MANAGEMENT'S DISCUSSION AND ANALYSIS

May 6, 2014

Table of Contents

1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Mar. 31**	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30
($ millions, except where indicated)	**2014**	2013	2013	2013	2013	2012	2012	2012
Production *(mboe/day)*	**325.9**	308.3	308.5	309.9	321.3	319.3	285.0	281.9
Gross revenues(1)	**5,943**	6,132	6,036	6,206	5,807	5,889	5,410	5,715
Net earnings	**662**	177	512	605	535	474	526	431
Per share – Basic	**0.67**	0.18	0.52	0.61	0.54	0.48	0.53	0.44
Per share – Diluted	**0.66**	0.18	0.52	0.59	0.54	0.48	0.53	0.43
Cash flow from operations(2)	**1,536**	1,143	1,347	1,449	1,283	1,414	1,271	1,153
Per share – Basic	**1.56**	1.16	1.37	1.47	1.31	1.44	1.29	1.18
Per share – Diluted	**1.56**	1.16	1.37	1.47	1.30	1.44	1.29	1.17

(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

- First quarter production of 325.9 mboe/day was higher compared to the same period in 2013 due to:
  - Commissioning and production ramp-up at the Sandall heavy oil thermal development;
  - Improved operating performance at Terra Nova and production from the multilateral well at North Amethyst brought on stream in the fourth quarter of 2013;
  - Increased oil and liquids-rich natural gas resource play developments;
  - Partially offset by decreased natural gas production due to natural reservoir declines combined with limited re-investment as capital is being directed to higher return oil and liquids-rich natural gas developments.
- Net earnings increased by $127 million or 24 percent to $662 million in the first quarter of 2014 compared to $535 million in the first quarter of 2013. Segment earnings reflect the impact of the focused integration strategy as product and location differentials narrowed in the quarter:
  - Higher average realized Western Canada commodity prices resulting from the narrowing of heavy crude oil and bitumen differentials and improved natural gas pricing combined with a weaker Canadian dollar;
  - Increased crude oil production;
  - Partially offset by a decrease in Upgrading margins due to an increase in heavy crude oil feedstock costs and a decrease in U.S. Refining and Marketing margins due to lower market crack spreads and reduced throughput resulting from a planned turnaround.

- Cash flow from operations increased by $253 million or 20 percent to $1,536 million in the first quarter of 2014 compared to $1,283 million in the first quarter of 2013 mainly due to the same factors which impacted net earnings.

Key Projects

- At the Liwan Gas Project development, first gas from the deep water wells on the Liwan 3-1 gas field was achieved on March 30, 2014 and gas sales to the Guangdong market natural gas grid commenced on April 24, 2014.
- The Sunrise Energy Project remains on track for start up in the second half of 2014. The project is approximately 87 percent complete. Hydro testing of piping and the completion of electrical and instrumentation work and the operations control centre is underway for plant 1A. All well pads have been turned over to operations and are progressing as planned through the commissioning phase.
- Husky and its partner have confirmed plans for an 18-month drilling program at the Bay du Nord discovery in the Flemish Pass Basin, approximately 500 kilometers offshore Newfoundland. The West Hercules drilling rig is scheduled to be available in the region during the third quarter of 2014.
- Husky signed a Production Sharing Contract (“PSC”) for the Anugerah contract area which covers approximately 8,215 square kilometers, primarily offshore East Java, Indonesia, with water depths of up to 1,400 meters.
- The 3,500 bbls/day Sandall heavy oil thermal development began producing crude oil in the first quarter of 2014 with production exceeding the nameplate capacity within one month from first oil and averaging 4,500 bbls/day in March 2014.
- Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected late in 2015.
- At the two 10,000 bbls/day Edam East and Vawn heavy oil thermal development projects, site clearing, detailed engineering and module fabrication is underway with first production expected in 2016.
- Resource play development progressed in Western Canada with 18 oil wells (gross) and 15 liquids-rich natural gas wells (gross) drilled and 22 oil wells (gross) and nine liquids-rich natural gas wells (gross) completed.
- Front-end engineering design ("FEED") on the Lima feedstock flexibility project is approximately 90 percent complete.

Financial

- Dividends on common shares of $295 million for the fourth quarter of 2013 were declared during the first quarter of 2014 and were paid in cash on April 1, 2014.
- The Board of Directors decided to reinstitute the stock dividend program, which allows shareholders to accept dividends declared on the common shares in cash or in common shares.

2. Business Environment

Average Benchmarks		Three months ended Mar. 31, 2014	Dec. 31, 2013	Sept. 30, 2013	Jun. 30, 2013	Mar. 31, 2013
WTI crude oil[(1)]	*(U.S. $/bbl)*	**98.68**	97.46	105.83	94.22	94.37
Brent crude oil[(2)]	*(U.S. $/bbl)*	**108.22**	108.34	108.21	102.52	112.55
Canadian light crude 0.3% sulphur	*($/bbl)*	**89.60**	88.29	104.91	93.78	88.42
Western Canada Select[(3)]	*(U.S. $/bbl)*	**75.55**	65.26	88.35	75.06	62.41
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**72.42**	57.70	86.26	67.24	46.44
NYMEX natural gas[(4)]	*(U.S. $/mmbtu)*	**4.94**	3.61	3.58	4.09	3.34
NIT natural gas	*($/GJ)*	**4.51**	2.99	2.67	3.40	2.92
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**23.09**	32.42	17.50	19.21	32.18
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**20.32**	18.90	17.32	22.49	30.61
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**18.35**	11.91	15.86	30.78	26.87
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.906**	0.953	0.963	0.977	0.991
Canadian $ Equivalents[(5)]						
WTI crude oil	*($/bbl)*	**108.92**	102.26	109.90	96.44	95.23
Brent crude oil	*($/bbl)*	**119.45**	113.68	112.37	104.93	113.57
WTI/Lloyd crude blend differential	*($/bbl)*	**25.49**	34.02	18.17	19.66	32.47
NYMEX natural gas	*($/mmbtu)*	**5.45**	3.79	3.72	4.19	3.37

(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 Region and Asia Pacific Region is referenced to the price of Brent. The price of WTI averaged U.S. $98.68/bbl in the first quarter of 2014 compared to U.S. $94.37/bbl in the first quarter of 2013. The price of Brent averaged U.S. $108.22/bbl in the first quarter of 2014 compared to U.S. $112.55/bbl in the first quarter of 2013.

