MANAGEMENT'S DISCUSSION AND ANALYSIS

May 5, 2015

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)	**2015**	2014	2014	2014	2014	2013	2013	2013
Production *(mboe/day)*	**356.0**	359.6	341.1	333.6	325.9	308.3	308.5	309.9
Gross revenues	**4,086**	5,875	6,690	6,614	5,943	6,132	6,036	6,206
Net earnings (loss)	**191**	(603)	571	628	662	177	512	605
Per share – Basic	**0.19**	(0.62)	0.58	0.63	0.67	0.18	0.52	0.61
Per share – Diluted	**0.17**	(0.65)	0.52	0.63	0.66	0.18	0.52	0.59
Adjusted net earnings[(1)]	**191**	147	571	628	669	375	517	607
Cash flow from operations[(1)]	**838**	1,145	1,341	1,504	1,536	1,143	1,347	1,449
Per share – Basic	**0.85**	1.16	1.36	1.53	1.56	1.16	1.37	1.47
Per share – Diluted	**0.85**	1.16	1.36	1.52	1.56	1.16	1.37	1.47

[(1)] *Adjusted net earnings and cash flow from operations are non-GAAP measures. Adjusted net earnings was redefined in the first quarter of 2015 to equal net earnings before after-tax property, plant and equipment impairment and after-tax inventory write-downs. Refer to Section 11 for a reconciliation to the GAAP measures.*

Performance

- Production increased by 30.1 mboe/day or nine percent to 356.0 mboe/day in the first quarter of 2015 compared to the first quarter of 2014 as a result of:
  - Production from the Liwan Gas Project which continued to increase in the quarter;
  - Increased production from the Ansell liquids-rich natural gas resource play; and
  - Strong production performance from heavy oil thermal developments;
  - Partially offset by natural reservoir declines at mature properties in Western Canada and the Atlantic Region.
- Cash flow from operations of $838 million in the first quarter of 2015 compared to $1,536 million in the first quarter of 2014 with the decrease due to the same factors noted below which impacted net earnings.
- Net earnings of $191 million included recognition of a deferred income tax recovery of $203 million as a result of the partial payment of the contribution payable to BP-Husky Refining LLC. Other factors impacting net earnings in the first quarter of 2015 were:
  - Lower realized crude oil prices and North American natural gas prices resulting from a 50 percent decline in market benchmarks; and
  - Lower U.S. Refining and Marketing margins resulting from a drop in market crack spreads together with declining crude oil prices and unplanned outages at both the Lima and BP-Husky Toledo Refineries;
  - Partially offset by higher realized natural gas prices in the Asia Pacific Region due to fixed prices on production from the Liwan Gas Project; and
  - A weaker Canadian Dollar.

Key Projects

- First oil was achieved on phase 1 at the Sunrise Energy Project in March 2015 with production from the project expected to ramp-up to 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016.
- At the Liwan Gas Project, combined gross production and sales from the Liwan 3-1 and Liuhua 34-2 gas fields continued to increase during the first quarter of 2015. Market opportunities for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, are being pursued.
- In 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 39 percent complete and construction of the FPSO vessel has commenced.
- In the Atlantic Region, development drilling continued on the first production wells for the South White Rose Extension, with first oil anticipated in mid-2015.
- Drilling of the Hibernia-formation well at the North Amethyst field is scheduled to resume after the first two South White Rose production wells have been brought online in mid-year. First production from the well is expected in the third quarter of 2015.
- Commissioning is underway at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the third quarter of 2015.
- Construction work continued at the two 10,000 bbls/day Edam East and Vawn and the 4,500 bbls/day Edam West thermal developments with first production from all three developments expected in the second half of 2016. Anticipated capacity at the Edam West heavy oil thermal project has been increased from 3,500 bbls/day to 4,500 bbls/day through design and efficiency improvements.
- Western Canada liquids-rich gas resource play development progressed in the first quarter of 2015 with 12 wells (gross) drilled and nine wells (gross) completed including continued development of the Ansell liquids-rich natural gas resource play.
- The Hardisty terminal expansion project is now complete and operational.

Financial

- Dividends on common shares of $295 million for the fourth quarter of 2014 were declared during the first quarter of 2015, of which $292 million and $3 million were paid in cash and common shares, respectively, on April 1, 2015.

2. Business Environment

Average Benchmarks		Three months ended Mar. 31, 2015	Dec. 31, 2014	Sept. 30, 2014	Jun. 30, 2014	Mar. 31, 2014
WTI crude oil[(1)]	*(U.S. $/bbl)*	**48.63**	73.15	97.17	102.99	98.68
Brent crude oil[(2)]	*(U.S. $/bbl)*	**53.97**	76.27	101.85	109.61	108.22
Canadian light crude 0.3% sulphur	*($/bbl)*	**40.19**	65.90	88.53	96.29	89.60
Western Canada Select[(3)]	*(U.S. $/bbl)*	**33.90**	58.90	76.99	82.95	75.55
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**36.41**	61.77	77.96	80.98	72.42
NYMEX natural gas[(4)]	*(U.S. $/mmbtu)*	**2.98**	4.00	4.06	4.67	4.94
NIT natural gas	*($/GJ)*	**2.80**	3.80	4.00	4.44	4.51
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**14.63**	14.14	20.23	20.17	23.09
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**19.33**	16.09	18.86	19.27	20.32
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**16.14**	14.04	17.41	19.40	18.35
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.806**	0.881	0.918	0.917	0.906
Canadian $ Equivalents[(5)]						
WTI crude oil	*($/bbl)*	**60.33**	83.03	105.85	112.31	108.92
Brent crude oil	*($/bbl)*	**66.96**	86.57	110.95	119.53	119.45
WTI/Lloyd crude blend differential	*($/bbl)*	**18.15**	16.05	22.04	22.00	25.49
NYMEX natural gas	*($/mmbtu)*	**3.70**	4.54	4.42	5.09	5.45

(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 Canada 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. Crude oil prices dropped by more than 50 percent at the end of 2014 and continued to be significantly weaker than the prior year throughout the first quarter of 2015. The price of WTI averaged U.S. $48.63/bbl in the first quarter of 2015 compared to U.S. $98.68/bbl in the first quarter of 2014. The price of Brent averaged U.S. $53.97/bbl in the first quarter of 2015 compared to U.S. $108.22/bbl in the first quarter of 2014.

