engineering is ongoing, and long lead equipment has been ordered. The project is expected to give the refinery flexibility to take up to 40,000 bbls/day of Western Canadian heavy oil while overall nameplate capacity would remain unchanged at 160,000 bbls/day.

BP-Husky Toledo, Ohio Refinery

The Hydrotreater Recycle Gas Compressor Project was completed in the fourth quarter of 2014. The project is expected to improve operational integrity and plant performance.

5. Results of Operations

5.1 Upstream

Total Upstream net earnings include results from both the Exploration and Production operations and the Infrastructure and Marketing operations. Net earnings on a combined basis reflected weaker Exploration and Production earnings compared to the same period in 2013 primarily due to impairment charges and increased exploration and evaluation activity, combined with weaker realized crude oil prices in the fourth quarter of 2014. The decreases were partially offset by higher production and higher realized natural gas prices.

Exploration and Production

Exploration and Production Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2014**	2013	**2014**	2013
Gross revenues	**1,890**	1,734	**8,634**	7,333
Royalties	**(178)**	(215)	**(1,030)**	(864)
Net revenues	**1,712**	1,519	**7,604**	6,469
Purchases, operating, transportation and administrative expenses	**582**	575	**2,521**	2,347
Depletion, depreciation, amortization and impairment	**1,553**	791	**3,434**	2,515
Exploration and evaluation expenses	**113**	28	**214**	246
Other expenses (income)	**(37)**	(34)	**98**	78
Income tax expense (recovery)	**(125)**	41	**345**	331
Net earnings (loss)	**(374)**	118	**992**	952

Fourth Quarter

Excluding an after-tax impairment charge of $622 million and $204 million recognized in the fourth quarter of 2014 and 2013, respectively, Exploration and Production net earnings in the fourth quarter of 2014 were $248 million compared with $322 million in the fourth quarter of 2013.

Production increased by 51.3 mboe/day in the fourth quarter of 2014 compared to the same period in 2013. The increase in production was primarily due to new natural gas and NGL production from the Liwan Gas Project, new heavy crude oil production from the Sandall heavy oil thermal development which began producing in the first quarter of 2014 and higher production from Terra Nova where a turnaround was completed in the fourth quarter of 2013. These increases were partially offset by natural reservoir declines from mature properties in Western Canada and the Atlantic Region.

The average realized price for crude oil, NGL and bitumen in the fourth quarter of 2014 was $63.96/bbl compared to $73.06/bbl during the same period in 2013, a 12 percent decrease, due to lower Brent and WTI market prices partially offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. Realized natural gas prices averaged $6.37/mcf in the fourth quarter of 2014 compared to $3.30/mcf in the same period in 2013, an increase of 93 percent, primarily due to higher realized contract prices on production from the Liwan Gas Project and higher natural gas benchmark prices in Canada.

Twelve Months

Excluding an after-tax impairment charge of $622 million and $204 million recognized in 2014 and 2013, respectively, Exploration and Production net earnings in 2014 were $1,614 million, an increase of $458 million compared to 2013 primarily due to increased crude oil and natural gas production, higher realized commodity prices in the first half of 2014 and lower exploration and evaluation expenses partially offset by lower realized crude oil prices due to declines in market benchmarks in the second half of 2014. During 2014, the average realized price for crude oil, NGL and bitumen was $81.10/bbl compared to $78.12/bbl in 2013, an increase of 4 percent. During 2014, the average realized natural gas price was $5.99/mcf compared to $3.19/mcf in 2013, an increase of 88 percent due to the same factors which impacted the fourth quarter of 2014.

Average Sales Prices Realized	Three months ended Dec. 31, 2014	2013	Year ended Dec. 31, 2014	2013
Crude oil and NGL *($/bbl)*				
Light crude oil & NGL	**71.77**	101.95	**96.70**	102.35
Medium crude oil	**64.60**	67.86	**80.69**	74.29
Heavy crude oil	**58.86**	56.51	**71.91**	63.44
Bitumen	**58.21**	54.08	**70.57**	61.68
Total crude oil and NGL average	**63.96**	73.06	**81.10**	78.12
Natural gas average *($/mcf)*	**6.37**	3.30	**5.99**	3.19
Total average *($/boe)*	**55.53**	58.55	**67.38**	61.96

The price realized for Western Canada crude oil in the fourth quarter of 2014 reflected lower WTI prices partially offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. The premium to WTI realized for offshore production reflects Brent prices. Natural gas prices reflect increasing Canadian benchmark prices combined with favourable prices received at the Liwan Gas Project.

Daily Gross Production	Three months ended Dec. 31, 2014	2013	Year ended Dec. 31, 2014	2013
Crude Oil and NGL *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**31.2**	30.2	**30.1**	29.7
Medium crude oil	**19.7**	23.4	**21.5**	23.2
Heavy crude oil	**77.5**	75.9	**76.8**	74.5
Bitumen[(1)]	**55.7**	46.7	**54.6**	47.7
	184.1	176.2	**183.0**	175.1
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**35.2**	39.2	**38.6**	39.3
Terra Nova – light crude oil	**8.2**	1.6	**6.0**	4.8
	43.4	40.8	**44.6**	44.1
Asia Pacific Region				
Light crude oil & NGL[(2)]	**15.2**	7.3	**9.0**	7.3
	242.7	224.3	**236.6**	226.5
Natural gas *(mmcf/day)*				
Western Canada	**521.3**	503.8	**506.8**	512.7
Asia Pacific Region[(2)]	**180.2**	—	**114.2**	—
	701.5	503.8	**621.0**	512.7
Total *(mboe/day)*	**359.6**	308.3	**340.1**	312.0

(1) Bitumen production includes heavy oil thermal average daily gross production of 45.1 mbbls/day and 43.8 mbbls/day for the three months and year ended December 31, 2014, respectively.

(2) Reported production volumes include Husky's net working interest production from the Liwan Gas Project (49 percent) and an incremental share of production volumes which are allocated to Husky until full project exploration cost recovery is attained.

Crude Oil and NGL Production

Fourth Quarter

Crude oil and NGL production in the fourth quarter of 2014 increased by 18.4 mbbls/day or 8 percent compared to the same period in 2013. The increase was primarily due to new NGL production from the Liwan Gas Project, increased liquids production at the Ansell liquids-rich natural gas resource play, new heavy oil thermal production at the Sandall heavy oil thermal development and higher production from Terra Nova where a turnaround was completed in the fourth quarter of 2013 partially offset by natural reservoir declines from mature properties in Western Canada and the Atlantic Region.