Crude oil prices realized by the Company in the first quarter of 2014 benefited from the weakening of the Canadian dollar when compared to the first quarter of 2013. In the first quarter of 2014, the price of WTI in U.S. dollars increased 5 percent compared to an increase of 14 percent in Canadian dollars when 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. In the first quarters of both 2014 and 2013, 53 percent of Husky's crude oil production was heavy oil or bitumen. The light/heavy crude oil differential averaged U.S. $23.09/bbl or 23 percent of WTI in the first quarter of 2014 compared to U.S. $32.18/bbl or 34 percent of WTI in the first quarter of 2013.

In the first quarter of 2014, the NYMEX near-month contract price of natural gas averaged U.S. $4.94/mmbtu compared to U.S. $3.34/mmbtu in the first quarter of 2013, an increase of 48 percent. In the first quarter of 2014, the NOVA Inventory Transfer ("NIT") near-month contract price of natural gas averaged $4.51/GJ compared to $2.92/GJ in the first quarter of 2013, an increase of 54 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 first quarter of 2014, the Canadian dollar averaged U.S. $0.906, weakening by 9 percent compared to U.S. $0.991 in the first quarter 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.

In the first quarter of 2014, the Chicago 3:2:1 crack spread averaged U.S. $18.35/bbl compared to U.S. $26.87/bbl in the first quarter of 2013. In the first quarter of 2014, the New York Harbour 3:2:1 crack spread averaged U.S. $20.32/bbl compared to U.S. $30.61/bbl in the first quarter 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 relative annualized effect on earnings before income taxes and net earnings from changes in certain key variables in the first quarter of 2014. The table below reflects what the effect would have been on the financial results for the first quarter of 2014 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the first 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 First 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]	98.68	*U.S. $1.00/bbl*	82	0.08	61	0.06
NYMEX benchmark natural gas price[5]	4.94	*U.S. $0.20/mmbtu*	25	0.03	18	0.02
WTI/Lloyd crude blend differential[6]	23.09	*U.S. $1.00/bbl*	(24)	(0.02)	(18)	(0.02)
Canadian light oil margins	0.046	*Cdn $0.005/litre*	14	0.01	10	0.01
Asphalt margins	28.18	*Cdn $1.00/bbl*	9	0.01	7	0.01
New York Harbour 3:2:1 crack spread	20.32	*U.S. $1.00/bbl*	44	0.04	26	0.03
Exchange rate (U.S. $ per Cdn $)[3][7]	0.906	*U.S. $0.01*	(87)	(0.09)	(64)	(0.06)

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.5 million common shares outstanding as of March 31, 2014.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Excludes impact on asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

3. Strategic Plan

Husky's strategy is to maintain and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward thermal developments and resource plays, while advancing its three major growth pillars in the Asia Pacific Region, the Oil Sands and 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, offshore Indonesia and offshore Taiwan.

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 near-term production growth 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 first quarter of 2014, a total of 18 horizontal wells (gross) were drilled and 22 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 March 31, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	4	5
Lower Shaunavon	S.W. Saskatchewan	—	2
Viking[2]	Alberta and S.W. Saskatchewan	10	8
N.Cardium	Wapiti, Alberta	4	5
Muskwa	Rainbow Region	—	2
Total Gross		18	22
Total Net		18	22

[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.*

In the Northwest Territories, the Slater River Canol shale play all-season road construction is substantially complete and the Company has submitted an application with the regulators to drill and complete up to four horizontal wells at the play.

Liquids-Rich Natural Gas Resource Plays

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

Liquids-Rich Natural Gas Resource Plays - Drilling and Completion Activity[(1)(2)]

		Three months ended March 31, 2014	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	8	3
Duvernay	Kaybob, Alberta	—	2
Wilrich	Kakwa, Alberta	3	—
Strachan Cardium	Rocky Mountain House, Alberta	4	4
Total Gross		15	9
Total Net		13	9

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

The liquids-rich natural gas formations in west central Alberta continue to be a key area of focus for the Company. In the Ansell multi-zone liquids-rich natural gas resource play, eight liquids-rich horizontal natural gas wells (gross) were drilled and three horizontal wells (gross) were completed in the first quarter of 2014. In the Duvernay liquids-rich natural gas resource play at Kaybob, a two-well pad was completed and came on stream in the first quarter of 2014. Average production from the Company's Ansell and Duvernay liquids-rich natural gas resource play developments was 19,000 boe/day in the first quarter of 2014.

Drilling commenced in the first quarter of 2014 at the Wilrich Kakwa liquids-rich natural gas resource play. During the first quarter of 2014, three liquids-rich horizontal natural gas wells (gross) were drilled. The Company and its partner plan to drill a total of five wells (gross) in 2014 at the play.