Crude oil prices realized by the Company in the first quarter of 2015 benefited significantly from the weakening of the Canadian dollar when compared to the first quarter of 2014. In the first quarter of 2015, the price of WTI in U.S. dollars decreased 51 percent compared to a decrease of 45 percent in Canadian dollars when compared to the first quarter of 2014.

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 quarter of 2015, 54 percent of Husky's crude oil production was heavy oil or bitumen compared with 53 percent in the first quarter of 2014. The light/heavy crude oil differential averaged U.S. $14.63/bbl or 30 percent of WTI in the first quarter of 2015 compared to U.S. $23.09/bbl or 23 percent of WTI in the first quarter of 2014.

In the first quarter of 2015, the NYMEX near-month contract price of natural gas averaged U.S. $2.98/mmbtu compared to U.S. $4.94/mmbtu in the first quarter of 2014, a decrease of 40 percent. In the first quarter of 2015, the NOVA Inventory Transfer ("NIT") near-month contract price of natural gas averaged $2.80/GJ compared to $4.51/GJ in the first quarter of 2014, a decrease of 38 percent.

Accelerated growth of global crude oil and natural gas production and inventory supplies relative to demand, resulting primarily from the growth in U.S. unconventional production, led to the sharp decline in key crude oil and natural gas benchmarks in the first quarter of 2015 compared to the same period in 2014.

Foreign Exchange

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

In the first quarter of 2015, the Canadian dollar averaged U.S. $0.806, weakening by 11 percent compared to U.S. $0.906 in the first quarter of 2014.

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 2015, the Chicago 3:2:1 crack spread averaged U.S. $16.14/bbl compared to U.S. $18.35/bbl in the first quarter of 2014. In the first quarter of 2015, the New York Harbour 3:2:1 crack spread averaged U.S. $19.33/bbl compared to U.S. $20.32/bbl in the first quarter of 2014.

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 of changes in certain key variables in the first quarter of 2015 on earnings before income taxes and net earnings. The table below reflects what the effect would have been on the financial results for the first quarter of 2015 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the first quarter of 2015. 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	**2015 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]	**48.63**	*U.S. $1.00/bbl*	**91**	**0.09**	**67**	**0.07**
NYMEX benchmark natural gas price[5]	**2.98**	*U.S. $0.20/mmbtu*	**39**	**0.04**	**30**	**0.03**
WTI/Lloyd crude blend differential[6]	**14.63**	*U.S. $1.00/bbl*	**(24)**	**(0.02)**	**(19)**	**(0.02)**
Canadian light oil margins	**0.048**	*Cdn $0.005/litre*	**14**	**0.01**	**10**	**0.01**
Asphalt margins	**19.76**	*Cdn $1.00/bbl*	**9**	**0.01**	**7**	**0.01**
New York Harbour 3:2:1 crack spread	**19.33**	*U.S. $1.00/bbl*	**41**	**0.04**	**24**	**0.02**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.806**	*U.S. $0.01*	**(50)**	**(0.05)**	**(37)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.8 million common shares outstanding as of March 31, 2015.*
(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 growth in the Asia Pacific Region, the Oil Sands and the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids (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). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, offshore the 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). Upgrading, Canadian Refined Products and U.S. Refining and Marketing process and refine natural resources into marketable products and therefore, were grouped together as the Downstream business segment due to the similar nature of products and services.

4. Key Growth Highlights

The 2015 Capital Program enables Husky to build on the momentum achieved over the past five years while maintaining prudent capital management and pacing the Company's growth projects and exploration plans in a weak commodity price environment.

4.1 Upstream

Western Canada (Excluding Heavy Oil and Oil Sands)

Liquids-Rich Natural Gas Resource Plays

In the first quarter of 2015, 12 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 in Key Plays[(1)(2)]

Project	Location	Three months ended March 31, 2015 Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	8	8
Wilrich	Kakwa, Alberta	1	1
Strachan Cardium	Rocky Mountain House, Alberta	3	—
Total Gross		12	9
Total Net		8	8

(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, eight horizontal wells (gross) were drilled and eight horizontal wells (gross) were completed in the first quarter of 2015. Average production from the play was approximately 19,300 boe/day.

Development continued on the Strachan liquids-rich natural gas resource play near Rocky Mountain House with three wells (gross) drilled in the first quarter of 2015. Production results from the play are in line with expectations.

Oil Resource Plays and Conventional

Oil related drilling and completion activity in Western Canada has been substantially curtailed in the first quarter of 2015 and is not expected to resume for the balance of the year.

Heavy Oil

Heavy Oil Thermal Developments

The Company continued to advance a strong lineup of heavy oil thermal developments. These long-life developments are being built with modular, repeatable designs and are expected to require low sustaining capital once brought online. Total heavy oil thermal production in the first quarter averaged 45,500 bbls/day.

