MANAGEMENT'S DISCUSSION AND ANALYSIS

October 22, 2014

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Sept. 30**	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31
($ millions, except where indicated)	**2014**	2014	2014	2013	2013	2013	2013	2012
Production *(mboe/day)*	**341.1**	333.6	325.9	308.3	308.5	309.9	321.3	319.3
Gross revenues[(1)]	**6,690**	6,614	5,943	6,132	6,036	6,206	5,807	5,889
Net earnings	**571**	628	662	177	512	605	535	474
Per share – Basic	**0.58**	0.63	0.67	0.18	0.52	0.61	0.54	0.48
Per share – Diluted	**0.52**	0.63	0.66	0.18	0.52	0.59	0.54	0.48
Cash flow from operations[(2)]	**1,341**	1,504	1,536	1,143	1,347	1,449	1,283	1,414
Per share – Basic	**1.36**	1.53	1.56	1.16	1.37	1.47	1.31	1.44
Per share – Diluted	**1.36**	1.52	1.56	1.16	1.37	1.47	1.30	1.44

(1) *Gross revenues have been recast to reflect a change in the classification of certain trading transactions.*
(2) *Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.*

Performance

- Production increased by 32.6 mboe/day or 11 percent to 341.1 mboe/day in the third quarter of 2014 compared to the third quarter of 2013 as a result of:
  - Production from the Liwan Gas Project which continued to increase in the quarter;
  - Strong production performance from heavy oil thermal developments, including the Sandall development which began producing crude oil in the first quarter of 2014;
  - Increased production from the Ansell multi-zone liquids-rich natural gas resource play; and
  - Production from the multilateral well at North Amethyst brought on stream in the fourth quarter of 2013;
  - Partially offset by lower production at the Wenchang field due to the planned floating production, storage and offloading ("FPSO") vessel offstation and in the Atlantic Region due to the completion of planned maintenance turnarounds on the SeaRose and Terra Nova FPSOs and the planned installation of production equipment for the South White Rose development.
- Net earnings increased by $59 million or 12 percent to $571 million in the third quarter of 2014 compared to $512 million in the third quarter of 2013 due to:
  - Increased crude oil and natural gas production partially offset by lower realized crude oil prices;
  - Higher realized natural gas prices in North America combined with new production from the Liwan Gas Project;
  - Higher Upgrading throughputs compared to the same period in 2013 when a major turnaround was ongoing;
  - Higher Refining and Asphalt margins in Canadian Refined Products; and
  - Recovery of stock-based compensation expense due to the decrease in the Company's share price.
- Cash flow from operations of $1,341 million in the third quarter of 2014 was comparable to the third quarter of 2013.

Key Projects

- Phase 1 of the Sunrise Energy Project remains on track to start steaming around the end of 2014. Hydro testing is now complete for Plant 1A, the first 30,000 bbls/day central processing plant, with reinstatements nearing completion. Major systems continue to be handed over for commissioning.
- At the Liwan Gas Project, production from the Liwan 3-1 gas field continued to increase in the third quarter of 2014. Progress was made on the laying of a second 22-inch pipeline from the 3-1 field to the shallow water platform. The Liuhua 34-2 field is due for commissioning subject to final approvals.
- In Indonesia, progress continued on the shallow water gas developments in the Madura Strait Block and a letter of intent to award the contract for the lease of an FPSO vessel has been issued with design and planning work expected to commence in the fourth quarter of 2014.
- In the Atlantic Region, drilling of the North Amethyst Hibernia formation well is continuing and production is planned around the end of the year.
- At the Sandall heavy oil thermal development, production response continues to be strong with oil rates averaging 5,300 bbls/day in the third quarter of 2014.
- Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the second half 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.
- Resource play development progressed in Western Canada with 15 oil wells (gross) and seven liquids-rich natural gas wells (gross) drilled and 15 oil wells (gross) and 12 liquids-rich natural gas wells (gross) completed.
- Front-end engineering design ("FEED") on the Lima feedstock flexibility project is now complete, detailed engineering is on going, and long lead equipment has been ordered.

Financial

- Dividends on common shares of $295 million for the second quarter of 2014 were declared during the third quarter of 2014, of which $291 million and $4 million were paid in cash and common shares, respectively, on October 1, 2014.

2. Business Environment

Average Benchmarks		Three months ended Sept. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Sept. 30, 2013
WTI crude oil[1]	*(U.S. $/bbl)*	**97.17**	102.99	98.68	97.46	105.83
Brent crude oil[2]	*(U.S. $/bbl)*	**101.85**	109.61	108.22	108.34	108.21
Canadian light crude 0.3 percent sulphur	*($/bbl)*	**88.53**	96.29	89.60	88.29	104.91
Western Canadian Select[3]	*(U.S. $/bbl)*	**76.99**	82.95	75.55	65.26	88.35
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**77.96**	80.98	72.42	57.70	86.26
NYMEX natural gas[4]	*(U.S. $/mmbtu)*	**4.06**	4.67	4.94	3.61	3.58
NIT natural gas	*($/GJ)*	**4.00**	4.44	4.51	2.99	2.67
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**20.23**	20.17	23.09	32.42	17.50
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**18.86**	19.27	20.32	18.90	17.32
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**17.41**	19.40	18.35	11.91	15.86
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.918**	0.917	0.906	0.953	0.963
Canadian $ Equivalents[5]						
WTI crude oil	*($/bbl)*	**105.85**	112.31	108.92	102.26	109.90
Brent crude oil	*($/bbl)*	**110.95**	119.53	119.45	113.68	112.37
WTI/Lloyd crude blend differential	*($/bbl)*	**22.04**	22.00	25.49	34.02	18.17
NYMEX natural gas	*($/mmbtu)*	**4.42**	5.09	5.45	3.79	3.72

(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 averaged U.S. $97.17/bbl in the third quarter of 2014 compared to U.S. $105.83/bbl in the same period of 2013. The price of WTI averaged U.S. $99.61/bbl in the first nine months of 2014 compared to U.S. $98.14/bbl in the same period of 2013. The price of Brent averaged U.S. $101.85/bbl in the third quarter of 2014 compared to U.S. $108.21/bbl in the same period of 2013. The price of Brent averaged U.S. $106.56/bbl in the first nine months of 2014 compared to U.S. $107.76/bbl in the same period of 2013.