Twelve Months

Crude oil and NGL production in 2014 increased by 10.1 mbbls/day or 4 percent compared to 2013 primarily due to the same factors which impacted the fourth quarter.

Natural Gas Production

Fourth Quarter

Natural gas production in the fourth quarter of 2014 increased by 197.7 mmcf/day or 39 percent compared to the same period in 2013 primarily due to new production from the Liwan Gas Project and increased production at the Ansell liquids-rich natural gas resource play.

Twelve Months

Natural gas production in 2014 increased by 108.3 mmcf/day or 21 percent compared to 2013 primarily due to the same factors impacting the fourth quarter offset by natural reservoir declines in Western Canada mature properties as capital investment is being directed oil and liquids-rich natural gas developments.

2014 Production Guidance

The following table shows actual daily production for the year ended December 31, 2014 and the year ended December 31, 2013, as well as the previously issued production guidance for 2014.

		Actual Production	
	2014 Guidance	**Year ended December 31, 2014**	Year ended December 31, 2013
Crude oil, NGL and Asia Pacific Gas *(mbbls/day)*			
Light / Medium crude oil & NGL	110 – 115	**105**	104
Heavy crude oil	125 – 130	**131**	122
Natural Gas Asia Pacific Region *(mboe/day)*	25 – 30	**19**	—
	260 – 275	**255**	226
Natural Gas Canada *(mmcf/day)*	420 – 480	**507**	513
Total *(mboe/day)*	330 – 355	**340**	312

Royalties

Fourth Quarter

In the fourth quarter of 2014, royalty rates as a percentage of gross revenues averaged 10 percent compared to 13 percent in the same period in 2013. Royalty rates in Western Canada averaged 11 percent in the fourth quarter of 2014 compared to 12 percent in the same period in 2013. Royalty rates for the Atlantic Region averaged 8 percent in the fourth quarter of 2014 compared to 14 percent in the same period in 2013 resulting from higher eligible royalty expenses, lower realized commodity prices and a government reassessment credit received in the fourth quarter of 2014. Royalty rates in the Asia Pacific Region averaged 5 percent in the fourth quarter of 2014 compared to 24 percent in the same period in 2013 due to lower royalty rates associated with production from the Liwan Gas Project which started producing at the end of the first quarter of 2014.

Twelve Months

Royalty rates averaged 12 percent of gross revenues in both 2014 and 2013. Royalty rates in Western Canada averaged 12 percent in both 2014 and 2013. Royalty rates for the Atlantic Region averaged 17 percent in 2014 compared to 13 percent in 2013 due to Tier 1 and super royalty rates being reached at the North Amethyst and West White Rose Satellite Extensions. Royalty rates in the Asia Pacific Region averaged 8 percent in 2014 compared to 24 percent in 2013 due to the same factors which impacted the fourth quarter.

Operating Costs

	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2014**	2013	**2014**	2013
Western Canada	**437**	428	**1,819**	1,745
Atlantic Region	**54**	57	**218**	201
Asia Pacific	**34**	10	**82**	31
Total	**525**	495	**2,119**	1,977
Unit operating costs *($/boe)*	**15.07**	16.31	**16.12**	16.28

Fourth Quarter

Operating costs in Western Canada averaged $16.44/boe in the fourth quarter of 2014 compared to $16.55/boe in the same period in 2013. The decrease was primarily attributable to higher production volumes in the fourth quarter of 2014 compared to the same period in 2013 while overall costs were comparable. Higher energy costs were offset by the impact of increasing production from lower unit cost thermal projects.

Operating costs in the Atlantic Region averaged $13.55/boe in the fourth quarter of 2014 compared to $15.19/boe in the same period in 2013. The decrease was primarily due to higher production volumes in the fourth quarter of 2014 compared to the same period in 2013 when a turnaround was completed at the Terra Nova field.

Operating costs in the Asia Pacific Region averaged $7.67/boe in the fourth quarter of 2014 compared to $13.63/boe in the same period in 2013. The decrease was primarily due to production from the Liwan Gas Project which commenced at the end of the first quarter of 2014.

Twelve Months

Total Exploration and Production operating costs were $2,119 million in 2014 compared to $1,977 million in 2013. Operating costs in Western Canada averaged $17.39/boe in 2014 compared to $17.05/boe in 2013 primarily due to increased natural gas prices and maintenance activities partially offset by lower unit operating cost thermal projects. Operating costs in the Atlantic Region averaged $13.38/boe in 2014 compared to $12.47/boe in 2013 primarily due to higher logistics and ice management costs and the completion of maintenance turnarounds on the SeaRose FPSO. Operating costs in the Asia Pacific Region averaged $8.06/boe in 2014 compared to $11.39/boe in 2013 due to the same factors which impacted the fourth quarter.

Exploration and Evaluation Expenses

	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2014**	2013	**2014**	2013
Seismic, geological and geophysical	**32**	31	**111**	133
Expensed drilling[(1)]	**31**	(5)	**45**	102
Expensed land	**50**	2	**58**	11
Exploration and evaluation expenses	**113**	28	**214**	246

[(1)] *Expensed drilling in the fourth quarter of 2013 included a recovery of Atlantic Region drilling costs previously written-off in 2012.*

Fourth Quarter

Exploration and evaluation expenses in the fourth quarter of 2014 were $113 million compared to $28 million in the fourth quarter of 2013. Expensed land in the fourth quarter of 2014 included exploration and evaluation assets in Western Canada. Expensed drilling in the fourth quarter of 2014 was related to drilling activity in Canada.

Twelve Months

Exploration and evaluation expenses in 2014 were $214 million compared to $246 million in 2013. The increase in expensed land in 2014 was primarily due to the same factors which impacted the fourth quarter. Expensed drilling in 2013 included costs related to the winter program at the Slater River Canol shale project, as well as drilling costs associated with activities in the Atlantic Region. Seismic, geological and geophysical costs in 2013 included a one-time work commitment penalty in the Atlantic Region.

Depletion, Depreciation, Amortization ("DD&A") and Impairment

Fourth Quarter

During the fourth quarter of 2014, the Company recognized a pre-tax impairment charge of $838 million on certain conventional crude oil and natural gas assets located in Western Canada compared to a pre-tax impairment charge of $275 million in the same period of 2013. The impairment charge was the result of lower estimated short and long-term crude oil and natural gas prices.

In the fourth quarter of 2014, total DD&A averaged $21.65/boe compared to $18.22/boe in the fourth quarter of 2013, both excluding impairment charges. The increase in the DD&A rate in the fourth quarter of 2014 compared to the same period in 2013 was primarily attributable to a higher depletion rate per boe on production from the Liwan Gas Project.