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	First production Expected
Rush Lake Commercial	10,000	90%	Q3 2015
Edam East	10,000	49%	Q3 2016
Vawn	10,000	38%	Q4 2016
Edam West	4,500	21%	Q4 2016

At the 10,000 bbls/day Rush Lake Commercial heavy oil thermal development, construction is approximately 90 percent complete. Commissioning is currently underway with first production expected in the third quarter of 2015.

At the 10,000 bbls/day Edam East and 10,000 bbls/day Vawn heavy oil thermal developments, construction is approximately 49 and 38 percent complete, respectively. Civil construction is now complete, major equipment is being delivered and mechanical and electrical Central Processing Facility construction is progressing at both projects with first production expected in the third quarter of 2016 at Edam East and in the fourth quarter of 2016 at Vawn.

Capacity at the Edam West heavy oil thermal development has been increased from 3,500 bbls/day to 4,500 bbls/day through design and efficiency improvements and construction is approximately 21 percent complete. Detailed engineering is progressing and civil construction commenced in the first quarter of 2015. First production is expected in the fourth quarter of 2016.

At the Sandall heavy oil thermal development, production continues to be strong with oil rates averaging 5,600 bbls/day in the first quarter of 2015. The Sandall heavy oil thermal development, originally designed to produce 3,500 bbls/day, began producing crude oil in the first quarter of 2014.

Several other Heavy Oil Thermal projects are in the pre-development phase.

Emerging Heavy Oil Thermal Development

A five well drilling program was completed at the McMullen thermal development during the first quarter of 2015, and the results were in-line with expectations. Engineering work is ongoing to define the scope for a 10,000 bbls/day Cyclic Steam Stimulation commercial demonstration project.

Conventional Heavy Oil

Three horizontal heavy oil wells (gross) were drilled during the first quarter of 2015.

Asia Pacific Region

China

Block 29/26

Combined gross production from the Liwan 3-1 and Liuhua 34-2 gas fields increased from 240 mmcf/day in the fourth quarter of 2014 to 262 mmcf/day in the first quarter of 2015. Gross sales of associated natural gas liquids increased from approximately 11.3 mboe/day to 13.6 mboe/day over the same period. Market opportunities for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, are being pursued.

Offshore Taiwan

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

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block. Work related to the BD field engineering, procurement, installation and construction contract is ongoing and approximately 39 percent complete, and construction of the FPSO vessel has commenced.

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

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

Oil Sands

Sunrise Energy Project
First oil was achieved on phase 1 at the Sunrise Energy Project in March 2015 with production from the project expected to ramp up to 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016. Production sales are planned for the second quarter of 2015.

The Company is utilizing a custom drilling rig to improve drilling efficiencies and reduce costs. The rig provides for the closer spacing of wellheads, smaller drilling pads and fewer pad facilities.

Atlantic Region

White Rose Field and Satellite Extensions
Development drilling continued on the first production wells for the South White Rose Extension with first oil anticipated in mid-2015.

The Company continues to evaluate the development of the West White Rose Extension using either a wellhead platform or subsea development scheme for full field development.

Drilling of the Hibernia-formation well at the North Amethyst field is scheduled to resume after the first two South White Rose production wells have been brought online in mid-year. First production from the well is expected in the third quarter of 2015.

Atlantic Exploration
The semi-submersible drilling rig West Hercules continued with the exploration and appraisal program at the Bay du Nord discovery area offshore Newfoundland and Labrador. A planned sidetrack of the first appraisal well was completed and drilling of the second well commenced in the first quarter of 2015.

Infrastructure and Marketing

The Hardisty terminal expansion project is complete and operational. The project included multiple initiatives to increase pipeline connectivity, blending capacity and product storage to support upstream production growth and provide additional flexibility in marketing the Company's products.

Construction is ongoing for the expansion of the Saskatchewan Gathering System which will create incremental capacity to accommodate planned production from the Rush Lake, Edam East, Vawn and Edam West thermal developments. Construction is approximately 35 percent complete.

4.2 Downstream

Husky Lima, Ohio Refinery
Engineering and construction of the crude oil flexibility project has been deferred until the 2018-19 time frame.

BP-Husky Toledo, Ohio Refinery
The Company has commenced construction to address updated flare stack regulatory monitoring and emission standards coming into effect during the fourth quarter of 2015. Husky expects the work to be completed by the fourth quarter of 2015.

5. Results of Operations

5.1 Upstream

Total Upstream net earnings include results from both the Exploration and Production and Infrastructure and Marketing operations. Net earnings on a combined basis reflect weaker Exploration and Production earnings compared to the same period in 2014 primarily due to lower realized crude oil prices and North American natural gas prices resulting from declining market benchmarks. The decrease was partially offset by higher production, a weaker Canadian dollar and higher realized contracted prices on production from the Liwan Gas Project in the Asia Pacific Region.

Exploration and Production

Exploration and Production Earnings Summary	Three months ended March 31,	
($ millions)	**2015**	2014
Gross revenues	**1,355**	2,182
Royalties	**(130)**	(290)
Net revenues	**1,225**	1,892
Purchases, operating, transportation and administrative expenses	**590**	646
Depletion, depreciation and amortization	**719**	573
Exploration and evaluation expenses	**57**	40
Other expenses	**20**	126
Income tax expense (recovery)	**(42)**	131
Net earnings (loss)	**(119)**	376

Exploration and Production net earnings decreased by $495 million in the first quarter of 2015 compared to the first quarter of 2014 primarily due to lower realized crude oil and North American natural gas prices resulting from significant declines in market benchmarks and higher depletion, depreciation and amortization expense attributable to a higher depletion rate on production from the Liwan Gas Project. The decreases were partially offset by higher NGL and natural gas production, higher realized contract prices on production from the Liwan Gas Project, lower royalties and a weaker Canadian dollar.