The Company commenced drilling in late 2013 in the Strachan area located near Rocky Mountain House, Alberta. During the first quarter of 2014, four liquids-rich horizontal natural gas wells (gross) were drilled and completed. Further development drilling is scheduled in 2014.

Conventional Oil and Gas

Approximately 64 wells (gross) were drilled and 46 wells (gross) were completed in the first 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 has been strong with oil rates exceeding nameplate design within one month from first oil and averaging 4,500 bbls/day in March 2014.

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

Site clearing, detailed engineering and module fabrication are underway at the two 10,000 bbls/day Edam East and Vawn thermal development projects with first production expected in 2016.

The Company sanctioned a 3,500 bbls/day thermal project at Edam West, which is scheduled to be brought on production in 2016.

Twenty-three horizontal heavy oil wells (gross) were drilled during the first quarter out of the 140 well program for 2014 compared to 38 heavy oil wells (gross) drilled in the first quarter of 2013.

Seventy-three Cold Heavy Oil Production with Sand ("CHOPS") wells (gross) were drilled during the first quarter out of the 177 well program for 2014 compared to 55 CHOPS wells (gross) drilled in the first quarter of 2013.

Asia Pacific Region

China

Block 29/26

At the Liwan Gas Project development, first gas from the deep water wells on the Liwan 3-1 gas field was achieved on March 30, 2014 and gas sales to the Guangdong market natural gas grid commenced on April 24, 2014.

Short-term customer offtake delays, due to reduced demand from three new gas-fired power plants that are undergoing commissioning and operations start up, will result in some production volumes being deferred.

Negotiations for the sale of gas and liquids from the third deep water field, Liuhua 29-1, are ongoing.

Offshore Taiwan

The acquisition of the second phase two-dimensional seismic survey data on the Company's offshore Taiwan block is planned to commence in the second quarter of 2014.

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 12 percent complete. The last outstanding tender for the BD field floating production, storage and offloading ("FPSO") vessel is awaiting final government approval. Tender plans for the MDA and MBH development projects are under review by SKK Migas, the Indonesia oil and gas regulator. The Government of Indonesia appointed a lead distributor for the majority of the gas to be produced from the MDA and MBH fields and a Heads of Agreement has been signed for the first tranche of gas sales.

During the first quarter, Husky signed a PSC for the Anugerah contract area. The contract area covers approximately 8,215 square kilometers and is primarily offshore East Java, Indonesia, with water depths of up to 1,400 meters. The main prospective locations are in water depths of 800 to 1,300 meters. The contract area is located approximately 150 kilometers east of the Madura Strait Block. Under the PSC, Husky has an obligation to carry out seismic surveys to assess the petroleum potential of the exploration block within the first three years.

Oil Sands

Sunrise Energy Project

Phase 1 of the Sunrise Energy Project remains on track for start up in the second half of 2014. The hydro testing of piping and the completion of electrical and instrumentation work in addition to the operations control centre is underway for plant 1A. All well pads, diluent, diluted bitumen and gathering pipelines are complete and progressing as planned through the commissioning phase.

In the first quarter of 2014, an additional 38 square kilometers of 3-D seismic survey data was acquired and 12 stratigraphic wells were drilled to support continued field development of the Sunrise Energy Project.

Emerging Properties

Husky completed a successful winter delineation program at the McMullen, Caribou and Cadotte North emerging oil sands properties. The winter program at the McMullen oil sands property consisted of the drilling of 40 stratigraphic wells, the acquisition of 25 square kilometers of 3-D seismic survey data and the completion of environmental field study work.

Atlantic Region

White Rose Field and Satellite Extensions

Gas injection commenced during the quarter at the South White Rose Extension. Fabrication of oil production equipment continued, with installation scheduled for the third quarter and first oil anticipated around the end of 2014. Gas injection is expected to increase reservoir pressure and increase oil recovery.

Drilling is set to resume on the North Amethyst Hibernia formation well that will target a deeper zone beneath the main North Amethyst field, with first production planned later in 2014.

Atlantic Exploration

Husky and its partner have confirmed plans for an 18-month drilling program at the Bay du Nord discovery in the Flemish Pass Basin, approximately 500 kilometers offshore Newfoundland. The West Hercules drilling rig is scheduled to be available in the region during the third quarter of 2014. The drilling program will involve the appraisal and delineation of the Bay du Nord discovery as well as exploration of other potential targets. The acquisition of 3-D seismic survey data over the prospect area is scheduled to begin in the second quarter of 2014. Husky holds a 35 percent working interest in the Bay du Nord, Mizzen and Harpoon discoveries.

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 is underway on two 300,000-barrel tanks and additional piping interconnections and is anticipated to be complete in 2015. The project is expected to add approximately 20 percent to existing Husky tank capacity at Hardisty.

The Company completed an expansion of its pipeline system from the Sandall heavy oil thermal development to the existing gathering system that leads to Hardisty, Alberta. In order to accommodate the anticipated increase in production from heavy oil thermal development projects, the Company plans to extend its pipeline systems to expand the South Saskatchewan Gathering System in anticipation of the start up of the Rush Lake, Edam East, Edam West and Vawn heavy oil thermal developments.

4.2 Downstream

Husky Lima, Ohio Refinery

FEED on the Company’s feedstock flexibility project is approximately 90 percent complete. 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 remains 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 progressed on the Hydrotreater Recycle Gas Compressor Project during the first quarter and is scheduled to be completed in 2014. The project is intended to improve operational integrity and plant performance.