Twelve Months

In 2014, total DD&A averaged $20.92/boe compared to $19.67/boe in 2013, both excluding impairment charges. The increased DD&A rate in 2014 was primarily due to the same factors which influenced the fourth quarter.

Exploration and Production Capital Expenditures

In 2014, Upstream Exploration and Production capital expenditures were $4,189 million. Capital expenditures were $2,334 million (56%) in Western Canada including Heavy Oil, $713 million (17%) in Oil Sands, $746 million (18%) in the Atlantic Region and $396 million (9%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1]	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2014**	2013	**2014**	2013
Exploration				
Western Canada	**37**	80	**209**	353
Oil Sands	**—**	—	**5**	—
Atlantic Region	**62**	55	**96**	201
Asia Pacific Region	**5**	14	**16**	21
	104	149	**326**	575
Development				
Western Canada	**559**	744	**2,074**	2,029
Oil Sands	**225**	111	**708**	552
Atlantic Region	**205**	34	**650**	437
Asia Pacific Region	**12**	215	**380**	633
	1,001	1,104	**3,812**	3,651
Acquisitions				
Western Canada	**31**	27	**51**	38
	1,136	1,280	**4,189**	4,264

[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

Western Canada, Heavy Oil and Oil Sands

The following table discloses the number of gross and net exploration and development wells completed in Western Canada, Heavy Oil and Oil Sands during the periods indicated:

	Three months ended Dec. 31,				Year ended Dec. 31,			
Wells Drilled [(1)]	**2014**		2013		**2014**		2013	
(wells)	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**1**	**—**	11	7	**53**	**45**	39	24
Gas	**3**	**1**	7	5	**9**	**5**	19	14
Dry	**3**	**3**	—	—	**3**	**3**	—	—
	7	**4**	18	12	**65**	**53**	58	38
Development								
Oil	**99**	**93**	217	201	**469**	**419**	768	709
Gas	**9**	**8**	15	12	**78**	**68**	68	41
Dry	**2**	**2**	—	—	**3**	**3**	1	—
	110	**103**	232	213	**550**	**490**	837	750
Total	**117**	**107**	250	225	**615**	**543**	895	788

[(1)] *Excludes Service/Stratigraphic test wells for evaluation purposes.*

The Company drilled 543 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2014 resulting in 464 net oil wells and 73 net natural gas wells compared to 788 net wells resulting in 733 net oil wells and 55 net natural gas wells in 2013.

During 2014, Husky invested $2,334 million in exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $2,420 million in 2013. Property acquisitions totalling $51 million were completed in 2014 compared to $38 million in 2013. Oil related exploration and development in 2014 was $392 million compared to $576 million in 2013. Investment in natural gas related exploration and development, primarily liquids-rich, was $502 million in 2014 compared to $596 million in 2013.

In addition, $77 million was spent on production optimization and cost reduction initiatives in 2014 compared to $232 million in 2013. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $752 million in 2014 compared to $349 million in 2013.

Capital expenditures on heavy oil thermal developments, CHOPS drilling and horizontal drilling were $560 million in 2014 compared to $629 million in 2013.

Oil Sands

During 2014, $713 million was invested in Oil Sands projects, compared to $552 million in 2013, primarily on Phase 1 of the Sunrise Energy Project.

Atlantic Region

During 2014, $746 million was invested in Atlantic Region projects, compared to $638 million in 2013, primarily on the continued development of the White Rose Extension projects, including the North Amethyst, West White Rose and South White Rose Extensions.

Asia Pacific Region

During 2014, $396 million was invested in Asia Pacific Region projects, compared to $654 million in 2013, primarily on the continued development of the Liwan Gas Project.

Oil and Gas Reserves

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

Sproule Unconventional Limited ("Sproule"), an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct a full evaluation of Husky's crude oil, natural gas and natural gas products reserves for the Company's Heavy Oil and Gas business unit, excluding the Tucker property.

At December 31, 2014, Husky's proved oil and gas reserves were 1,279 mmboe, up from 1,265 mmboe at the end of 2013. Additions to proved reserves, including acquisitions and divestitures, represent 115 percent excluding economic revisions (111 percent including economic revisions) of 2014 production. Major additions to proved reserves in 2014 included:

- The extension through additional drilling locations at the Sunrise Energy Project that resulted in the booking of an additional 40 mmbbls of bitumen in proved undeveloped reserves;
- Extensions, improved recovery and strong performance in Heavy Oil and Gas thermal projects that resulted in the booking of an additional 36 mmbbls of Bitumen in proved reserves;
- Strong performance from Liwan 3-1 that resulted in the booking of an additional 19 mmboe of natural gas and natural gas liquids in proved developed producing reserves; and
- The extension through additional drilling locations at the Ansell liquids-rich natural gas resource play that resulted in the booking of an additional 10 mmboe of natural gas and natural gas liquids in proved undeveloped reserves.

Reconciliation of Proved Reserves	Crude Oil & NGL *(mmbbls)*	Natural Gas (bcf)	Equivalent Units *(mmboe)*
Proved reserves			
December 31, 2013	827	2,627	1,265
Revision of previous estimate	(6)	163	21
Purchase of reserves in place	3	—	3
Sale of reserves in place	(7)	(1)	(7)
Discoveries, extensions and improved recovery	105	123	125
Economic revision	(1)	(23)	(4)
Production	(86)	(227)	(124)
Proved reserves December 31, 2014	835	2,662	1,279
Proved and probable reserves December 31, 2014	2,570	3,473	3,149
December 31, 2013	2,539	3,528	3,127

Upstream Planned Turnarounds

- Planned turnarounds at the Ansell liquids-rich natural gas resource play and Ram River plant in Western Canada are expected to have an impact of about 4,700 boe/day in the second quarter of 2015.
- Other scheduled third-party shutdowns are expected to impact Western Canada production by approximately 3,300 boe/day in the third quarter of 2015.
- A three-week maintenance shutdown is planned at the Tucker heavy oil thermal project in the second quarter of 2015.
- Partial shut-downs are scheduled at several heavy oil thermal projects to perform routine maintenance, with an estimated aggregate impact of 8,000 bbls/day in June 2015.
- An 18-day turnaround on the SeaRose FPSO vessel is scheduled for the third quarter of 2015.
- A 28-day turnaround on the Terra Nova FPSO is expected to start in the second quarter of 2015. A concurrent 90-day inspection of the vessel's main power generator is expected to further curtail production.