Production increased by 30.1 mboe/day to 356.0 mboe/day in the first quarter of 2015 compared to 325.9 mboe/day in the first quarter of 2014. The increase was primarily due to higher NGL and natural gas production from the Liwan Gas Project which commenced late in the first quarter of 2014, increased production from the Ansell liquids-rich natural gas resource play and strong production from the Company's heavy oil thermal developments. The increases were partially offset by natural reservoir declines at mature properties in Western Canada and the Atlantic Region.

The average realized price for crude oil, NGL and bitumen in the first quarter of 2015 was $43.43/bbl compared to $87.32/bbl during the same period in 2014, a 50 percent decrease, due to lower crude oil benchmark prices partially offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. The price realized for natural gas averaged $5.96/mcf in the first quarter of 2015 compared to $4.82/mcf in the same period in 2014, an increase of 24 percent, primarily due to higher realized contract prices on production from the Liwan Gas Project partially offset by lower natural gas benchmark prices in North America.

	Three months ended March 31,	
Average Sales Prices Realized	**2015**	2014
Crude oil and NGL *($/bbl)*		
Light crude oil & NGL	**58.05**	110.48
Medium crude oil	**39.10**	83.47
Heavy crude oil	**32.97**	72.18
Bitumen	**34.97**	70.78
Total crude oil and NGL average	**43.43**	87.32
Natural gas average *($/mcf)*	**5.96**	4.82
Total average *($/boe)*	**40.84**	72.21

The price realized for Western Canada crude oil in the first quarter of 2015 reflected lower WTI prices partially offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. The premium to WTI realized for offshore production reflects Brent prices. Realized natural gas prices reflect favourable prices received at the Liwan Gas Project partially offset by lower natural gas benchmark prices in North America.

Daily Gross Production	Three months ended March 31, 2015	2014
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**29.8**	31.4
Medium crude oil	**18.7**	23.7
Heavy crude oil	**71.9**	75.5
Bitumen[(1)]	**55.7**	52.0
	176.1	182.6
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**33.6**	43.7
Terra Nova – light crude oil	**8.1**	6.6
	41.7	50.3
Asia Pacific Region		
Light crude oil & NGL[(2)]	**18.7**	8.7
	236.5	241.6
Natural gas *(mmcf/day)*		
Western Canada	**524.2**	505.9
Asia Pacific Region[(2)]	**192.8**	—
	717.0	505.9
Total *(mboe/day)*	**356.0**	325.9

(1) Bitumen production includes heavy oil thermal average daily gross production of 45.5 mbbls/day for the three months ended March 31, 2015 compared to 41.1 mbbls/day for the three months ended March 31, 2014.

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

Crude Oil and NGL Production

Crude oil and NGL production in the first quarter of 2015 decreased by 5.1 mbbls/day or two percent compared to the same period in 2014 primarily due to natural reservoir declines at mature properties in Western Canada and the Atlantic Region partially offset by higher NGL production from the Liwan Gas Project and strong production from the Company's heavy oil thermal developments.

Natural Gas Production

Natural gas production in the first quarter of 2015 increased by 211.1 mmcf/day or 42 percent compared to the first quarter of 2014 primarily due to higher production from the Liwan Gas Project and increased production at the Ansell liquids-rich natural gas resource play.

2015 Production Guidance

The following table shows actual daily production for the three months ended March 31, 2015 and the year ended December 31, 2014, as well as the previously issued production guidance for 2015:

		Actual Production	
	2015 Guidance	**Three months ended March 31, 2015**	Year ended December 31, 2014
Canada			
Light / Medium crude oil & NGL *(mbbls/day)*	87 - 92	**90**	96
Heavy crude oil & bitumen *(mbbls/day)*	125 - 135	**128**	131
Natural gas *(mmcf/day)*	440 - 480	**524**	507
Canada total *(mboe/day)*	285 - 307	**305**	312
Asia Pacific			
Light crude oil & NGL *(mbbls/day)*	13 - 15	**19**	9
Natural gas *(mmcf/day)*	160 - 195	**193**	114
Asia Pacific total *(mboe/day)*	40 - 48	**51**	28
Total *(mboe/day)*	325 - 355	**356**	340

Royalties

In the first quarter of 2015, royalty rates as a percentage of gross revenues averaged 10 percent compared to 14 percent in the same period in 2014. Royalty rates in Western Canada averaged 11 percent in both the first quarter of 2015 and 2014. Royalty rates for the Atlantic Region averaged 14 percent in the first quarter of 2015 compared to 19 percent in the same period in 2014 due to higher eligible royalty costs for the White Rose Expansion project in 2015. Royalty rates in the Asia Pacific Region averaged five percent in the first quarter of 2015 compared to 24 percent in the same period in 2014 due to lower royalty rates associated with production from the Liwan Gas Project which started producing at the end of the first quarter of 2014.

Operating Costs

	Three months ended March 31,	
($ millions)	**2015**	2014
Western Canada	**426**	470
Atlantic Region	**50**	57
Asia Pacific	**21**	8
Total	**497**	535
Unit operating costs *($/boe)*	**14.87**	17.21

Total Exploration and Production operating costs in the first quarter of 2015 were $497 million compared to $535 million in the same period in 2014. Total unit operating costs in the first quarter of 2015 averaged $14.87/boe compared to $17.21/boe in the same period in 2014.