Crude oil prices in the third quarter and in the first nine months of 2014 benefited from the weakening of the Canadian dollar against the U.S. dollar compared to the same periods in 2013. In the third quarter of 2014, the price of WTI in U.S. dollars decreased 8 percent compared to a decrease of 4 percent in Canadian dollars compared to the same period in 2013. In the first nine months of 2014, the price of WTI in U.S. dollars increased 1 percent compared to an increase of 8 percent in Canadian dollars compared to the same period in 2013. In the third quarter of 2014, the price of Brent in U.S. dollars decreased 6 percent compared to a decrease of 1 percent in Canadian dollars compared to the same period in 2013. In the first nine months of 2014, the price of Brent in U.S. dollars decreased 1 percent compared to an increase of 8 percent in Canadian dollars compared to the same period in 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. $20.23/bbl or 21 percent of WTI in the third quarter of 2014 compared to U.S. $17.50/bbl or 17 percent of WTI in the third quarter of 2013. The light/heavy crude oil differential averaged U.S. $21.16/bbl or 21 percent of WTI in the first nine months of 2014 compared to $22.95/bbl or 23 percent of WTI in the same period in 2013.

During the third quarter of 2014, the NYMEX near-month contract price of natural gas averaged U.S. $4.06/mmbtu compared to U.S. $3.58/mmbtu in the same period of 2013, an increase of 13 percent. During the first nine months of 2014, the NYMEX near-month contract price of natural gas averaged U.S. $4.56/mmbtu compared to U.S. $3.67/mmbtu during the same period of 2013, an increase of 24 percent. During the third quarter of 2014, the NOVA Inventory Transfer ("NIT") near-month contract price of natural gas averaged $4.00/GJ compared to $2.67/GJ in the same period in 2013, an increase of 50 percent. During the first nine months of 2014, the NIT near-month contract price of natural gas averaged $4.32/GJ compared to $3.00/GJ in the same period in 2013, an increase of 44 percent.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. 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.

In the third quarter of 2014, the Canadian dollar averaged U.S. $0.918, weakening by 5 percent compared to U.S. $0.963 during the same period of 2013. In the first nine months of 2014, the Canadian dollar averaged U.S. $0.914, weakening by 6 percent compared to U.S. $0.977 during the same period of 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 third quarter of 2014, the Chicago 3:2:1 crack spread averaged U.S. $17.41/bbl compared to U.S. $15.86/bbl in the same period of 2013. In the first nine months of 2014, the Chicago 3:2:1 crack spread averaged U.S. $18.38/bbl compared to U.S. $24.45/bbl in the same period of 2013. During the third quarter of 2014, the New York Harbour 3:2:1 crack spread averaged U.S. $18.86/bbl compared to U.S. $17.32/bbl in the same period of 2013. In the first nine months of 2014, the New York Harbour 3:2:1 crack spread averaged U.S. $19.47/bbl compared to U.S. $23.32/bbl in the same period of 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 by the time lag between the purchase and delivery of crude oil. Husky's realized refining margins are accounted for on a first in first out ("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 third quarter of 2014. The table below reflects what the effect would have been on the financial results for the third quarter of 2014 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the third 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 Third 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]	**97.17**	*U.S. $1.00/bbl*	**82**	**0.08**	**60**	**0.06**
NYMEX benchmark natural gas price[5]	**4.06**	*U.S. $0.20/mmbtu*	**37**	**0.04**	**27**	**0.03**
WTI/Lloyd crude blend differential[6]	**20.23**	*U.S. $1.00/bbl*	**(29)**	**(0.03)**	**(22)**	**(0.02)**
Canadian light oil margins	**0.05**	*Cdn $0.005/litre*	**16**	**0.02**	**12**	**0.01**
Asphalt margins	**19.33**	*Cdn $1.00/bbl*	**13**	**0.01**	**10**	**0.01**
New York Harbour 3:2:1 crack spread	**18.86**	*U.S. $1.00/bbl*	**51**	**0.05**	**30**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.918**	*U.S. $0.01*	**(82)**	**(0.08)**	**(61)**	**(0.06)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.6 million common shares outstanding as of September 30, 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 in 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 and 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 builds on the momentum achieved over the past three years with respect to repositioning the Heavy Oil and Western Canada foundation by accelerating 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)

Oil Resource Plays

In the third quarter of 2014, 15 horizontal wells (gross) were drilled and 15 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 Sept. 30, 2014		Nine months ended Sept. 30, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	3	2	7	7
Lower Shaunavon	S.W. Saskatchewan	—	—	—	2
Viking[2]	Alberta and S.W. Saskatchewan	9	13	22	21
N.Cardium	Wapiti, Alberta	2	—	6	8
Muskwa	Rainbow Region	1	—	1	2
Total Gross		15	15	36	40
Total Net		14	12	33	37

[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.*

Construction of the all-season road at the Slater River Canol shale play in the Northwest Territories was completed in the third quarter of 2014.

Liquids-Rich Natural Gas Resource Plays

The liquids-rich natural gas formations in west central Alberta continue to be an area of focus for the Company.

In the third quarter of 2014, seven wells (gross) were drilled and 12 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 Sept. 30, 2014		Nine months ended Sept. 30, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	3	9	22	17
Duvernay	Kaybob, Alberta	—	—	—	2
Wilrich	Kakwa, Alberta	—	—	6	3
Strachan Cardium	Rocky Mountain House, Alberta	3	3	7	9
Bivouac Muskwa	Bivouac, B.C.	1	—	1	—
Total Gross		7	12	36	31
Total Net		5	8	27	25

(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, three horizontal wells (gross) were drilled and nine horizontal wells (gross) were completed in the third quarter of 2014. Average production from the play was approximately 17,500 boe/day in the third quarter of 2014.

In the Duvernay liquids-rich natural gas resource play at Kaybob, production results from the four-well and two-well pads continue to be in line with expectations.

In the Strachan area located near Rocky Mountain House, Alberta, three horizontal wells (gross) were drilled and three horizontal wells were completed. Further development drilling is scheduled in 2014.

Conventional Oil and Gas

Approximately 15 wells (gross) were drilled and 36 wells (gross) were completed in the third 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 5,300 bbls/day in the third quarter of 2014.

Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the second half 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 developments expected in 2016.