5. Results of Operations

5.1 Upstream

Total First Quarter Upstream Earnings 2014 - $422 million, 2013 - $255 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 reflect increased crude oil production and improved Western Canada commodity pricing resulting from narrowing heavy crude oil and bitumen differentials, stronger natural gas pricing and a weaker Canadian dollar compared to the same period in 2013. The increase in net earnings was partially offset by lower marketing margins realized in the first quarter of 2014 compared to the same period in 2013 as a result of the narrowing of product and location differentials between Canada and the United States.

Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	Three months ended March 31, 2014	2013
Gross revenues	**2,182**	1,645
Royalties	**(290)**	(204)
Net revenues	**1,892**	1,441
Purchases, operating, transportation and administrative expenses	**646**	559
Depletion, depreciation and amortization	**573**	562
Exploration and evaluation expenses	**40**	88
Other expenses	**126**	70
Income taxes	**131**	41
Net earnings	**376**	121

Exploration and Production net earnings increased by $255 million in the first quarter of 2014 compared to the first quarter of 2013 primarily due to higher realized crude oil and natural gas prices and increased crude oil production from heavy oil thermal projects, partially offset by higher royalty expense, increased operating costs in Western Canada and an increase in inventory profit not recognized during the quarter due the timing of offshore liftings.

Production increased by 4.6 mboe/day to 325.9 mboe/day in the first quarter of 2014 compared to 321.3 mboe/day in the first quarter of 2013. The increase was primarily due to higher production in Western Canada resulting from the Sandall heavy oil thermal development which commenced production early in the quarter, higher production in the Atlantic Region from the North Amethyst multilateral well which was brought online in late 2013 and improved Terra Nova operating performance. The increase in production was partially offset by natural reservoir declines in natural gas properties as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

The average realized price for crude oil, NGL and bitumen in the first quarter of 2014 was $87.32/bbl compared to $68.32/bbl during the same period in 2013, a 28 percent increase, due to higher Western Canada crude oil prices resulting from narrowing heavy crude oil and bitumen differentials combined with a weaker Canadian dollar. Realized natural gas prices averaged $4.82/mcf in the first quarter of 2014 compared to $3.08/mcf in the same period in 2013, an increase of 56 percent, as a colder winter season led to increased demand and consumption.

Average Sales Prices Realized	Three months ended March 31, 2014	2013
Crude oil and NGL *($/bbl)*		
Light crude oil & NGL	**110.48**	103.59
Medium crude oil	**83.47**	61.74
Heavy crude oil	**72.18**	45.67
Bitumen	**70.78**	43.12
Total average	**87.32**	68.32
Natural gas average *($/mcf)*	**4.82**	3.08
Total average *($/boe)*	**72.21**	54.43

The price realized for Western Canada crude oil reflected narrowing heavy crude oil and bitumen differentials combined with a weaker Canadian dollar. The premium to WTI realized for offshore production reflects Brent prices.

Daily Gross Production	Three months ended March 31, 2014	2013
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**31.4**	30.7
Medium crude oil	**23.7**	23.0
Heavy crude oil	**75.5**	74.4
Bitumen[(1)]	**52.0**	47.9
	182.6	176.0
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**43.7**	43.1
Terra Nova – light crude oil	**6.6**	4.8
	50.3	47.9
China		
Wenchang – light crude oil & NGL	**8.7**	7.8
	241.6	231.7
Natural gas *(mmcf/day)*	**505.9**	537.3
Total *(mboe/day)*	**325.9**	321.3

[(1)] *Bitumen production includes heavy oil thermal average daily gross production of 41.1 mbbls/day for the three months ended March 31, 2014 compared to 37.8 mbbls/day for the three months ended March 31, 2013. Heavy oil thermal production typically receives a higher price than bitumen production.*

Crude Oil and NGL Production

Crude oil and NGL production in the first quarter of 2014 increased by 9.9 mbbls/day or 4 percent compared to the same period in 2013 primarily due to higher production in Western Canada resulting from the Sandall heavy oil thermal development which commenced production early in the quarter, increased production in the Atlantic Region from the North Amethyst multilateral well which was brought online in late 2013 and improved Terra Nova operating performance, partially offset by natural reservoir declines at maturing White Rose fields.

Natural Gas Production

Natural gas production in the first quarter of 2014 decreased by 31.4 mmcf/day or 6 percent compared to the first quarter of 2013 due to natural reservoir declines in 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 three months ended March 31, 2014 and the year ended December 31, 2013, as well as previously issued production guidance for 2014.

		Actual Production	
	2014 Guidance	**Three months ended March 31, 2014**	Year ended December 31, 2013
Crude oil & NGL *(mbbls/day)*			
Light / Medium crude oil & NGL	110 – 115	**114**	104
Heavy crude oil & bitumen	125 – 130	**128**	122
Natural gas Asia Pacific Region *(mboe/day)*	25 – 30	**—**	—
	260 – 275	**242**	226
Natural gas *(mmcf/day)*	420 – 480	**506**	513
Total *(mboe/day)*	330 – 355	**326**	312

Royalties

In the first quarter of 2014, royalty rates as a percentage of gross revenues averaged 14 percent compared to 13 percent in the same period in 2013. Royalty rates in Western Canada averaged 11 percent in the first quarter of 2014 compared to 12 percent in the same period in 2013. Royalty rates for the Atlantic Region averaged 19 percent in the first quarter of 2014 compared to 13 percent in the first quarter of 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 24 percent in the first quarter of 2014 compared to 26 percent in the same period in 2013.

Operating Costs

($ millions)	Three months ended March 31, 2014	2013
Western Canada	**470**	423
Atlantic Region	**57**	43
Asia Pacific Region	**8**	7
Total	**535**	473
Unit operating costs *($/boe)*	**17.21**	15.29

Total Exploration and Production operating costs in the first quarter of 2014 were $535 million compared to $473 million in the same period in 2013. Total unit operating costs in the first quarter of 2014 averaged $17.21/boe compared to $15.29/boe in the same period in 2013.