Operating costs in Western Canada averaged $17.12/boe in the first quarter of 2015 compared to $18.26/boe in the same period in 2014. The decrease in operating costs was primarily attributable to lower energy input costs in the first quarter of 2015 compared to the same period in 2014.

Operating costs in the Atlantic Region averaged $13.36/boe in the first quarter of 2015 compared to $12.59/boe in the same period in 2014. The increase in operating costs on a per barrel basis was primarily attributable to lower production volumes partially offset by lower research and development, fuel, vessel and logistics costs when compared to the same period in 2014.

Operating costs in the Asia Pacific Region averaged $4.51/boe in the first quarter of 2015 compared to $10.56/boe in the same period in 2014. The decrease was primarily due to lower unit cost production from the Liwan Gas Project which commenced at the end of the first quarter of 2014.

Exploration and Evaluation Expenses

	Three months ended March 31,	
($ millions)	**2015**	2014
Seismic, geological and geophysical	**21**	25
Expensed drilling	**32**	12
Expensed land	**4**	3
Exploration and evaluation expenses	**57**	40

Exploration and evaluation expenses in the first quarter of 2015 were $57 million compared to $40 million in the first quarter of 2014. The increase in expensed drilling costs was primarily for the Aster exploration well in the Atlantic Region as the well did not encounter economic quantities of hydrocarbons. The decrease in seismic, geological and geophysical costs resulted from lower seismic activity across the portfolio.

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

During the first quarter of 2015, total DD&A averaged $22.45/boe compared to $19.55/boe in the first quarter of 2014. The increase was primarily attributable to higher depletion rates per boe on production from the Liwan Gas Project.

Exploration and Production Capital Expenditures

During the first quarter of 2015, Upstream Exploration and Production capital expenditures were $724 million. Capital expenditures were $395 million (54%) in Western Canada including Heavy Oil, $120 million (17%) in Oil Sands, $187 million (26%) in the Atlantic Region and $22 million (3%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1]	Three months ended March 31,	
($ millions)	**2015**	2014
Exploration		
Western Canada	**12**	54
Oil Sands	**—**	25
Atlantic Region	**60**	7
Asia Pacific Region	**1**	9
	73	95
Development		
Western Canada	**382**	591
Oil Sands	**120**	133
Atlantic Region	**127**	154
Asia Pacific Region	**21**	149
	650	1,027
Acquisitions		
Western Canada	**1**	2
	724	1,124

(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[1]		**2015**		2014
(wells)	**Gross**	**Net**	Gross	Net
Exploration				
Oil	**5**	**4**	44	43
Gas	**2**	**—**	2	2
Dry	**—**	**—**	—	—
	7	**4**	46	45
Development				
Oil	**43**	**37**	203	187
Gas	**14**	**10**	13	11
Dry	**—**	**—**	—	—
	57	**47**	216	198
Total	**64**	**51**	262	243

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

The Company drilled 51 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first quarter of 2015 resulting in 41 net oil wells and 10 net natural gas wells compared to 243 net wells resulting in 230 net oil wells and 13 net natural gas wells in the first quarter of 2014.

During the first quarter of 2015, Husky invested $395 million in exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $647 million in the same period in 2014 as activity has been curtailed in the current low commodity price environment. Property acquisitions totalling $1 million were completed in the first quarter of 2015 compared to $2 million in the same period in 2014. Investment in oil related exploration and development in the first quarter of 2015 was $23 million compared to $148 million in the first quarter of 2014. Investment in natural gas related exploration and development, primarily liquids-rich, was $96 million in the first quarter of 2015 compared to $174 million in the first quarter of 2014.

In addition, $26 million was spent on production optimization and cost reduction initiatives in the first quarter of 2015 compared to $56 million in the same period in 2014. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $177 million in the first quarter of 2015 compared to $101 million in the same period in 2014.

Capital expenditures on heavy oil thermal developments and horizontal drilling were $72 million in the first quarter of 2015 compared to $166 million in the same period in 2014.

Oil Sands

During the first quarter of 2015, $120 million was invested in Oil Sands projects, compared to $158 million in the same period in 2014, primarily on the development of Phase 1 of the Sunrise Energy Project.

Atlantic Region

During the first quarter of 2015, $187 million was invested in Atlantic Region projects, compared to $161 million in the same period in 2014, 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 2015, $22 million was invested in Asia Pacific Region projects, compared to $158 million in the same period in 2014. Development of the Liwan Gas Project was substantially completed in 2014.

Upstream Planned Turnarounds

- A planned turnaround at the Ansell liquids-rich gas resource play in Western Canada is expected to have an impact of about 1,700 boe/day in the second quarter of 2015. A planned turnaround at the Ram River plant has been deferred until 2016.
- Other scheduled third-party shutdowns are expected to impact Western Canada production by approximately 3,300 boe/day in the third quarter of 2015.
- A three-week maintenance shutdown is planned at the Tucker heavy oil thermal project and is expected to have an impact of approximately 2,400 bbls/day in the second quarter of 2015.
- Partial shut-downs are scheduled at several heavy oil thermal projects to perform routine maintenance, with an estimated aggregate impact of 8,000 bbls/day in June 2015.
- A planned ten-week maintenance turnaround for the Terra Nova FPSO is expected to impact production by approximately 5,100 bbls/day in the second quarter of 2015.
- An 18-day turnaround on the SeaRose FPSO vessel is expected to impact production by approximately 7,500 bbls/day in the third quarter of 2015.