Total production from the Company's existing heavy oil thermal developments averaged approximately 45,400 bbls/day in the third quarter of 2014.

Husky continues to evaluate the results of the McMullen winter drilling and seismic program, which was completed in the first half of 2014.

Thirty-nine horizontal heavy oil wells (gross) were drilled during the third quarter of 2014 and 50 Cold Heavy Oil Production with Sand ("CHOPS") wells (gross) were drilled during the third quarter of 2014.

Asia Pacific Region

China

Block 29/26

Production from the Liwan 3-1 gas field continued to increase in the third quarter of 2014. Progress was made on the laying of a second 22-inch pipeline from the 3-1 field to the shallow water platform. Pending vessel availability, plans are being finalized for the completion of the pipeline.

The Liuhua 34-2 field is due for commissioning subject to final approvals.

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 are in progress.

Indonesia

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 23 percent complete. A letter of intent to award the contract for the lease of an FPSO vessel has been issued and design and planning work will commence in the fourth quarter of 2014.

Tender plans for the MDA and MBH development projects have been approved by SKK Migas, the Indonesia oil and gas regulator, and the tendering process has commenced. The Gas Sales Agreement for the first tranche of gas sales is being negotiated following the signing of a corresponding Heads of Agreement in the first quarter of 2014.

The development plan for the MDK field to tie into the MDA/MBH combined development was approved by SKK Migas in July.

Planning for exploration work, including a 3-D seismic survey on the Anugerah contract area, is in progress.

Oil Sands

Sunrise Energy Project

Phase 1 of the Sunrise Energy Project remains on track to start steaming around the end of 2014. Hydro testing is now complete for Plant 1A, the first 30,000 bbls/day central processing plant, with reinstatements nearing completion. Major systems continue to be handed over for commissioning.

Development work on the second 30,000 bbls/day central processing facility, Plant 1B, continued in the third quarter of 2014 and remains on track to start steaming approximately six months after Plant 1A.

Atlantic Region

White Rose Field and Satellite Extensions

Drilling of the North Amethyst Hibernia formation well is underway and production is planned around the end of the year. The well targets a secondary deeper zone below the main North Amethyst producing field.

Production equipment was installed at the South White Rose Extension. Development drilling is scheduled to begin later this year with first oil planned in the second quarter of 2015.

Early site preparation is advancing, including construction of the graving dock, at the West White Rose Extension project. Public consultations on the project were completed as planned in the third quarter of 2014.

Atlantic Exploration

Drilling of an exploration well on the Aster prospect in the Flemish Pass Basin is scheduled to begin in the fourth quarter of 2014.

During the third quarter of 2014, the 3-D seismic program over the Bay du Nord discovery offshore Newfoundland was completed. The semi-submersible drilling rig West Hercules arrived in mid-October to begin an 18-month exploration and appraisal program.

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 is now complete and the installation of structural steel and piping is ongoing with the project expected to be complete in early 2015. The project is expected to significantly expand the blending capacity of Western Canada Select.

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

4.2 Downstream

Husky Lima, Ohio Refinery

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. Enhanced feedstock and product slate flexibility would allow the refinery to take advantage of heavy/light price and end product margin differentials while supporting anticipated production growth.

BP-Husky Toledo, Ohio Refinery

Work continued on the Hydrotreater Recycle Gas Compressor Project during the third quarter of 2014 and is scheduled to be completed towards the end of 2014. The project is intended to improve operational integrity and plant performance.

5. Results of Operations

5.1 Upstream

Total Third Quarter Upstream Earnings 2014 - $460 million, 2013 - $460 million.

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 stronger Exploration and Production earnings compared to the same period in 2013 offset by decreased earnings in Infrastructure and Marketing. The shift in earnings between the two operations reflects the Company's integration strategy and the ability to capture value as it moves along the value chain.

Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	Three months ended Sept. 30, 2014	2013	Nine months ended Sept. 30, 2014	2013
Gross revenues	**2,210**	2,111	**6,744**	5,599
Royalties	**(260)**	(237)	**(852)**	(649)
Net revenues	**1,950**	1,874	**5,892**	4,950
Purchases, operating, transportation and administrative expenses	**663**	605	**1,939**	1,772
Depletion, depreciation and amortization	**671**	594	**1,881**	1,724
Exploration and evaluation expenses	**42**	56	**101**	218
Other expenses (income)	**(8)**	39	**135**	112
Income taxes	**146**	150	**470**	290
Net earnings	**436**	430	**1,366**	834

Third Quarter

Exploration and Production net earnings in the third quarter of 2014 increased by $6 million compared to the third quarter of 2013 primarily due to increased crude oil and natural gas production and higher natural gas prices in Canada and Asia offset by decreased crude oil prices, higher royalties and increased depletion, depreciation and amortization expenses.

Production increased by 32.6 mboe/day in the third quarter of 2014 compared to the same period in 2013. The increase in production was primarily due to higher natural gas and NGL production from the Liwan Gas Project, increased heavy crude oil production from the Sandall heavy oil thermal development and new production from the North Amethyst multi-lateral well partially offset by lower production at the Wenchang field due to the planned FPSO vessel offstation and in the Atlantic Region due to the completion of planned maintenance turnarounds on the SeaRose and Terra Nova FPSOs and the planned installation of production equipment for the South White Rose development.

The average realized price for crude oil, NGL and bitumen in the third quarter of 2014 was $83.73/bbl compared to $93.23/bbl during the same period in 2013, an 10 percent decrease, due to lower Brent, WTI and heavy crude oil and bitumen market prices partially offset by a weaker Canadian dollar. Realized natural gas prices averaged $6.11/mcf in the third quarter of 2014 compared to $2.66/mcf in the same period in 2013, an increase of 130 percent, primarily due to higher realized prices on production from the Liwan Gas Project and higher benchmark prices in Canada.

Nine Months

Exploration and Production net earnings in the first nine months of 2014 were $532 million higher compared to the same period in 2013 primarily due to increased crude oil and natural gas production and higher realized crude oil and natural gas prices. During the first nine months of 2014, the average realized price for crude oil, NGL and bitumen was $87.11/bbl compared to $79.80/bbl in the same period in 2013, an increase of 9 percent. During the first nine months of 2014, the average realized natural gas price was $5.84/mcf compared to $3.15/mcf in the same period in 2013, an increase of 85 percent due to favourable pricing at the Liwan Gas Project.