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke production. The Company owns extensive infrastructure in Western Canada, including pipeline and storage facilities, and has access to capacity on third party pipelines and storage facilities in both Canada and the United States.

Infrastructure and Marketing Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Infrastructure gross margin	**34**	19	**146**	130
Marketing and other gross margin	**22**	76	**70**	312
Gross margin	**56**	95	**216**	442
Operating and administrative expenses	**13**	5	**40**	33
Depreciation and amortization	**6**	2	**25**	20
Other income	**(1)**	(2)	**(2)**	(3)
Income taxes	**10**	23	**39**	100
Net earnings	**28**	67	**114**	292
Commodity trading volumes managed *(mboe/day)*	**245.7**	184.5	**252.3**	174.5

Fourth Quarter

Infrastructure and Marketing net earnings in the fourth quarter of 2014 decreased by $39 million compared to the same period in 2013 as a result of narrowing product price differentials between Canada and the United States. The increase to commodity trading volumes managed relates primarily to additional pipeline capacity.

Twelve Months

Infrastructure and Marketing net earnings in 2014 decreased by $178 million compared to the same period in 2013 primarily due to the same factors which impacted the fourth quarter of 2014.

Infrastructure and Marketing Capital Expenditures

In 2014, Infrastructure and Marketing capital expenditures totalled $211 million compared to $96 million in 2013 primarily related to the Hardisty terminal expansion project and the extension and capacity expansion of the Saskatchewan Gathering System into Lloydminster.

5.2 Downstream

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing operations. Net earnings on a combined basis reflected weaker U.S. Refining and Marketing earnings as falling commodity prices led to inventory impairments, FIFO losses and weaker Upgrader net earnings primarily resulting from lower upgrading differentials.

Upgrader

Upgrader Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Gross revenues	**475**	484	**2,212**	2,023
Gross margin	**95**	122	**536**	645
Operating and administrative expenses	**50**	47	**189**	168
Depreciation and amortization	**29**	25	**108**	96
Other expenses (income)	**3**	(22)	**12**	(20)
Income taxes	**4**	19	**59**	104
Net earnings	**9**	53	**168**	297
Upgrader throughput *(mbbls/day)*[(1)]	**76.3**	65.6	**72.7**	66.1
Synthetic crude oil sales *(mbbls/day)*	**54.8**	52.0	**53.3**	50.5
Upgrading differential *($/bbl)*	**14.96**	26.63	**21.80**	29.14
Unit margin *($/bbl)*	**18.84**	25.50	**27.55**	34.99
Unit operating cost *($/bbl)*[(2)]	**6.84**	7.79	**6.78**	6.96

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

Fourth Quarter

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

Upgrader net earnings decreased by $44 million in the fourth quarter of 2014 compared to the same period in 2013 primarily due to lower realized upgrading differentials partially offset by higher throughput and sales volumes compared to the same period in 2013 when a major planned turnaround was ongoing.

During the fourth quarter of 2014, the upgrading differential averaged $14.96/bbl, a decrease of $11.67/bbl or 44 percent compared to the same period in 2013. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in the upgrading differential was attributable to lower realized prices for Husky Synthetic Blend partially offset by lower heavy oil feedstock costs. The average price for Husky Synthetic Blend in the fourth quarter of 2014 was $79.88/bbl compared to $92.08/bbl in the same period in 2013.

Twelve Months

Upgrader net earnings in 2014 decreased by $129 million compared to 2013. The decrease in net earnings was primarily due to lower realized upgrading differentials as realized prices for Husky Synthetic Blend were offset by higher feedstock costs. Higher energy costs and maintenance contributed to the increase in operating and administrative expenses and a recovery of upside interest, associated with the remaining payment obligation to Natural Resources Canada and the Alberta Department of Energy, recognized in 2013 contributed to the increase in other expenses in 2014 compared to 2013. The average price for Husky Synthetic Blend in 2014 was $101.38/bbl compared to $100.59/bbl in the same period in 2013.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	Three months ended Dec. 31, 2014	2013	Year ended Dec. 31, 2014	2013
Gross revenues	**945**	1,288	**4,020**	3,737
Gross margin				
Fuel	**37**	34	**147**	140
Refining	**49**	54	**251**	175
Asphalt	**63**	58	**246**	233
Ancillary	**14**	13	**57**	55
	163	159	**701**	603
Operating and administrative expenses	**81**	65	**307**	253
Depreciation and amortization	**27**	23	**102**	90
Other expenses	**1**	2	**5**	—
Income taxes	**13**	17	**73**	66
Net earnings	**41**	52	**214**	194
Number of fuel outlets(1)	**490**	504	**497**	509
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**8.1**	7.9	**8.0**	8.1
Fuel sales per retail outlet *(thousands of litres/day)*	**13.5**	13.8	**13.4**	13.5
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**11.7**	12.0	**11.7**	10.3
Lloydminster Refinery *(mbbls/day)*	**29.0**	28.4	**28.8**	26.4
Ethanol production *(thousands of litres/day)*	**786.0**	776.4	**780.7**	742.4

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

Fourth Quarter

Higher fuel gross margins in the fourth quarter of 2014 compared to the same period in 2013 were primarily due to higher gasoline margins.

Lower refining gross margins in the fourth quarter of 2014 compared to the same period in 2013 were primarily due to lower Canadian market crack spreads as lower realized sales prices were only partially offset by lower feedstock costs.

Higher asphalt gross margins in the fourth quarter of 2014 compared to the same period in 2013 were primarily due to lower feedstock costs and increased sales volumes of asphalt and drilling fluids.

Higher energy costs contributed to the increase in operating and administrative expenses during the fourth quarter of 2014 compared to the same period in 2013.

Twelve Months

During 2014, Canadian Refined Products earnings increased by $20 million compared to 2013 primarily due to higher refining margins resulting from higher refinery throughput and lower feedstock costs at the ethanol plants, partially offset by increased operating costs resulting from higher energy costs.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Gross revenues	**2,504**	2,690	**10,663**	10,728
Gross refining margin	**(151)**	147	**722**	1,182
Operating and administrative expenses	**123**	102	**481**	424
Depreciation and amortization	**68**	60	**268**	233
Other expenses	**1**	1	**3**	3
Income taxes	**(127)**	(5)	**(11)**	183
Net earnings (loss)	**(216)**	(11)	**(19)**	339
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**162.8**	151.8	**141.6**	149.4
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**63.8**	66.3	**63.2**	65.0
Refining margin *(U.S. $/bbl crude throughput)*	**(6.62)**	6.94	**9.37**	15.06
Refinery inventory *(mmbbls)*[(1)]	**10.8**	10.3	**10.8**	10.3

[(1)] *Included in refinery inventory is feedstock and refined products.*

Fourth Quarter

U.S. Refining and Marketing net earnings decreased in the fourth quarter of 2014 compared to the same period in 2013 as falling commodity prices led to FIFO losses and write-downs of inventory to net realizable value partially offset by higher throughput at the Lima Refinery. The after-tax impact on U.S. Refining and Marketing from the write-down of inventories to net realizable value was $128 million in the fourth quarter of 2014. Excluding this provision, the Company's U.S. refining margin for the fourth quarter of 2014 was U.S. $2.39/bbl reflecting significant FIFO losses due to rapidly declining crude oil prices.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were higher. The estimated FIFO impact was a decrease in net earnings of approximately $130 million in the fourth quarter of 2014 compared to a decrease in net earnings of approximately $94 million in the same period in 2013.