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)	**2015**	2014
Infrastructure gross margin	**31**	44
Marketing and other gross margin	**69**	34
Gross margin	**100**	78
Operating and administrative expenses	**11**	10
Depreciation and amortization	**5**	7
Other income	**(1)**	—
Income tax expense	**22**	15
Net earnings	**63**	46
Commodity trading volumes managed *(mboe/day)*	**292.7**	282.5

Infrastructure and Marketing net earnings in the first quarter of 2015 increased by $17 million compared to the same period in 2014 as the rising forward price curve resulted in significant unrealized mark to market gains partially offset by the narrowing of product and location differentials between Canada and the United States. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the United States market.

Infrastructure and Marketing Capital Expenditures

In the first quarter of 2015, Infrastructure and Marketing capital expenditures totalled $19 million compared to $24 million in the same period in 2014. Capital expenditures in the first quarter of 2015 related primarily to the expansion of the Saskatchewan Gathering System into Lloydminster.

5.2 Downstream

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing. The decrease in Upgrader net earnings was primarily due to the impact of significantly lower upgrading differentials. The decrease in Canadian Refined Products net earnings was primarily due to lower realized sales prices from the Prince George and Lloydminster Refineries partially offset by lower heavy crude oil feedstock costs. The increase in U.S. Refining and Marketing net earnings was primarily due to a deferred income tax recovery of $203 million related to the partial payment of the contribution payable to BP-Husky Refining LLC partially offset by unplanned refinery outages at both the Lima and BP-Husky Toledo Refineries and by the impact of falling crude oil prices at the beginning of the quarter resulting in FIFO losses in realized refining margins.

Upgrader

Upgrader Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2015**	2014
Gross revenues	**347**	573
Gross margin	**109**	189
Operating and administrative expenses	**44**	49
Depreciation and amortization	**26**	24
Other expenses (income)	**(11)**	9
Income tax expense	**13**	28
Net earnings	**37**	79
Upgrader throughput *(mbbls/day)*[(1)]	**83.7**	72.4
Total sales *(mbbls/day)*[(2)]	**81.0**	71.1
Synthetic crude oil sales *(mbbls/day)*	**58.5**	53.9
Upgrading differential *($/bbl)*	**15.72**	27.40
Unit margin *($/bbl)*[(2)]	**14.95**	29.54
Unit operating cost *($/bbl)*[(3)]	**5.71**	7.21

(1) *Throughput includes diluent returned to the field.*
(2) *Unit margin was revised in the first quarter of 2015 to reflect total sales volumes. Prior periods have been adjusted to conform with current period presentation.*
(3) *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 2015 were $37 million compared to $79 million in the same period in 2014. The decrease was primarily due to lower average upgrading differentials partially offset by higher throughput and sales volumes. Other income increased by $20 million in the first quarter of 2015 resulting primarily from the revaluation of the final contingent consideration payment made to Natural Resources Canada and the Alberta Department of Energy.

During the first quarter of 2015, the upgrading differential averaged $15.72/bbl, a decrease of $11.68/bbl or 43 percent compared to the same period in 2014. 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 only partially offset by lower heavy oil feedstock costs compared to the same period of 2014. The average price for Husky Synthetic Blend in the first quarter of 2015 was $55.51/bbl compared to $106.26/bbl in the same period in 2014. The overall unit margin was $14.95/bbl in the first quarter of 2015 compared to $29.54/bbl in the same period in 2014.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2015**	2014
Gross revenues	**601**	939
Gross margin		
Fuel	**33**	32
Refining	**28**	81
Asphalt	**44**	61
Ancillary	**13**	14
	118	188
Operating and administrative expenses	**73**	73
Depreciation and amortization	**25**	24
Other expenses	**2**	—
Income tax expense	**5**	23
Net earnings	**13**	68
Number of fuel outlets[(1)]	**488**	503
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.6**	7.7
Fuel sales per retail outlet *(thousands of litres/day)*	**12.4**	13.4
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**11.4**	12.0
Lloydminster Refinery *(mbbls/day)*	**29.2**	29.0
Ethanol production *(thousands of litres/day)*	**775.5**	789.3

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

Asphalt gross margins were lower in the first quarter of 2015 compared to the same period in 2014 primarily due to reduced drilling activity in Western Canada resulting in lower demand and sales prices for drilling fluids, partially offset by lower heavy crude oil feedstock costs.

Refining gross margins were lower in the first quarter of 2015 compared to the same period in 2014 primarily due to lower realized product pricing and lower throughput at the Prince George Refinery.

Fuel gross margins were comparable in the first quarter of 2015 and 2014 as higher fuel margins were partially offset by lower sales volumes resulting from select retail outlet closures.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2015**	2014
Gross revenues	**1,725**	2,420
Gross refining margin	**186**	364
Operating and administrative expenses	**131**	124
Depreciation and amortization	**69**	61
Other expenses	**1**	1
Income tax expense (recovery)	**(209)**	66
Net earnings	**194**	112
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**119.2**	110.5
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**52.1**	65.5
Refining margin *(U.S. $/bbl crude throughput)*	**10.04**	21.63
Refinery inventory *(mmbbls)*(1)	**10.7**	9.9

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

U.S. Refining and Marketing net earnings include a recovery of deferred income tax of $203 million related to the partial payment of the contribution payable to BP-Husky Refining LLC.

Net earnings on an operational basis excluding the income tax recovery decreased in the first quarter of 2015 compared to the same period in 2014 primarily due to unplanned outages at both the Lima and BP-Husky Toledo Refineries, the impact of falling crude oil prices at the beginning of the quarter resulting in FIFO losses in realized refining margins combined with lower market crack spreads. In addition, the Company purchased refined products from third parties to deliver on committed sales volumes during the unplanned outage at Lima which also impacted the realized refining margin in the first quarter of 2015.