Average Sales Prices Realized	Three months ended Sept. 30, 2014	2013	Nine months ended Sept. 30, 2014	2013
Crude oil and NGL *($/bbl)*				
Light crude oil & NGL	**96.47**	107.83	**105.97**	102.48
Medium crude oil	**83.35**	93.67	**85.52**	76.50
Heavy crude oil	**77.29**	84.45	**76.36**	65.83
Bitumen	**75.50**	83.17	**74.84**	64.17
Total crude oil and NGL average	**83.73**	93.23	**87.11**	79.80
Natural gas average *($/mcf)*	**6.11**	2.66	**5.84**	3.15
Total average *($/boe)*	**68.35**	72.13	**71.71**	63.09

The price realized for Western Canada crude oil in the third quarter of 2014 reflected lower WTI and heavy crude oil and bitumen prices partially offset by a weaker Canadian dollar. 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 Sept. 30, 2014	2013	Nine months ended Sept. 30, 2014	2013
Crude Oil and NGL *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**30.3**	29.2	**29.8**	29.5
Medium crude oil	**20.2**	23.2	**22.1**	23.1
Heavy crude oil	**76.1**	75.3	**76.5**	74.0
Bitumen[(1)]	**56.2**	48.0	**54.3**	48.0
	182.8	175.7	**182.7**	174.6
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**33.3**	34.5	**39.7**	39.3
Terra Nova – light crude oil	**4.0**	7.2	**5.3**	5.9
	37.3	41.7	**45.0**	45.2
Asia Pacific Region				
Light crude oil & NGL[(2)]	**9.3**	6.8	**6.9**	7.4
	229.4	224.2	**234.6**	227.2
Natural gas *(mmcf/day)*				
Western Canada	**509.3**	505.5	**502.0**	515.8
Asia Pacific Region[(2)]	**161.0**	—	**91.9**	—
	670.3	505.5	**593.9**	515.8
Total *(mboe/day)*	**341.1**	308.5	**333.6**	313.2

(1) *Bitumen production includes heavy oil thermal average daily gross production of 45.4 mbbls/day and 43.3 mbbls/day for the three months and nine months ended September 30, 2014, respectively.*

(2) *Reported production volumes include Husky's net working interest production from the Liwan Gas Project (49%) 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

Third Quarter

Crude oil and NGL production in the third quarter of 2014 increased by 5.2 mbbls/day or 2 percent compared to the same period in 2013. The increase was primarily due to new NGL production from the Liwan Gas Project, increased liquids rates at the Ansell multi-zone liquids-rich natural gas resource play, higher heavy oil thermal production at the Sandall heavy oil thermal development and new production from the North Amethyst multilateral well. The increase in crude oil and NGL production was partially offset by lower production at the Wenchang field due to the planned FPSO vessel offstation and in the Atlantic Region due to the completion of planned maintenance turnarounds on the SeaRose and Terra Nova FPSOs and the planned installation of production equipment for the South White Rose development.

Nine Months

In the first nine months of 2014, crude oil and NGL production increased by 7.4 mbbls/day or 3 percent compared to the same period in 2013 primarily due to the same factors which impacted the third quarter.

Natural Gas Production

Third Quarter

Natural gas production in the third quarter of 2014 increased by 164.8 mmcf/day or 33 percent compared to the same period in 2013 primarily due to production from the Liwan Gas Project and increased production at Ansell.

Nine Months

In the first nine months of 2014, natural gas production increased by 78.1 mmcf/day or 15 percent compared to the same period in 2013 primarily due to the same factors impacting the third quarter offset by natural reservoir declines in Western Canada mature properties as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

2014 Production Guidance

The following table shows actual daily production for the nine months ended September 30, 2014 and the year ended December 31, 2013, as well as the previously issued production guidance for 2014.

		Actual Production	
	2014 Guidance	Nine months ended September 30, 2014	Year ended December 31, 2013
Crude oil, NGL and Asia Pacific Gas *(mbbls/day)*			
Light / Medium crude oil & NGL	110 – 115	101	104
Heavy crude oil	125 – 130	131	122
Natural Gas & NGL Asia Pacific Region *(mboe/day)*	25 – 30	18	—
	260 – 275	250	226
Natural Gas Canada *(mmcf/day)*	420 – 480	502	513
Total *(mboe/day)*	330 – 355	334	312

Royalties

Third Quarter

Royalty rates as a percentage of gross revenues averaged 12 percent in both the third quarter of 2014 and 2013. Royalty rates in Western Canada averaged 12 percent in the third quarter of 2014 compared to 11 percent in the same period in 2013 reflecting higher natural gas prices and corresponding royalty rates. Royalty rates for the Atlantic Region averaged 17 percent in the third quarter of 2014 compared to 12 percent in the same period 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 7 percent in the third 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 combined with the impact of lower production at the higher royalty rate Wenchang field resulting from the planned FPSO vessel offstation which commenced in early April.

Nine Months

Royalty rates averaged 13 percent of gross revenues in the first nine months of 2014 compared to 12 percent in the same period in 2013 due to the same factors which impacted the third quarter of 2014. Royalty rates in Western Canada averaged 12 percent in the first nine months of 2014 compared to 11 percent in the same period in 2013. Royalty rates for the Atlantic Region averaged 19 percent in the first nine months of 2014 compared to 13 percent in the same period in 2013. Royalty rates in the Asia Pacific Region averaged 9 percent in the first nine months of 2014 compared to 25 percent in the same period in 2013.

Operating Costs

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	2014	2013	2014	2013
Western Canada	456	456	1,382	1,317
Atlantic Region	62	51	164	144
Asia Pacific	30	8	48	21
Total	548	515	1,594	1,482
Unit operating costs *($/boe)*	16.61	17.20	16.48	16.27

Third Quarter

Operating costs in Western Canada averaged $17.44/boe in the third quarter of 2014 compared to $17.98/boe in the same period in 2013. The decrease was due to lower power prices in the third quarter of 2014 and one-time maintenance costs in the third quarter of 2013.

Operating costs in the Atlantic Region averaged $17.86/boe in the third quarter of 2014 compared to $13.31/boe in the same period in 2013 due to turnaround activities.