Operating costs in Western Canada averaged $18.26/boe in the first quarter of 2014 compared to $16.39/boe in the same period in 2013 primarily due to increased natural gas prices and higher energy consumption related to new heavy oil thermal projects and colder weather than normal.

Operating costs in the Atlantic Region averaged $12.59/boe in the first quarter of 2014 compared to $9.98/boe in the same period in 2013. The increase in operating costs was primarily attributable to higher ice management costs resulting from cold temperatures offshore Newfoundland and Labrador in December 2013 and January 2014.

Operating costs in the Asia Pacific Region averaged $10.56/boe in the first quarter of 2014 compared to $9.97/boe in the same period in 2013 due to higher maintenance and servicing costs.

Exploration and Evaluation Expenses

($ millions)	Three months ended March 31, 2014	2013
Seismic, geological and geophysical	**25**	33
Expensed drilling	**12**	52
Expensed land	**3**	3
Exploration and evaluation expenses	**40**	88

Exploration and evaluation expenses in the first quarter of 2014 was $40 million compared to $88 million in the first quarter of 2013. The decrease of $40 million in expensed drilling costs was primarily related to activity in the first quarter of 2013 at the Slater River Canol project where the Company completed the drilling and testing of two vertical wells and completed a baseline groundwater study.

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

In the first quarter of 2014, total DD&A averaged $19.55/boe comparable to $19.46/boe in the first quarter of 2013.

Exploration and Production Capital Expenditures

In the first quarter of 2014, Upstream Exploration and Production capital expenditures were $1,124 million. Capital expenditures were $647 million (58%) in Western Canada, $158 million (14%) in Oil Sands, $161 million (14%) in the Atlantic Region and $158 million (14%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1]	Three months ended March 31,	
($ millions)	**2014**	2013
Exploration		
Western Canada	**54**	110
Oil Sands	**25**	—
Atlantic Region	**7**	5
Asia Pacific Region	**9**	6
	95	121
Development		
Western Canada	**591**	513
Oil Sands	**133**	158
Atlantic Region	**154**	139
Asia Pacific Region	**149**	129
	1,027	939
Acquisitions		
Western Canada	**2**	6
	1,124	1,066

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

Western Canada, Heavy Oil and Oil Sands

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

	Three months ended March 31,			
Wells Drilled		**2014**		2013
(wells) [1]	**Gross**	**Net**	Gross	Net
Exploration				
Oil	**44**	**43**	15	9
Gas	**2**	**2**	5	5
Dry	**—**	**—**	—	—
	46	**45**	20	14
Development				
Oil	**203**	**187**	248	229
Gas	**13**	**11**	35	15
Dry	**—**	**—**	—	—
	216	**198**	283	244
Total	**262**	**243**	303	258

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

The Company drilled 243 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first quarter of 2014 resulting in 230 net oil wells and 13 net natural gas wells compared to 258 net wells resulting in 238 net oil wells and 20 net natural gas wells in the first quarter of 2013.

During the first quarter of 2014, Husky invested $647 million in exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $629 million in the same period in 2013. Property acquisitions totalling $2 million were completed in the first quarter of 2014 compared to $6 million in the same period in 2013. Investment in oil and natural gas exploration and development in the first quarter of 2014 was $148 million and $174 million, respectively, compared to $185 million and $175 million, respectively, in the first quarter of 2013. Investment in natural gas was primarily directed at liquids-rich natural gas resource plays.

In addition, $56 million was spent on production optimization and cost reduction initiatives in the first quarter of 2014 compared to $37 million in the same period in 2013. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $101 million in the first quarter of 2014 compared to $93 million in the same period in 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $166 million in the first quarter of 2014 compared to $133 million in the same period in 2013.

Oil Sands

In both the first quarter of 2014 and 2013, $158 million was invested in Oil Sands projects, primarily on the development of Phase 1 of the Sunrise Energy Project. In addition, the Company completed a winter delineation program at the McMullen emerging oil sands property in the first quarter of 2014.

Atlantic Region

During the first quarter of 2014, $161 million was invested in Atlantic Region projects, compared to $144 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 quarter of 2014, $158 million was invested in Asia Pacific Region projects, compared to $135 million in the same period in 2013, primarily on the continued development of the Liwan Gas Project.

Upstream Planned Turnarounds

Planned plant maintenance activities for Western Canada are scheduled in the second and third quarters of 2014 including the full shutdown and maintenance of the Rainbow oil and gas facility for approximately four weeks in the second quarter.

The planned offstation of the Wenchang FPSO commenced on April 6, 2014 and is expected to last for approximately five months. The offstation is intended to address dry dock maintenance and mooring line replacement.

In the Atlantic Region, the partner-operated Terra Nova FPSO is scheduled to undergo a four week turnaround in the third quarter of 2014.

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 March 31,	
($ millions, except where indicated)	**2014**	2013
Infrastructure gross margin	**44**	32
Marketing and other gross margin	**34**	162
Gross margin	**78**	194
Operating and administrative expenses	**10**	9
Depletion, depreciation and amortization	**7**	6
Income taxes	**15**	45
Net earnings	**46**	134
Commodity trading volumes managed *(mboe/day)*	**282.5**	180.5

Infrastructure and Marketing net earnings in the first quarter of 2014 decreased by $88 million compared to the same period in 2013 as a result of the narrowing of product and location differentials between Canada and the United States. In addition, increased volatility of market prices for natural gas in the first quarter of 2014 compared to the same period in 2013 resulted in current period higher unrealized mark to market losses on forward natural gas contracts which will reverse as the contracts reach maturity.