In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10 percent to 15 percent of other products which are sold at discounted market prices compared to gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Twelve Months

Net earnings in 2014 decreased by $358 million compared to 2013 primarily due to the same factors which impacted the fourth quarter combined with lower Chicago 3:2:1 market crack spreads and lower throughput resulting from planned maintenance at the Lima Refinery in the first and second quarters of 2014. The after-tax impact on U.S. Refining and Marketing from the write-down of inventories to net realizable value was $128 million in 2014. Excluding inventory write-downs, the Company's U.S. refining margin for 2014 was U.S. $11.83/bbl including FIFO losses. The estimated FIFO impact was a reduction in net earnings of approximately $108 million in 2014 compared to a reduction in net earnings of approximately $18 million in 2013.

Downstream Capital Expenditures

In 2014, Downstream capital expenditures totalled $510 million compared to $534 million in 2013. In Canada, capital expenditures of $136 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. At the Lima Refinery, $260 million was spent primarily on the feedstock flexibility project and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $114 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

A turnaround at the BP-Husky Toledo Refinery is scheduled to commence in the third quarter of 2015.

5.3 Corporate

Corporate Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions) income (expense)	**2014**	2013	**2014**	2013
Selling, general and administrative expenses	**(91)**	(90)	**(139)**	(217)
Depreciation and amortization	**(21)**	(17)	**(73)**	(51)
Other income	**—**	—	**5**	17
Foreign exchange gains	**35**	12	**81**	21
Interest income (expense)	**(16)**	9	**(64)**	—
Income tax recovery (expense)	**2**	(16)	**(21)**	(15)
Net loss	**(91)**	(102)	**(211)**	(245)

Fourth Quarter

The Corporate segment reported a loss of $91 million in the fourth quarter of 2014 compared to a loss of $102 million in the same period in 2013. Interest expense increased by $25 million in the fourth quarter of 2014 compared to the same period in 2013 due to a decrease in the amount of capitalized interest related to production being achieved at the Liwan Gas Project and a decrease in interest income associated with the Sunrise Oil Sands Partnership contribution receivable. Foreign exchange gains increased by $23 million in the fourth quarter of 2014 compared to the same period in 2013 due to the weakening of the Canadian dollar against the U.S. dollar which positively impacted the translation of the Company's foreign currency denominated working capital.

Twelve Months

In 2014, the Corporate segment reported a loss of $211 million compared to a loss of $245 million in 2013. Selling, general, and administrative expenses decreased in 2014 compared to 2013 primarily due to lower stock-based compensation expense associated with a decrease in the Company's share price in 2014. Interest expense increased in 2014 compared to 2013 primarily due to the same factors which impacted the fourth quarter of 2014.

Foreign Exchange Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(10)**	—	**7**	(11)
Gains on contribution receivable	**—**	6	**6**	27
Gains on non-cash working capital	**17**	14	**42**	33
Other foreign exchange gains (losses)	**28**	(8)	**26**	(28)
Net foreign exchange gains	**35**	12	**81**	21
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.892**	U.S. $0.972	**U.S. $0.940**	U.S. $1.005
At end of period	**U.S. $0.862**	U.S. $0.940	**U.S. $0.862**	U.S. $0.940

Included in other foreign exchange gains (losses) are realized and unrealized foreign exchange gains (losses) on working capital and intercompany financing. The foreign exchange gains (losses) on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period.

Consolidated Income Taxes

Consolidated income taxes in the fourth quarter of 2014 was a recovery of $227 million compared to an expense of $111 million in the same period in 2013 resulting in an effective tax rate of 27 percent in the fourth quarter of 2014 compared to 39 percent in the same period in 2013. The effective tax rate was lower in the fourth quarter of 2014 compared to the same period in 2013 primarily due to a recovery of non-deductible stock-based compensation recorded in the fourth quarter of 2014 compared to an expense recorded in 2013.

	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2014**	2013	**2014**	2013
Income taxes as reported	**(227)**	111	**526**	799
Cash taxes paid	**135**	81	**661**	433

Corporate Capital Expenditures

In 2014, Corporate capital expenditures were $113 million compared to $134 million in 2013 and were primarily related to computer hardware and software and leasehold improvements.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the fourth quarter of 2014, Husky funded its capital programs and dividend payments through cash generated from operating activities, cash on hand, the issuance of commercial paper and the issuance of preferred shares. At December 31, 2014, Husky had total debt of $5,292 million, partially offset by cash on hand of $1,267 million, for $4,025 million of net debt compared to $3,022 million of net debt at December 31, 2013. At December 31, 2014, the Company had $2,792 million of unused credit facilities of which $2,335 million are long-term committed credit facilities and $457 million are short-term uncommitted credit facilities. In addition, the Company had $2.75 billion in unused capacity under its December 2012 Canadian universal short form base shelf prospectus and U.S. $2.25 billion in unused capacity under its October 2013 U.S. universal short form base shelf prospectus. The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. Refer to Section 6.2.