Throughput volumes and operating expenses in the first quarter of 2015 were negatively impacted at the Lima Refinery by an unplanned outage when a fire occurred in the isocracker unit in January and at the BP-Husky Toledo Refinery by an unplanned maintenance outage to repair a damaged fluid catalytic cracking unit. Repairs on the fluid catalytic cracking unit at the BP-Husky Toledo Refinery were completed in the second quarter of 2015. Work resumption plans are underway on the isocracker unit at the Lima Refinery and the unit is expected to start up in early 2016.

The Company carries business interruption and property damage insurance in relation to the isocracker unit. Insurance recoveries expected to offset losses incurred are not reflected in results from the first quarter of 2015.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out accounting ("LIFO"), 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. The estimated FIFO impact was a decrease in net earnings of approximately $9 million in the first quarter of 2015 compared to an increase in net earnings of approximately $63 million in the same period in 2014. 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 2015, Downstream capital expenditures totalled $61 million compared to $90 million in the same period in 2014. In Canada, capital expenditures of $13 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. At the Lima Refinery, $36 million was spent primarily on various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $12 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

5.3 Corporate

Corporate Summary	Three months ended March 31,	
($ millions) income (expense)	**2015**	2014
Administrative expenses	**(30)**	(18)
Stock-based compensation	**10**	(6)
Depreciation and amortization	**(20)**	(16)
Foreign exchange gain	**62**	18
Interest income (expense)	**(13)**	7
Income tax expense	**(6)**	(4)
Net income (loss)	**3**	(19)

The Corporate segment reported net income of $3 million in the first quarter of 2015 compared to a net loss of $19 million in the same period in 2014. Administrative expenses increased by $12 million compared to the same period in 2014 primarily due to a reclassification of early invoice payment discounts to the Company's Upstream and Downstream segments. Stock-based compensation expense decreased by $16 million in the first quarter of 2015 compared to the same period in 2014 as a result of a decrease in the Company's share price resulting in a recovery. Foreign exchange was a gain of $62 million compared to $18 million in the same period in 2014 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. Interest expense increased by $20 million due to higher debt and a decrease in the amount of capitalized interest related to production being achieved at the Liwan Gas Project late in the first quarter of 2014 and production being achieved at the Sunrise Energy Project in the first quarter of 2015.

Foreign Exchange Summary	Three months ended March 31,	
($ millions, except where indicated)	**2015**	2014
Losses on translation of U.S. dollar denominated long-term debt	**(27)**	—
Gains on contribution receivable	**—**	7
Gains on non-cash working capital	**55**	16
Other foreign exchange gains (losses)	**34**	(5)
Net foreign exchange gains	**62**	18
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $0.862**	U.S. $0.940
At end of period	**U.S. $0.788**	U.S. $0.905

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.

Corporate Capital Expenditures

In the first quarter of 2015, Corporate capital expenditures were $17 million compared to $31 million in the same period in 2014. Capital expenditures for both periods are primarily related to computer hardware and software and leasehold improvements.

Consolidated Income Taxes

Consolidated income taxes in the first quarter of 2015 were a recovery of $205 million compared with an expense of $267 million in the same period in 2014 primarily due to a future income tax recovery from the distribution of U.S. $1.0 billion by BP-Husky Refining LLC to each member following the partial payment of the contribution payable by the Company.

	Three months ended March 31,	
($ millions)	**2015**	2014
Income tax expense (recovery)	**(205)**	267
Cash taxes paid (recovered)	**(4)**	96

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the first quarter of 2015, Husky funded its capital programs and dividend payments through cash generated from operating activities, cash on hand, the issuance of commercial paper, the issuance of preferred shares and the issuance of long-term debt. At March 31, 2015, Husky had total debt of $5,997 million partially offset by cash on hand of $169 million for $5,828 million of net debt compared to $4,025 million of net debt at December 31, 2014. At March 31, 2015, the Company had $3,624 million of unused credit facilities of which $3,185 million was long-term committed credit facilities and $439 million was short-term uncommitted credit facilities. In addition, the Company had $2.05 billion in unused capacity under its February 2015 Canadian universal short form base shelf prospectus (the "2015 Canadian Shelf Prospectus") and U.S. $2.25 billion in unused capacity under its October 2013 U.S. universal short form base shelf prospectus (the "U.S. 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)	**2015**	2014
Cash flow		
Operating activities	**864**	1,336
Financing activities	**242**	655
Investing activities	**(2,302)**	(1,573)

Cash Flow from Operating Activities

In the first quarter of 2015, cash flow generated from operating activities was $864 million compared to $1,336 million in the same period in 2014. The decrease was primarily due to lower realized crude oil and North American natural gas prices and lower refining margins in U.S. Refining and Marketing. The decreases were partially offset by higher production, a weaker Canadian dollar and a decrease in investment non-cash working capital.

Cash Flow from Financing Activities

In the first quarter of 2015, cash flow generated from financing activities was $242 million compared to $655 million in the same period in 2014. The decrease was primarily due to the repayment of $300 million medium-term notes and the repayment of $390 million in commercial paper during the first quarter of 2015, partially offset by the draw-down of $310 million from the Company's syndicated credit facilities and proceeds from the issuance of $200 million of Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares"). Refer to Section 6.2.