5.2 Downstream

Total First Quarter Downstream Earnings 2014 - $259 million, 2013 - $352 million

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing. Net earnings on a combined basis reflect weaker Upgrading and U.S. Refining and Marketing net earnings. The decrease in Upgrading net earnings was primarily due to the impact of significantly lower upgrading differentials resulting from higher priced Lloyd Heavy Blend crude oil feedstock. The decrease in U.S. Refining and Marketing net earnings was attributed to lower throughput resulting from a planned turnaround initiated at the Lima Refinery. Lower market crack spreads were offset by FIFO gains and the production of higher value products.

Upgrader

Upgrader Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2014**	2013
Gross revenues	**573**	529
Gross margin	**189**	242
Operating and administrative expenses	**49**	39
Depreciation and amortization	**24**	24
Other expenses	**9**	1
Income taxes	**28**	46
Net earnings	**79**	132
Upgrader throughput *(mbbls/day)*[(1)]	**72.4**	74.2
Synthetic crude oil sales *(mbbls/day)*	**53.9**	56.1
Upgrading differential *($/bbl)*	**27.40**	38.51
Unit margin *($/bbl)*	**38.96**	47.93
Unit operating cost *($/bbl)*[(2)]	**7.21**	5.84

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

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 in the first quarter of 2014 were $79 million compared to $132 million in the same period in 2013. The decrease was primarily due to lower average upgrading differentials, lower sales volumes and higher operating costs resulting from increased energy and maintenance costs.

During the first quarter of 2014, the upgrading differential averaged $27.40/bbl, a decrease of $11.11/bbl or 29 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 higher heavy oil feedstock costs partially offset by higher prices for synthetic crude oil. The average price for Husky Synthetic Blend in the first quarter of 2014 was $106.26/bbl compared to $95.43/bbl in the same period in 2013. The overall unit margin decreased to $38.96/bbl in the first quarter of 2014 from $47.93/bbl in the same period in 2013.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2014**	2013
Gross revenues	**939**	843
Gross margin		
Fuel	**32**	36
Refining	**81**	48
Asphalt	**61**	84
Ancillary	**14**	13
	188	181
Operating and administrative expenses	**73**	58
Depreciation and amortization	**24**	22
Income taxes	**23**	26
Net earnings	**68**	75
Number of fuel outlets(1)	**503**	513
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*(2)	**7.7**	8.2
Fuel sales per retail outlet *(thousands of litres/day)*(2)	**13.4**	13.4
Refinery throughput		
Prince George refinery *(mbbls/day)*	**12.0**	11.2
Lloydminster refinery *(mbbls/day)*	**29.0**	28.3
Ethanol production *(thousands of litres/day)*	**789.3**	783.3

(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.*

Fuel gross margins were lower in the first quarter of 2014 compared to the same period in 2013 due to lower diesel margins and lower sales volumes resulting from selected outlet closures.

Refining gross margins were higher in the first quarter of 2014 compared to the same period in 2013 primarily due to higher sales volumes, partially offset by higher feedstock costs at the Prince George Refinery, and lower feedstock costs at the Lloydminster and Minnedosa Ethanol plants.

Asphalt gross margins were lower in the first quarter of 2014 compared to the same period in 2013 due to higher heavy crude oil feedstock costs, partially offset by higher sales volumes.

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

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2014**	2013
Gross revenues	**2,420**	2,711
Gross refining margin	**364**	386
Operating and administrative expenses	**124**	105
Depreciation and amortization	**61**	57
Other expenses	**1**	1
Income taxes	**66**	78
Net earnings	**112**	145
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**110.5**	146.9
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**65.5**	66.3
Refining margin *(U.S. $/bbl crude throughput)*	**21.63**	20.47
Refinery inventory *(mmbbls)*(1)	**9.9**	10.9

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

U.S. Refining and Marketing net earnings decreased in the first quarter of 2014 compared to the same period in 2013 primarily due to lower market crack spreads, offset by FIFO gains and production of higher value products, and reduced throughput resulting from a planned turnaround at the Lima Refinery which also resulted in higher operating costs.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out 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 lower. The estimated FIFO impact was an increase in net earnings of approximately $63 million in the first quarter of 2014 compared to an increase in net earnings of $10 million in the same period in 2013.

A planned maintenance outage was initiated at the Lima Refinery in mid-March and was completed in April. The maintenance work completed was performed in preparation for the major turnaround planned for 2015.

In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10% to 15% 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.

Downstream Capital Expenditures

In the first quarter of 2014, Downstream capital expenditures totalled $114 million compared to $52 million in the same period in 2013. In Canada, capital expenditures of $39 million were related to projects at the Upgrader and the Prince George Refinery. At the Lima Refinery, $44 million was spent primarily on the feedstock flexibility project and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $31 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Upgrader is scheduled to undergo a partial outage in the fall of 2014 for planned maintenance. Plant rates are expected to remain at approximately 80 percent during the planned 42-day turnaround.

The BP-Husky Toledo Refinery commenced a planned turnaround late in the first quarter of 2014 that affects approximately 30 percent of its operating capacity.