Cash Flow Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except ratios)	**2014**	2013	**2014**	2013
Cash flow				
Operating activities	**1,584**	829	**5,585**	4,645
Financing activities	**205**	(257)	**(6)**	(846)
Investing activities	**(1,444)**	(1,084)	**(5,423)**	(4,722)
Financial Ratios[1]				
Debt to capital employed *(percent)*[2]			**20.5**	17.0
Debt to cash flow *(times)*[3][4]			**1.0**	0.8
Corporate reinvestment ratio *(percent)*[3][5]			**101**	108
Interest coverage ratios on long-term debt only[3][6]				
Earnings			**6.7**	11.2
Cash flow			**23.6**	22.4
Interest coverage ratios on total debt[3][7]				
Earnings			**6.6**	11.3
Cash flow			**23.2**	22.6

(1) *Financial ratios constitute non-GAAP measures. Refer to Section 11.*
(2) *Debt to capital employed is equal to long-term debt, long-term debt due within one year and commercial paper divided by capital employed.*
(3) *Calculated for the 12 months ended for the dates shown.*
(4) *Debt to cash flow (times) is equal to long-term debt, long-term debt due within one year and commercial paper divided by cash flow from operations.*
(5) *Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations.*
(6) *Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow – operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*
(7) *Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow – operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized interest. Total debt includes long-term debt, the current portion of long-term debt and commercial paper.*

Cash Flow from Operating Activities

Fourth Quarter

In the fourth quarter of 2014, cash flow generated from operating activities was $1,584 million compared to $829 million in the same period in 2013. The increase in cash flow generated from operating activities resulted primarily from a decrease in non-cash working capital primarily due to the timing of accounts receivable and accounts payable settlements and lower investments in inventory due to falling commodity prices.

Twelve Months

In 2014, cash flow generated from operating activities was $5,585 million compared to $4,645 million in 2013 primarily due to the same factors which influenced the fourth quarter.

Cash Flow from (used for) Financing Activities

Fourth Quarter

In the fourth quarter of 2014, cash flow from financing activities was $205 million compared to cash flow used for financing activities of $257 million in the same period in 2013 primarily resulting from the issuance of Cumulative Redeemable Preferred Shares, Series 3 in the fourth quarter of 2014 and proceeds from the issuance of commercial paper.

Twelve Months

Cash flow used for financing activities was $6 million in 2014 compared to $846 million in 2013 primarily due to the same factors which impacted the fourth quarter of 2014.

Cash Flow used for Investing Activities

Fourth Quarter

In the fourth quarter of 2014, cash flow used for investing activities was $1,444 million compared to $1,084 million in the same period in 2013. Cash invested in both periods was primarily for capital expenditures.

Twelve Months

Cash flow used for investing activities was $5,423 million in 2014 compared to $4,722 million in 2013. Cash invested in both periods was primarily for capital expenditures.

6.2 Sources of Capital

Husky funds its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, cash on hand, the issuance of long-term debt, borrowings under committed and uncommitted credit facilities, the issuance of short-term commercial paper and the issuance of equity. The Company also maintains access to sufficient capital via debt markets commensurate with its balance sheet. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2014, working capital deficiency was $1,314 million compared to working capital of $754 million at December 31, 2013. The decrease in working capital is primarily due to the reclassification of the BP-Husky Toledo Refinery contribution payable from long-term to short-term to reflect the repayment scheduled in 2015.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in Canada up to and including January 30, 2015. During the fourth quarter of 2014, the Company issued $250 million of Cumulative Redeemable Preferred Shares, Series 3 under the Canadian Shelf Prospectus resulting in unused capacity of $2.75 billion at December 31, 2014.

During the first quarter of 2014, the Company increased the limit of one of its operating lines from $50 million to $100 million. At December 31, 2014, Husky had unused short and long-term credit facilities totalling $2.8 billion. A total of $188 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit and $895 million of the Company's long-term borrowing credit facilities was used in support of commercial paper.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at December 31, 2014.

On October 31, 2013 and November 1, 2013, Husky filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and the U.S. Securities and Exchange Commission, respectively, 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 November 30, 2015.

On March 17, 2014, the Company issued U.S. $750 million of 4 percent notes due April 15, 2024 pursuant to the U.S. Shelf Prospectus. 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 the date of repayment.

On June 19, 2014, the $1.6 billion revolving syndicated credit facility previously set to expire on August 31, 2014 was increased to $1.63 billion, and its maturity was extended to June 19, 2018.

On September 15, 2014, the Company launched a commercial paper program in Canada. The program 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 for commercial paper outstanding as at December 31, 2014 was 1.24 percent.

On December 9, 2014, the Company issued 10 million Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $250 million, by way of a prospectus supplement dated December 2, 2014, under the Canadian Shelf Prospectus. Net proceeds after share issue costs were $243 million. Holders of the Series 3 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.5 percent annually for the initial period ending December 31, 2019 as declared by the Company. 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.

Capital Structure

	December 31, 2014	
($ millions)	Outstanding	Available[1]
Total debt	5,292	2,792
Common shares, preferred shares, retained earnings and other reserves	20,575	

[1] *Available long-term debt includes committed and uncommitted credit facilities.*

6.3 Contractual Obligations and Commercial Commitments

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

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Long-term debt and interest on fixed rate debt	537	2,619	3,065	6,221
Operating leases	115	918	1,019	2,052
Firm transportation agreements	351	1,317	3,275	4,943
Unconditional purchase obligations[1]	2,468	505	329	3,302
Lease rentals and exploration work agreements	321	468	1,219	2,008
Asset retirement obligations[2]	95	558	14,920	15,573
Total	3,887	6,385	23,827	34,099

[1] *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.*
[2] *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

The Company updated its estimates for Asset Retirement Obligations ("ARO") as outlined in Note 11 of the Condensed Interim Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $12.3 billion as at December 31, 2013 to $15.5 billion as at December 31, 2014 due to increased cost estimates and asset growth in both the Upstream and Downstream segments and increased estimated time to retirement in the Upstream segment.

The Company is in the process of renegotiating certain purchase, distribution and terminal commitments related to light oil and asphalt products as the existing contracts are approaching expiration.

The Company has entered into new firm transportation agreements in 2014 and future payments on transportation agreements settled in U.S. dollars have been impacted by a weaker Canadian dollar.

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

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

6.4 Off-Balance Sheet Arrangements

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

6.5 Transactions with Related Parties and Major Customers

On May 11, 2009, the Company issued U.S. $251 million aggregate principal amount of 5-year 5.90 percent senior notes to certain management, shareholders, affiliates and directors. Subsequent to this offering, U.S. $122 million of the 5.90 percent notes issued to related parties were sold to third parties. On June 15, 2014, the Company repaid the maturing 5.90 percent notes. As a result, U.S. $133 million was repaid to related parties which included interest of U.S. $4 million. These transactions were measured at fair market value at the date of the transaction and have been carried out on the same terms as applied to unrelated parties.

The Company sells natural gas to and purchases steam from the Meridian cogeneration facility ("Meridian") and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the three months and year ended December 31, 2014, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $19 million and $78 million, respectively. For the three months and year ended December 31, 2014, the amount of steam purchased by the Company from Meridian totalled $6 million and $25 million, respectively. In addition, the Company provides facility services to Meridian which are measured and reimbursed at cost. For the three months and year ended December 31, 2014, the total cost recovery for these services was $2 million and $9 million, respectively.