Operating costs in the Asia Pacific Region averaged $9.38/boe in the third quarter of 2014 compared to $12.72/boe in the same period in 2013. The decrease was primarily attributable to lower operating costs on a per barrel basis associated with the Liwan Gas Project which came on stream at the end of the first quarter of 2014.

Nine Months

Total Exploration and Production operating costs in the first nine months of 2014 were $1,594 million compared to $1,482 million in the same period in 2013. Operating costs in Western Canada averaged $17.71/boe in the first nine months of 2014 compared to $17.22/boe in the same period in 2013 primarily due to increased natural gas prices and higher energy consumption related to new heavy oil thermal developments. Operating costs in the Atlantic Region averaged $13.33/boe in the first nine months of 2014 compared to $11.64/boe in the same period in 2013 primarily due to higher ice management costs and the completion of maintenance turnarounds on the SeaRose and Terra Nova FPSOs. Operating costs in the Asia Pacific Region averaged $7.97/boe in the first nine months of 2014 compared to $10.64/boe in the same period in 2013 due to the same factors which impacted the third quarter.

Exploration and Evaluation Expenses

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2014**	2013	**2014**	2013
Seismic, geological and geophysical	**37**	25	**79**	102
Expensed drilling	**1**	28	**14**	107
Expensed land	**4**	3	**8**	9
Exploration and evaluation expenses	**42**	56	**101**	218

Third Quarter

Exploration and evaluation expenses in the third quarter of 2014 were $42 million compared to $56 million in the third quarter of 2013. The increase in seismic, geological and geophysical expenses was due to the acquisition of seismic data in the Atlantic Region in the third quarter of 2014. Expensed drilling in 2013 included costs associated with the Federation well in the Atlantic Region which did not encounter commercial quantities of hydrocarbons.

Nine Months

Exploration and evaluation expenses in the first nine months of 2014 were $101 million compared to $218 million in the same period of 2013. Expensed drilling in the first nine months of 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 the first nine months of 2013 included a one time work commitment penalty in the second quarter of 2013 in the Atlantic Region.

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

Third Quarter

In the third quarter of 2014, total DD&A averaged $21.36/boe, which was comparable to $20.93/boe in the third quarter of 2013.

Nine Months

For the first nine months of 2014, total DD&A averaged $20.64/boe, which was comparable to $20.16/boe during the same period in 2013.

Exploration and Production Capital Expenditures

In the first nine months of 2014, Upstream Exploration and Production capital expenditures were $3,053 million. Capital expenditures were $1,707 million (56%) in Western Canada including Heavy Oil, $488 million (16%) in Oil Sands, $479 million (16%) in the Atlantic Region and $379 million (12%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1]	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2014**	2013	**2014**	2013
Exploration				
Western Canada[2]	**42**	99	**172**	273
Oil Sands[2]	**—**	—	**5**	—
Atlantic Region	**12**	102	**34**	146
Asia Pacific Region	**2**	1	**11**	7
	56	202	**222**	426
Development				
Western Canada	**456**	505	**1,515**	1,285
Oil Sands	**203**	146	**483**	441
Atlantic Region	**201**	148	**445**	403
Asia Pacific Region	**139**	133	**368**	418
	999	932	**2,811**	2,547
Acquisitions				
Western Canada	**15**	1	**20**	11
	1,070	1,135	**3,053**	2,984

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *During the second quarter of 2014, the Company redefined its McMullen property as a Heavy Oil thermal development resulting in the reclassification of capital expenditures from Oil Sands to Western Canada including Heavy Oil.*

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 Sept. 30,				Nine months ended Sept. 30,			
Wells Drilled[1]	**2014**		2013		**2014**		2013	
(wells)	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**4**	**1**	11	8	**52**	**45**	28	17
Gas	**1**	**1**	1	—	**6**	**4**	12	9
Dry	**—**	**—**	—	—	**—**	**—**	—	—
	5	**2**	12	8	**58**	**49**	40	26
Development								
Oil	**153**	**132**	269	249	**370**	**326**	551	508
Gas	**27**	**25**	15	12	**69**	**60**	53	29
Dry	**1**	**1**	—	—	**1**	**1**	1	—
	181	**158**	284	261	**440**	**387**	605	537
Total	**186**	**160**	296	269	**498**	**436**	645	563

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

The Company drilled 436 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first nine months of 2014 resulting in 371 net oil wells and 64 net natural gas wells compared to 563 net wells resulting in 525 net oil wells and 38 net natural gas wells in the same period of 2013.

During the first nine months of 2014, Husky invested $1,707 million in exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $1,569 million in the same period in 2013. Property acquisitions totalling $20 million were completed in the first nine months of 2014 compared to $11 million in the same period in 2013. Oil related exploration and development in the first nine months of 2014 was $291 million compared to $404 million in the same period in 2013. Investment in natural gas related exploration and development, primarily liquids-rich, was $408 million in the first nine months of 2014 compared to $381 million in the same period in 2013.

In addition, $63 million was spent on production optimization and cost reduction initiatives in the first nine months of 2014 compared to $165 million in the same period in 2013. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $506 million in the first nine months of 2014 compared to $234 million in the same period in 2013.

Capital expenditures on heavy oil thermal developments, CHOPS drilling and horizontal drilling were $419 million in the first nine months of 2014 compared to $374 million in the same period in 2013.

Oil Sands

During the first nine months of 2014, $488 million was invested in Oil Sands projects, compared to $441 million in the same period in 2013, primarily on Phase 1 of the Sunrise Energy Project.

Atlantic Region

During the first nine months of 2014, $479 million was invested in Atlantic Region projects, compared to $549 million in the same period in 2013, primarily on the continued development of the White Rose Extension projects, including the North Amethyst, West White Rose and South White Rose Extension satellite fields.

Asia Pacific Region

During the first nine months of 2014, $379 million was invested in Asia Pacific Region projects, compared to $425 million in the same period of 2013, primarily on the continued development of the Liwan Gas Project.

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 Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Infrastructure gross margin	**36**	37	**112**	111
Marketing and other gross margin	**11**	17	**48**	236
Gross margin	**47**	54	**160**	347
Operating and administrative expenses	**10**	7	**27**	28
Depreciation and amortization	**6**	6	**19**	18
Other income	**(1)**	—	**(1)**	(1)
Income taxes	**8**	11	**29**	77
Net earnings	**24**	30	**86**	225
Commodity trading volumes managed *(mboe/day)*	**242.3**	165.8	**254.5**	171.2

Third Quarter

Infrastructure and Marketing net earnings in the third quarter of 2014 decreased by $6 million compared to the same period in 2013 as a result of narrowing product differentials between Canada and the United States.