5.3 Corporate

Corporate Summary	Three months ended March 31,	
($ millions) income (expense)	**2014**	2013
Administrative expenses	**(18)**	(43)
Stock-based compensation	**(6)**	(9)
Depreciation and amortization	**(16)**	(10)
Other income	**—**	14
Foreign exchange gain (loss)	**18**	(8)
Interest – net	**7**	(9)
Income taxes	**(4)**	(7)
Net loss	**(19)**	(72)

The Corporate segment reported a loss of $19 million in the first quarter of 2014 compared to a loss of $72 million in the same period in 2013. Administrative expenses decreased by $25 million compared to the same period in 2013 due to higher software and information technology project expenses recognized in the first quarter of 2013 and a decrease in personnel costs during the first quarter of 2014. Depreciation and amortization increased by $6 million compared to the same period in 2013 due to a higher capital base primarily related to expenditures on computer hardware and software and leasehold improvements. Other income decreased by $14 million compared to the same period in 2013 due to a recovery of insurance premiums in the first quarter of 2013. Foreign exchange was a gain of $18 million compared to a loss of $8 million in the same period in 2013 due to a weakening of the Canadian dollar against the U.S. dollar which impacted the translation of the Company's foreign currency denominated working capital. Net interest increased by $16 million compared to the same period in 2013 due to an increase in capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project, partially offset by a decrease in finance income related to the Company's contribution receivable.

Foreign Exchange Summary	Three months ended March 31,	
($ millions, except where indicated)	**2014**	2013
Gains (losses) on translation of U.S. dollar denominated long-term debt	**—**	(8)
Gains on contribution receivable	**7**	14
Other foreign exchange gains (losses)	**11**	(14)
Net foreign exchange gains (losses)	**18**	(8)
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $0.940**	U.S. $1.005
At end of period	**U.S. $0.905**	U.S. $0.985

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 increased in the first quarter of 2014 to $267 million from $243 million in the same period in 2013 resulting in an effective tax rate of 29 percent in the first quarter of 2014 and 31 percent in the same period in 2013. Cash taxes in the quarter reflect refunds and adjustments related to 2013.

	Three months ended March 31,	
($ millions)	**2014**	2013
Income taxes as reported	**267**	243
Cash taxes paid	**96**	141

Corporate Capital Expenditures

In the first quarter of 2014, Corporate capital expenditures were $31 million compared to $23 million in the same period in 2013 primarily related to computer hardware and software and leasehold improvements.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the first quarter of 2014, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At March 31, 2014, Husky had total debt of $5,068 million partially offset by cash on hand of $1,518 million for $3,550 million of net debt compared to $3,022 million of net debt at December 31, 2013. At March 31, 2014, the Company had $3.6 billion of unused credit facilities of which $3.2 billion was long-term committed credit facilities and $369 million was 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 March 31,	
($ millions, except ratios)	**2014**	2013
Cash flow		
Operating activities	**1,336**	1,315
Financing activities	**655**	(205)
Investing activities	**(1,573)**	(1,234)
Financial Ratios[(1)]		
Debt to capital employed *(percent)*[(2)]	**19.8**	17.0
Debt to cash flow *(times)*[(3)(4)]	**0.9**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]	**105**	106
Interest coverage ratios on long-term debt only[(3)(6)]		
Earnings	**11.6**	12.2
Cash flow	**22.3**	23.9
Interest coverage on ratios of total debt[(3)(7)]		
Earnings	**11.7**	12.1
Cash flow	**22.5**	23.6

(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

In the first quarters of 2014 and 2013, cash generated from operating activities was $1.3 billion. An increase in exploration and production earnings during the first quarter of 2014 was offset by an increase in non-cash working capital resulting from the timing of accounts receivable settlements and inventory movement.

Cash Flow from (used for) Financing Activities

In the first quarter of 2014, cash generated from financing activities was $655 million compared to cash flow used for financing activities of $205 million in the same period in 2013. The change was primarily due to the issuance of U.S. $750 million in senior unsecured notes completed in the first quarter of 2014 to fund the repayment of U.S. $750 million senior unsecured notes maturing in June 2014.

Cash Flow used for Investing Activities

In the first quarter of 2014, cash used for investing activities was $1.6 billion compared to $1.2 billion in the same period in 2013. Cash invested in both periods was primarily for capital expenditures.

6.2 Sources of Capital

Husky is currently able to fund its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of long-term debt and borrowings under committed and uncommitted credit facilities. 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 March 31, 2014, working capital was $1,154 million compared to $754 million at December 31, 2013. The increase in working capital was mainly attributable to strong cash flows from operations in the quarter and the issuance of U.S. $750 million in senior unsecured notes.

At March 31, 2014, Husky had unused short and long-term credit facilities totalling $3.6 billion. A total of $225 million of the Company's short-term credit facilities was used in support of outstanding letters of credit.

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 unless the notes are redeemed in 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.

Capital Structure		**March 31, 2014**
($ millions)	**Outstanding**	**Available**[(1)]
Total long-term debt	**5,068**	**3,568**
Common shares, preferred shares, retained earnings and other reserves	**20,535**	

(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.

As at March 31, 2014, the Company had the following material changes to non-cancellable commitments:

- 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.
- During the first quarter of 2014, the Company's non-cancellable building leases increased by $687 million primarily due to the renewal of its corporate office lease agreement partially offset by decreases in satellite office future lease payments.
- The Company's take or pay crude oil non-cancellable commitments have decreased by approximately $1.1 billion due to a decrease in tariff rates associated with a delay in pipeline availability.

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

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 months ended March 31, 2014, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $22 million. For the three months ended March 31, 2014, the amount of steam purchased by the Company from Meridian totalled $8 million. The Company provides facility services to Meridian which are measured at cost. For the three months ended March 31, 2014, the total cost recovery for these services was $2 million.

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 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 March 31, 2014, the Company was party to crude oil purchase and sale derivative contracts to mitigate its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company was also party to third party physical natural gas purchase and sale derivative contracts in order to mitigate the impact of 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 three months ended March 31, 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 during the period. Accordingly, the accrued gain in other reserves is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship were originally designated. The amortization period is ten years.