7. Risk Management and Financial Risks

7.1 Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2013 Annual Information Form.

The Company has processes in place to identify the principal risks of the business and put in place appropriate mitigation to manage such risks where possible. The Company's exposure to operational, political, environmental, financial, liquidity and contract and credit risk has not materially changed since December 31, 2013, as discussed in Husky's 2013 Annual MD&A.

7.2 Financial Risks

The following provides an update on the Company's commodity price, interest rate and foreign exchange risk management.

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production and firm commitments for the purchase or sale of crude oil and natural gas. These contracts are recorded at fair value.

At December 31, 2014, the Company was party to crude oil purchase and sale derivative contracts to mitigate its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company was also party to third party physical natural gas purchase and sale derivative contracts in order to mitigate commodity price fluctuations. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities.

Interest Rate Risk Management

During the first quarter of 2014, the Company discontinued its cash flow hedge with respect to the forward starting interest rate swaps. These forward interest rate swaps were settled and derecognized. Accordingly, the accrued gain in other reserves – hedging, within the Condensed Consolidated Statement of Changes in Shareholders' Equity, is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated. The amortization period is ten years.

At December 31, 2014, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps previously designated as cash flow hedges was $23 million (December 31, 2013 – $37 million), net of tax of $8 million (December 31, 2013 – net of tax of $13 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an addition to finance income of $1 million and $3 million for the three months and year ended December 31, 2014, respectively.

Refer to Note 13 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At December 31, 2014, 84 percent or $3.7 billion of Husky's outstanding long-term debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, 7 percent of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At December 31, 2014, the Company had designated U.S. $2.9 billion denominated debt as a hedge of the Company's net investment in its U.S. refining operations. Of this amount, U.S. $500 million was designated in the third quarter of 2014. For the three months and year ended December 31, 2014, the Company incurred unrealized losses of $100 million and $260 million, respectively, arising from the translation of the debt, net of tax of $16 million and $39 million, respectively, which was recorded in hedge of net investment within other comprehensive income ("OCI").

During the second quarter of 2014, the balance of Husky's 50 percent contribution receivable, representing BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership, was fully repaid. The contribution receivable was denominated in U.S. dollars, and related gains and losses incurred from changes in the value of the Canadian dollar versus the U.S. dollar were recorded in foreign exchange. The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At December 31, 2014, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At December 31, 2014, the cost of a Canadian dollar in U.S. currency was $0.862.

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)*	**As at December 31, 2014**	As at December 31, 2013
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**(5)**	32
Crude oil[(2)]	**4**	41
Foreign currency contracts – FVTPL		
Foreign currency forwards	**(1)**	—
Other assets – FVTPL	**2**	2
Contingent consideration	**(40)**	(60)
Hedging instruments[(3)]		
Derivatives designated as a cash flow hedge[(4)]	**—**	37
Hedge of net investment[(5)]	**(353)**	(93)
	(393)	(41)

(1) Natural gas contracts include a $12 million decrease as at December 31, 2014 (December 31, 2013 – $27 million increase) to the fair value of held-for-trading inventory, recognized in the Condensed Interim 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 $87 million at December 31, 2014.

(2) Crude oil contracts include a $21 million decrease as at December 31, 2014 (December 31, 2013 – $49 million increase) to the fair value of held-for-trading inventory, recognized in the Condensed Interim Consolidated Balance Sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $199 million at December 31, 2014.

(3) Hedging instruments are presented net of tax.

(4) Forward starting swaps previously designated as a cash flow hedge were discontinued during the first quarter of 2014.

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

8. Critical Accounting Estimates and Key Judgments

Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in Husky's 2013 Annual MD&A, as well as critical areas of judgments have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

During the fourth quarter of 2014, the Company updated its estimates for Asset Retirement Obligations as outlined in Note 11 of the Condensed Interim Consolidated Financial Statements.

During the fourth quarter of 2014, the Company completed an evaluation of its cash generating units and concluded that the carrying amount of certain crude oil and natural gas assets was in excess of the estimated recoverable amount due to lower estimated short and long-term crude oil and natural gas prices. See Note 6 of the Condensed Interim Consolidated Financial Statements.

9. Change in Accounting Policies and Recent Accounting Standards

9.1 Change in Accounting Policies

The International Accounting Standards Board ("IASB") issued amendments to International Accounting Standards 36, "Impairment of Assets" which were adopted by the Company on January 1, 2014. The amendments require disclosure of information about the recoverable amount of impaired assets. The adoption of this amended standard had no impact on the Company's Condensed Interim Consolidated Financial Statements.

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, "Levies" which was adopted by the Company on January 1, 2014. The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had no impact on the Company's Condensed Interim Consolidated Financial Statements.

9.2 Recent Accounting Standards

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 adoption of the standard is not expected to have a material impact on the Company's Consolidated Financial Statements.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to replace IAS 18 which establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The standard is effective for the Company for annual periods beginning on January 1, 2017, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2017. The Company is assessing the impact of this standard and does not expect it to have a material impact on the Company's Consolidated Financial Statements.

10. Outstanding Share Data

Authorized:
- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 9, 2015	
• common shares	983,840,282
• cumulative redeemable preferred shares, series 1	12,000,000
• cumulative redeemable preferred shares, series 3	10,000,000
• stock options	26,335,188
• stock options exercisable	13,614,287

11. Reader Advisories

This MD&A should be read in conjunction with the Condensed Interim Consolidated Financial Statements and related Notes.

Readers are encouraged to refer to Husky's 2013 Annual MD&A, the 2013 Consolidated Financial Statements and the 2013 Annual Information Form filed with Canadian securities regulatory authorities and the 2013 Form 40-F filed with the U.S. Securities and Exchange Commission for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A, the terms "Husky" and "the Company" denote the corporate entity Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended December 31, 2014 are compared to the results for the three months ended December 31, 2013 and the results for the year ended December 31, 2014 are compared to the results for the year ended December 31, 2013. Discussions with respect to Husky's financial position as at December 31, 2014 are compared to its financial position at December 31, 2013. Amounts presented within this MD&A are unaudited.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in this MD&A have been prepared in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting" as issued by the IASB.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended December 31, 2014 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Non-GAAP Measures

Disclosure of Non-GAAP Measurements

Husky uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this MD&A and related disclosures are cash flow from operations, net operating earnings, operating netback, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt and interest coverage on total debt. None of these measurements are used to enhance the Company's reported financial performance or position. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. With the exception of net operating earnings and cash flow from operations, there are no comparable measures in accordance with IFRS. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application. Except as described below, the definitions of these measurements are found in Section 6.1.