Nine Months

Infrastructure and Marketing net earnings in the first nine months of 2014 decreased by $139 million compared to the same period in 2013 primarily due to the same factors which impacted the third quarter of 2014 in addition to increased volatility of market prices for natural gas in the first quarter of 2014 which resulted in higher losses on forward natural gas contracts.

Infrastructure and Marketing Capital Expenditures

In the first nine months of 2014, Infrastructure and Marketing expenditures totalled $113 million compared to $55 million in the same period of 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 Third Quarter Downstream Earnings 2014 - $117 million, 2013 - $89 million

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 increased Upgrading margins primarily due to higher throughput and stronger refining and asphalt margins in Canadian Refined Products, partially offset by a decrease in U.S. Refining and Marketing realized margins due to FIFO losses.

Upgrader

Upgrader Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Gross revenues	**604**	437	**1,737**	1,539
Gross margin	**113**	96	**441**	523
Operating and administrative expenses	**45**	40	**139**	121
Depreciation and amortization	**27**	24	**79**	71
Other expenses	**—**	—	**9**	2
Income taxes	**10**	8	**55**	85
Net earnings	**31**	24	**159**	244
Upgrader throughput *(mbbls/day)*(1)	**73.9**	51.3	**71.5**	66.3
Synthetic crude oil sales *(mbbls/day)*	**56.1**	37.5	**52.7**	50.0
Upgrading differential *($/bbl)*	**19.98**	23.59	**23.99**	29.85
Unit margin *($/bbl)*	**21.89**	27.83	**30.65**	38.32
Unit operating cost *($/bbl)*(2)	**6.18**	8.48	**6.76**	6.69

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

Third 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.

Upgrading net earnings increased by $7 million in the third quarter of 2014 compared to the same period in 2013 primarily due to higher throughput and sales volumes compared to the same period in 2013 when a major planned turnaround was ongoing, partially offset by lower realized upgrading differentials.

During the third quarter of 2014, the upgrading differential averaged $19.98/bbl, a decrease of $3.61/bbl or 15 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 third quarter of 2014 was $106.80/bbl compared to $113.86/bbl in the same period in 2013.

Nine Months

Upgrading net earnings for the first nine months of 2014 decreased by $85 million compared to the same period in 2013. The decrease in net earnings was primarily due to lower realized upgrading differentials resulting from an increase in heavy oil feedstock prices, partially offset by higher throughput and sales volumes in 2014 due to the planned turnaround activity in the third quarter of 2013. The average price for Husky Synthetic Blend in the first nine months of 2014 was $108.62/bbl compared to $103.46/bbl in the same period in 2013.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Gross revenues	**1,145**	993	**3,075**	2,449
Gross margin				
Fuel	**45**	32	**110**	106
Refining	**57**	28	**202**	121
Asphalt	**64**	42	**183**	175
Ancillary	**15**	16	**43**	42
	181	118	**538**	444
Operating and administrative expenses	**76**	66	**226**	188
Depreciation and amortization	**26**	23	**75**	67
Other expenses (recovery)	**2**	(2)	**4**	(2)
Income taxes	**20**	8	**60**	49
Net earnings	**57**	23	**173**	142
Number of fuel outlets[(1)]	**502**	507	**502**	511
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*[(2)]	**8.5**	8.3	**8.0**	8.2
Fuel sales per retail outlet *(thousands of litres/day)*[(2)]	**13.7**	13.4	**13.2**	13.8
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**11.7**	11.8	**11.7**	9.7
Lloydminster Refinery *(mbbls/day)*	**28.3**	28.7	**28.8**	25.4
Ethanol production *(thousands of litres/day)*	**768.1**	713.0	**779.5**	731.0

(1) *Average number of fuel outlets for period indicated.*
(2) *Prior periods have been adjusted to reflect a change in classification of certain retail sales volumes.*

Third Quarter

Higher fuel gross margins in the third quarter of 2014 compared to the same period in 2013 were primarily due to higher diesel margins and higher fuel sales volumes.

Higher refining gross margins in the third quarter of 2014 compared to the same period in 2013 were primarily due to lower feedstock costs at the Lloydminster and Minnedosa Ethanol plants and higher product prices at the Prince George Refinery.

Higher asphalt gross margins in the third quarter of 2014 compared to the same period in 2013 were primarily due to lower feedstock costs, partially offset by lower demand for asphalt in Western Canada.

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

Nine Months

During the first nine months of 2014, Canadian Refined Products earnings increased by $31 million compared to the same period in 2013 primarily due to higher refining margins resulting from higher refinery throughput and lower feedstock costs at the ethanol plants, partially offset by higher operating costs, lower fuel sales and higher feedstock costs at the Prince George and Lloydminster Refineries.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Gross revenues	**2,811**	2,405	**8,159**	8,038
Gross refining margin	**240**	231	**873**	1,035
Operating and administrative expenses	**116**	109	**358**	322
Depreciation and amortization	**77**	58	**200**	173
Other expenses	**1**	—	**2**	2
Income taxes	**17**	22	**116**	188
Net earnings	**29**	42	**197**	350
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**156.0**	148.8	**134.3**	148.6
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**64.2**	59.1	**63.0**	64.4
Refining margin *(U.S. $/bbl crude throughput)*	**11.42**	11.86	**15.26**	17.57
Refinery inventory *(mmbbls)*[1]	**11.3**	11.3	**11.3**	11.3

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

Third Quarter

U.S. Refining and Marketing net earnings decreased in the third quarter of 2014 compared to the same period in 2013 primarily due to FIFO losses offsetting higher market crack spreads and increased depreciation and amortization expense, partially offset by increased throughput at both the Lima and BP-Husky Toledo refineries. Throughput at the BP-Husky Toledo Refinery was lower in the third quarter of 2013 compared to the same period this year due to unplanned operational downtime. At the Lima Refinery, throughput was higher in the third quarter of 2014 compared to the third quarter of 2013 as a result of higher levels of crude supply to the refinery.