At March 31, 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 $25 million (December 31, 2013 – $37 million), net of tax of $9 million (December 31, 2013 - net of tax of $13 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in offsets to finance expenses of less than $1 million for the three months ended March 31, 2014.

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

Foreign Currency Risk Management

At March 31, 2014, 86 percent or $4.4 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, 16 percent of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At March 31, 2014, the Company had designated U.S. $3.2 billion of its U.S. denominated debt as a hedge of the Company's net investment in its U.S. refining operations. For the three months ended March 31, 2014, the Company incurred an unrealized loss of $116 million arising from the translation of the debt, net of tax of $17 million, which was recorded in other comprehensive income ("OCI").

Husky holds 50 percent of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and a major portion of this receivable is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange in current period earnings. At March 31, 2014, Husky's share of this receivable was U.S. $5 million including accrued interest. 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 March 31, 2014, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At March 31, 2014, the cost of a Canadian dollar in U.S. currency was $0.9047.

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)*	**March 31, 2014**	December 31, 2013
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**(5)**	32
Crude oil[(2)]	**9**	41
Foreign currency contracts – FVTPL		
Foreign currency forwards	**—**	—
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)]	**(209)**	(93)
	(240)	(41)

[(1)] *Natural gas contracts includes a $2 million decrease as at March 31, 2014 (December 31, 2013 – $27 million increase) to the fair value of held-for-trading inventory, recognized in the condensed interim consolidated balance sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $76 million at March 31, 2014.*

[(2)] *Crude oil contracts includes a $14 million increase as at March 31, 2014 (December 31, 2013 – $49 million increase) to the fair value of held-for-trading inventory recognized in the condensed interim consolidated balance sheets related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $406 million at March 31, 2014.*

[(3)] *Hedging instruments are presented net of tax.*

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

[(5)] *Represents the translation of the Company's U.S. 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 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 consolidated financial statements.

10. Outstanding Share Data

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

Issued and outstanding: May 1, 2014	
• common shares	983,510,449
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	31,754,956
• stock options exercisable	15,078,748

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

Additional Reader Guidance

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

Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this MD&A and related disclosures are cash flow from operations, 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. With the exception of adjusted net earnings and cash flow from operations, there are no comparable measures in accordance with IFRS. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. 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 months ended March 31, 2014 and 2013:

		Three months ended March 31,	
($ millions)		**2014**	2013
GAAP	Net earnings	**662**	535
	Foreign exchange	**(10)**	6
	Mark to market on forward commodity price contracts	**51**	(1)
	Stock-based compensation	**6**	7
	Inventory write downs	**7**	—
Non-GAAP	Adjusted net earnings	**716**	547
	Adjusted net earnings – basic	**0.73**	0.56
	Adjusted net earnings – diluted	**0.73**	0.56

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 months ended March 31, 2014 and 2013:

		Three months ended March 31,	
($ millions)		**2014**	2013
GAAP	Cash flow – operating activities	**1,336**	1,315
	Settlement of asset retirement obligations	**49**	43
	Income taxes paid	**96**	141
	Interest received	**(3)**	(3)
	Change in non-cash working capital	**58**	(213)
Non-GAAP	Cash flow from operations	**1,536**	1,283
	Cash flow from operations – basic	**1.56**	1.31
	Cash flow from operations – diluted	**1.56**	1.30

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*	*thousand barrels*
boe	*barrels of oil equivalent*	*mbbls/day*	*thousand barrels per day*
CHOPS	*cold heavy oil production with sand*	*mboe*	*thousand barrels of oil equivalent*
CPF	*Central Processing Facility*	*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*

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 amount by product types;
- with respect to the Company's Asia Pacific Region: anticipated deferral of some production volumes resulting from short-term customer offtake delays; expected timing of completion of the acquisition of a seismic survey at the Company's offshore Taiwan exploration block; and expected duration and intended impact of the planned offstation of the Wenchang FPSO;
- with respect to the Company's Atlantic Region: anticipated benefits of gas injection, expected timing of installation of oil production equipment and anticipated timing of first production at the Company's South White Rose Extension project; planned resumption of drilling and anticipated timing of first production from the North Amethyst Hibernia formation well; plans for a drilling program in the Flemish Pass Basin and anticipated timing of acquisition of seismic data for the prospect area; and scheduled timing and duration of a planned turnaround at the Terra Nova FPSO;
- with respect to the Company's Oil Sands properties: scheduled timing of start up 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; expected timing of first production and anticipated volumes of production at the Company's Edam East, Edam West and Vawn heavy oil thermal developments; and the Company's horizontal and CHOPS drilling program for 2014;
- with respect to the Company's Western Canadian oil and gas resource plays: drilling plans at the Wilrich Kakwa and Strachan Cardium liquids rich natural gas projects; and the timing and duration of a planned turnaround at the Rainbow oil and gas facility;
- with respect to the Company's Infrastructure and Marketing operating segment: expected timing of completion of and anticipated benefits from the Hardisty terminal expansion project; and plans to expand the South Saskatchewan Gathering System for the Rush Lake, Edam East, Edam West and Vawn heavy oil thermal developments; and

- with respect to the Company's Downstream operating segment: the anticipated benefits from the Lima, Ohio feedstock flexibility project and the anticipated processing capacity once reconfiguration is complete; scheduled timing, duration and expected impact of a partial outage of the Lloydminster Upgrader for planned maintenance; the anticipated benefits from and scheduled timing of completion of a Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; and scheduled timing of a major turnaround at the Lima 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.