Disclosure of Net Operating Earnings

The term "Net Operating Earnings" is a non-GAAP measure comprised of net earnings excluding extraordinary and non-recurring items such as property, plant and equipment impairment charges and inventory write-downs not considered indicative of the Company's on-going financial performance. Net operating earnings is a complementary measure used in assessing Husky's financial performance by providing comparability between periods.

The following table shows the reconciliation of net earnings to net operating earnings and related per share amounts for the three months and years ended December 31, 2014 and 2013:

		Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)		**2014**	2013	**2014**	2013
GAAP	Net earnings (loss)	**(603)**	177	**1,258**	1,829
	Impairment of property, plant and equipment, net of tax	**622**	204	**622**	204
	Inventory write-downs, net of tax	**128**	(6)	**135**	1
Non-GAAP	Net operating earnings[1]	**147**	375	**2,015**	2,034

[1] *Net Operating Earnings were redefined in the fourth quarter of 2014 to include after-tax inventory write-downs. Prior periods have been adjusted to conform with current period presentation.*

Disclosure of Cash Flow from Operations

Husky uses the term "Cash Flow From Operations," which should not be considered an alternative to, or more meaningful than "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Cash flow from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization, impairment, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gain or loss on sale of property, plant, and equipment and other non-cash items.

The following table shows the reconciliation of cash flow – operating activities to cash flow from operations and related per share amounts for the three months and year ended December 31, 2014 and 2013:

		Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)		**2014**	2013	**2014**	2013
GAAP	Cash flow – operating activities	**1,584**	829	**5,585**	4,645
	Settlement of asset retirement obligations	**54**	50	**167**	142
	Income taxes paid	**135**	81	**661**	433
	Interest received	**(1)**	(5)	**(7)**	(19)
	Change in non-cash working capital	**(627)**	188	**(871)**	21
Non-GAAP	Cash flow from operations	**1,145**	1,143	**5,535**	5,222
	Cash flow from operations – basic	**1.16**	1.16	**5.63**	5.31
	Cash flow from operations – diluted	**1.16**	1.16	**5.62**	5.31

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. This measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. The operating netback was determined as realized price less royalties, operating costs and transportation on a per unit basis.

Cautionary Note Required by National Instrument 51-101

The Company uses the term barrels of oil equivalent ("boe"), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

Terms

Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Capital Employed	*Long-term debt including current portion, commercial paper and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gain or loss on sale of property, plant, and equipment and other non-cash items*
Corporate Reinvestment Ratio	*Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and commercial paper divided by capital employed*
Debt to Cash Flow	*Long-term debt, long-term debt due within one year and commercial paper divided by cash flow from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Front-End Engineering Design ("FEED")	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Production	*A company's working interest share of production before deduction of royalties*
Interest Coverage Ratio	*A calculation of a company's ability to meet its interest payment obligation. It is equal to net earnings or cash flow – operating activities before finance expense and income taxes divided by finance expense and capitalized interest*
Net Operating Earnings	*Net earnings before property, plant and equipment impairment charge and inventory write-downs*
Seismic	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Shares, retained earnings and other reserves*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt including long-term debt due within one year, commercial paper and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

bbls	*barrels*	*IFRS*	*International Financial Reporting Standards*
boe	*barrels of oil equivalent*	*mbbls*	*thousand barrels*
bbls/day	*barrels per day*	*mbbls/day*	*thousand barrels per day*
boe/day	*barrels of oil equivalent per day*	*mboe*	*thousand barrels of oil equivalent*
CHOPS	*cold heavy oil production with sand*	*mboe/day*	*thousand barrels of oil equivalent per day*
CGU	*Cash Generating Unit*	*mcf*	*thousand cubic feet*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A.)*	*MD&A*	*Management's Discussion and Analysis*
FEED	*Front-end engineering design*	*mmbbls*	*million barrels*
FIFO	*first in first out*	*mmboe*	*million barrels of oil equivalent*
FPSO	*Floating production, storage and offloading vessel*	*mmbtu*	*million British Thermal Units*
FVTPL	*fair value through profit or loss*	*mmcf*	*million cubic feet*
GAAP	*Generally Accepted Accounting Principles*	*mmcf/day*	*million cubic feet per day*
GJ	*gigajoule*	*NGL*	*natural gas liquids*
IAS	*International Accounting Standard*	*NYMEX*	*New York Mercantile Exchange*
IASB	*International Accounting Standards Board*	*OCI*	*other comprehensive income*
ICFR	*Internal Controls over Financial Reporting*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
IFRIC	*International Financial Reporting Interpretations Committee*	*WTI*	*West Texas Intermediate*

12. Forward-Looking Statements and Information

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

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

- with respect to the business, operations and results of the Company generally: the Company’s general strategic plans and growth strategies;
- with respect to the Company's Atlantic Region: anticipated timing of first production at the Company’s South White Rose Extension project; scheduled timing of first production from the North Amethyst Hibernia-formation well; the scheduled duration and timing of turnarounds for the SeaRose and Terra Nova FPSOs; and the scheduled timing, duration and impact of an inspection of the Terra Nova FPSO;
- with respect to the Company's Oil Sands properties: anticipated timing of first oil at the Company’s Sunrise Energy Project; and anticipated timing of first steam at Plant 1B at the Company’s Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: expected timing of first production and anticipated volumes of production at the Company’s Rush Lake, Edam East, Edam West and Vawn heavy oil thermal developments; the scheduled timing and duration of a turnaround at the Tucker heavy oil thermal project; and the scheduled timing and anticipated impact of partial shut-downs at several heavy oil thermal projects;
- with respect to the Company's Western Canadian oil and gas resource plays: scheduled timing and anticipated impact of turnarounds at the Ansell liquids-rich natural gas resource play and Ram River plant; and scheduled timing and anticipated impact of third-party shutdowns in Western Canada;
- with respect to the Company’s Infrastructure and Marketing operating segment: scheduled timing of completion of, and anticipated outcome of, the Hardisty terminal expansion project; and

- with respect to the Company's Downstream operating segment: the anticipated benefits from the Lima, Ohio Refinery feedstock flexibility project and the anticipated processing capacity of Western Canadian heavy oil once reconfiguration is complete; the anticipated benefits of the Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; and the scheduled timing of a turnaround at the BP-Husky Toledo Refinery.

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

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

The Company's Annual Information Form for the year ended December 31, 2013 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

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