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 $28 million in the third quarter of 2014 compared to an increase in net earnings of approximately $47 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.

Nine Months

Net earnings in the first nine months of 2014 decreased by $153 million compared to the same period in 2013 primarily due to lower Chicago 3:2:1 market crack spreads in the first half of 2014 and lower throughput resulting from planned maintenance at the Lima Refinery in the first and second quarters of 2014.

Downstream Capital Expenditures

In the first nine months of 2014, Downstream capital expenditures totalled $347 million compared to $360 million in the same period in 2013. In Canada, capital expenditures of $91 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. At the Lima Refinery, $173 million was spent primarily on the feedstock flexibility project and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $83 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

5.3 Corporate

Corporate Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions) income (expense)	**2014**	2013	**2014**	2013
Administrative expenses	**(16)**	(25)	**(46)**	(95)
Stock-based compensation	**51**	(30)	**(2)**	(32)
Depreciation and amortization	**(18)**	(13)	**(52)**	(34)
Other income (expense)	**(4)**	8	**5**	17
Foreign exchange gains	**31**	7	**46**	9
Interest income (expense)	**(21)**	1	**(48)**	(9)
Income tax recovery (expense)	**(29)**	15	**(23)**	1
Net loss	**(6)**	(37)	**(120)**	(143)

Third Quarter

The Corporate segment reported a loss of $6 million in the third quarter of 2014 compared to a loss of $37 million in the same period in 2013. Stock-based compensation decreased by $81 million in the third quarter of 2014 compared to the same period in 2013 due to the decrease in the Company's share price. Interest expense increased by $22 million in the third 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.

Nine Months

In the first nine months of 2014, the Corporate segment reported a loss of $120 million compared to a loss of $143 million in the same period of 2013. Administrative expenses decreased by $49 million due to lower personnel costs. Stock-based compensation decreased in the first nine months of 2014 compared to the same period in 2013 and interest expense increased in the first nine months of 2014 compared to the same period in 2013 primarily due to the same factors which impacted the third quarter of 2014.

Foreign Exchange Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2014**	2013	**2014**	2013
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(11)**	10	**17**	(11)
Gains (losses) on contribution receivable	**—**	(9)	**7**	21
Gains (losses) on non-cash working capital	**25**	(6)	**25**	19
Other foreign exchange gains (losses)	**17**	12	**(3)**	(20)
Net foreign exchange gains (losses)	**31**	7	**46**	9
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.937**	U.S. $0.951	**U.S. $0.940**	U.S. $1.005
At end of period	**U.S. $0.892**	U.S. $0.972	**U.S. $0.892**	U.S. $0.972

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 third quarter of 2014 was $230 million compared to $184 million in the same period in 2013 resulting in an effective tax rate of 29 percent in the third quarter of 2014 compared to 27 percent in the same period in 2013. The increase in the tax rate was the result of an increase in international activity that is subject to a higher tax rate.

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2014**	2013	**2014**	2013
Income taxes as reported	**230**	184	**753**	688
Cash taxes paid (received)	**145**	(21)	**526**	352

Corporate Capital Expenditures

In the first nine months of 2014, Corporate capital expenditures were $91 million compared to $92 million in the same period of 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 third quarter of 2014, Husky funded its capital programs and dividend payments through cash generated from operating activities, cash on hand, and issuance of commercial paper. At September 30, 2014, Husky had total debt of $4,877 million, partially offset by cash on hand of $893 million, for $3,984 million of net debt compared to $3,022 million of net debt at December 31, 2013. At September 30, 2014, the Company had $3,058 million of unused credit facilities of which $2,630 million is long-term committed credit facilities and $428 million is short-term uncommitted credit facilities. In addition, the Company had $3.0 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 Sept. 30,		Nine months ended Sept. 30,	
($ millions, except ratios)	**2014**	2013	**2014**	2013
Cash flow				
Operating activities	**1,518**	1,276	**4,001**	3,816
Financing activities	**292**	(154)	**(211)**	(589)
Investing activities	**(968)**	(1,280)	**(3,979)**	(3,638)
Financial Ratios[(1)]				
Debt to capital employed *(percent)*[(2)]			**18.7**	16.7
Debt to cash flow *(times)*[(3)(4)]			**0.9**	0.7
Corporate reinvestment ratio *(percent)*[(3)(5)]			**103**	103
Interest coverage ratios on long-term debt only[(3)(6)]				
Earnings			**11.1**	12.9
Cash flow			**21.4**	24.6
Interest coverage ratios on total debt[(3)(7)]				
Earnings			**11.0**	13.0
Cash flow			**21.2**	24.8

(1) Financial ratios constitute non-GAAP measures. Refer to Section 11.
(2) Debt to capital employed is equal to long-term debt and long-term debt due within one year 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 and long-term debt due within one year 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 short and long-term debt.

Cash Flow from Operating Activities

Third Quarter

In the third quarter of 2014, cash flow generated from operating activities was $1,518 million compared to $1,276 million in the same period in 2013 due to a release of non-cash working capital, partially offset by increased cash taxes paid during the period.

Nine Months

In the first nine months of 2014, cash flow generated from operating activities was $4,001 million compared to $3,816 million in the same period in 2013 due to stronger exploration and production earnings and an increase in non-cash depletion, depreciation and amortization, partially offset by higher cash taxes paid.

Cash Flow from (used for) Financing Activities

Third Quarter

In the third quarter of 2014, cash flow from financing activities was $292 million compared to cash flow used for financing activities of $154 million in the same period in 2013 primarily due to the issuance of $600 million in commercial paper in the third quarter of 2014 partially offset by the receipt of the Company's contribution receivable of $176 million in the third quarter of 2013.

Nine Months

Cash flow used for financing activities was $211 million in the first nine months of 2014 compared to $589 million in the same period in 2013 primarily due to the same factors which impacted the third quarter of 2014.

Cash Flow used for Investing Activities

Third Quarter

In the third quarter of 2014, cash flow used for investing activities was $968 million compared to $1,280 million in the same period in 2013. Cash invested in both periods was primarily for capital expenditures.

Nine Months

Cash flow used for investing activities was $3,979 million for the first nine months of 2014 compared to $3,638 million in the same period of 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 and by issuance of short-term commercial paper. 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 September 30, 2014, working capital was $980 million compared to $754 million at December 31, 2013.

During the three months ended June 30, 2014 the Company increased the limit of one of its operating lines from $50 million to $100 million. At September 30, 2014, Husky had unused short and long-term credit facilities totalling $3.1 billion. A total of $217 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit and $600 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.

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 4.00 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 5.90 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 June 19, 2014, the maturity of the $1.6 billion revolving syndicated credit facility previously set to expire on August 31, 2014 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 September 30, 2014 was 1.2%.

Capital Structure	September 30, 2014	
($ millions)	**Outstanding**	**Available**[1]
Total debt	**4,877**	**3,058**
Common shares, preferred shares, retained earnings and other reserves	**21,163**	

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

6.3 Contractual Obligations and Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to Husky's 2013 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2013. During the three months ended September 30, 2014, there were no material changes to non-cancellable commitments.

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 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 and nine months ended September 30, 2014, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $16 million and $59 million, respectively. For the three and nine months ended September 30, 2014, the amount of steam purchased by the Company from Meridian totalled $5 million and $19 million, respectively. In addition, the Company provides facility services to Meridian which are measured at cost. For the three and nine months ended September 30, 2014, the total cost recovery for these services was $2 million and $7 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 September 30, 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 September 30, 2014, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $24 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 $2 million for the three and nine months ended September 30, 2014.

Refer to Note 11 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At September 30, 2014, 84 percent or $3.6 billion of Husky's outstanding 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 September 30, 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 and nine months ended September 30, 2014, the Company incurred unrealized losses of $138 million and $160 million, respectively, arising from the translation of the debt, net of tax of $20 million and $23 million, respectively, which was recorded in net investment hedge 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 September 30, 2014, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At September 30, 2014, the cost of a Canadian dollar in U.S. currency was $0.892.

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 September 30, 2014**	As at December 31, 2013
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**1**	32
Crude oil[(2)]	**(1)**	41
Foreign currency contracts – FVTPL		
Foreign currency forwards	**(3)**	—
Other assets – FVTPL	**2**	2
Contingent consideration	**(37)**	(60)
Hedging instruments[(3)]		
Derivatives designated as a cash flow hedge[(4)]	**—**	37
Hedge of net investment[(5)]	**(253)**	(93)
	(291)	(41)

(1) Natural gas contracts include a $4 million increase as at September 30, 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 $120 million at September 30, 2014.

(2) Crude oil contracts include a $1 million decrease as at September 30, 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 $272 million at September 30, 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.

9. Change in Accounting Policies

The International Accounting Standards Board ("IASB") issued amendments to International Accounting Standards 36, "Impairment of Assets" which was 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.

10. Outstanding Share Data

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

Issued and outstanding: October 20, 2014	
• common shares	983,738,062
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	26,833,284
• stock options exercisable	13,631,106

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 September 30, 2014 are compared to the results for the three months ended September 30, 2013 and the results for the nine months ended September 30, 2014 are compared to the results for the nine months ended September 30, 2013. Discussions with respect to Husky's financial position as at September 30, 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 September 30, 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, adjusted net 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 adjusted net 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 Adjusted Net Earnings

The term "Adjusted Net Earnings" is a non-GAAP measure comprised of net earnings adjusted for certain items not considered indicative of the Company's on-going financial performance. Adjusted net earnings is a complementary measure used in assessing Husky's financial performance through providing comparability between periods.

The following table shows the reconciliation of net earnings to adjusted net earnings and related per share amounts for the three and nine months ended September 30, 2014 and 2013:

		Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)		**2014**	2013	**2014**	2013
GAAP	Net earnings	**571**	512	**1,861**	1,652
	Foreign exchange	**(31)**	(13)	**(42)**	(10)
	Financial instruments	**(2)**	18	**57**	29
	Stock-based compensation	**(51)**	22	**2**	23
	Inventory write downs	**—**	5	**7**	7
Non-GAAP	Adjusted net earnings	**487**	544	**1,885**	1,701
	Adjusted net earnings – basic	**0.50**	0.55	**1.92**	1.73
	Adjusted net earnings – diluted	**0.49**	0.55	**1.91**	1.73

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 and amortization, 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 and nine months ended September 30, 2014 and 2013:

		Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)		**2014**	2013	**2014**	2013
GAAP	Cash flow – operating activities	**1,518**	1,276	**4,001**	3,816
	Settlement of asset retirement obligations	**41**	29	**113**	92
	Income taxes paid	**145**	(21)	**526**	352
	Interest received	**—**	(6)	**(6)**	(14)
	Change in non-cash working capital	**(363)**	69	**(253)**	(167)
Non-GAAP	Cash flow from operations	**1,341**	1,347	**4,381**	4,079
	Cash flow from operations – basic	**1.36**	1.37	**4.45**	4.15
	Cash flow from operations – diluted	**1.36**	1.37	**4.44**	4.15

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

Adjusted Net Earnings	*Net earnings plus after-tax foreign exchange gains and losses, gains and losses from the use of financial instruments, stock-based compensation expense or recovery and any asset impairments and write-downs*
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 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 and long-term debt due within one year divided by capital employed*
Debt to Cash Flow	*Long-term debt and long-term debt due within one year 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*
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 and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

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

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; and the Company's 2014 production guidance, including weighting of production among product types;
- with respect to the Company's Asia Pacific Region: expected timing of design and planning work at the shallow water gas developments in the Madura Strait Block;
- with respect to the Company's Atlantic Region: anticipated timing of development drilling and first production at the Company's South White Rose Extension project; scheduled timing of first production from the North Amethyst Hibernia formation well; scheduled timing for the drilling of an exploration well on the Aster prospect in the Flemish Pass Basin; and scheduled timing and duration for an appraisal and exploration program of the Bay du Nord discovery;
- with respect to the Company's Oil Sands properties: scheduled timing of start up of Plant 1A and 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 heavy oil thermal development; and expected timing of first production and anticipated volumes of production at the Company's Edam East, Edam West and Vawn heavy oil thermal and development projects;
- with respect to the Company's Western Canadian oil and gas resource plays: planned timing of development drilling 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 reconfiguration and the anticipated processing capacity of Western Canadian heavy oil once reconfiguration is complete; and the anticipated benefits from and scheduled timing of completion of a Hydrotreater Recycle Gas Compressor Project 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.