Cash Flow used for Investing Activities

In the first quarter of 2015, cash used for investing activities was $2.3 billion compared to $1.6 billion in the same period in 2014. The increase was primarily due to the payment of $1.3 billion of the Company's BP-Husky Refining LLC contribution payable. The increase in cash used for investing activities was partially offset by a reduction in capital expenditures.

6.2 Sources of Capital

Husky funds its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, cash on hand, the issuance of long-term debt, borrowings under committed and uncommitted credit facilities, the issuance of short-term commercial paper and the issuance of equity. The Company also maintains access to sufficient capital via debt and equity 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. At March 31, 2015, the Company's debt to capital employed was 22.2 percent (December 31, 2014 - 19.8 percent). Debt to capital employed constitutes a non-GAAP measure. Refer to Section 11.

Working capital is the amount by which current assets exceed current liabilities. At March 31, 2015, working capital deficiency was $112 million compared to a working capital deficiency of $1,314 million at December 31, 2014. The decrease in working capital deficiency was mainly attributable to the payment of $1.3 billion of the Company's BP-Husky Refining LLC contribution payable. A portion of the payment was financed from proceeds received from the issuance of $750 million of long-term debt and from proceeds received from the issuance of $200 million of the Series 5 Preferred Shares in the first quarter of 2015.

At March 31, 2015, Husky had unused short and long-term credit facilities totalling $3.6 billion. A total of $206 million of the Company's short-term credit facilities was used in support of outstanding letters of credit and $505 million of the Company's long-term borrowing credit facilities was used in support of commercial paper.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at March 31, 2015.

On October 31, 2013 and November 1, 2013, Husky filed 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. At March 31, 2015, the Company had unused capacity of $2.25 billion under its U.S. Shelf Prospectus.

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.

On February 23, 2015, the Company filed the 2015 Canadian Shelf Prospectus with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including March 22, 2017. At March 31, 2015, the Company had unused capacity of $2.05 billion under its 2015 Canadian Shelf Prospectus.

On March 6, 2015, the Company's $1.63 billion and the $1.60 billion revolving syndicated credit facilities were each increased to $2.0 billion. The terms of the revolving syndicated credit facilities remain unchanged.

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

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

The ability of the Company to raise capital utilizing the 2015 Canadian Shelf Prospectus or the U.S. Shelf Prospectus is dependent on market conditions at the time of sale.

Capital Structure		**March 31, 2015**
($ millions)	**Outstanding**	**Available[(1)]**
Total debt	5,997	3,624
Common shares, preferred shares, retained earnings and other reserves	20,960	

[(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 2014 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2014.

On March 12, 2015, the Company issued $750 million of 3.55 percent notes due March 12, 2025 by way of a prospectus supplement dated March 9, 2015, to the 2015 Canadian Shelf Prospectus which was the only material change to its 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

The Company sells natural gas to and purchases steam from the Meridian cogeneration facility ("Meridian"). 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, 2015, the amount of natural gas sales to Meridian, owned by the related party, totalled $14 million. For the three months ended March 31, 2015, the amount of steam purchased by the Company from Meridian totalled $5 million. In addition, the Company provides facility services to Meridian which are measured and reimbursed at cost. For the three months ended March 31, 2015, 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 2014 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, 2014, as discussed in Husky's 2014 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, 2015, 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 2014, the Company discontinued its cash flow hedge with respect to forward starting interest rate swaps. 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 was originally designated. The amortization period is ten years. At March 31, 2015, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $22 million (December 31, 2014 – $23 million), net of tax of $8 million (December 31, 2014 - net of tax of $8 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, 2015.

Refer to Note 12 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At March 31, 2015, 74 percent or $4.0 billion of Husky's outstanding long-term debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, six percent of the Company's long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At March 31, 2015, the Company had designated U.S. $2.9 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, 2015, the Company incurred an unrealized loss of $277 million arising from the translation of the debt, net of tax of $41 million, which was recorded in other comprehensive income ("OCI").

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, 2015, Husky's share of this obligation was U.S. $301 million including accrued interest. At March 31, 2015, the cost of a Canadian dollar in U.S. currency was $0.788.

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, 2015**	December 31, 2014
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**(6)**	(5)
Crude oil[(2)]	**44**	4
Foreign currency contracts – FVTPL		
Foreign currency forwards	**1**	(1)
Other assets – FVTPL	**2**	2
Contingent consideration	**—**	(40)
Hedging instruments[(3)]		
Hedge of net investment[(4)]	**(630)**	(353)
	(589)	(393)

(1) Natural gas contracts includes a $6 million decrease at March 31, 2015 (December 31, 2014 – $12 million decrease) 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 $59 million at March 31, 2015.

(2) Crude oil contracts includes a $32 million increase at March 31, 2015 (December 31, 2014 – $21 million decrease) 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 $303 million at March 31, 2015.

(3) Hedging instruments are presented net of tax.

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

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 2014 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

IFRS 8 Operating Segments

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

IFRS 2 Share-based Payment

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

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

The adoption of this amended standard has no impact on the Company's Consolidated Financial Statements.

IFRS 3 Business Combinations

The amendment is applied prospectively and clarifies that all contingent consideration arrangements classified as liabilities (or assets) arising from a business combination should be subsequently measured at fair value through profit or loss whether or not they fall within the scope of IFRS 9 (or International Accounting Standard ("IAS") 39, as applicable). The adoption of this amended standard has 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, 2015	
• common shares	983,964,405
• cumulative redeemable preferred shares, series 1	12,000,000
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• stock options	30,898,072
• stock options exercisable	19,346,532

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 2014 Annual MD&A, the 2014 Consolidated Financial Statements and the 2014 Annual Information Form filed with Canadian securities regulatory authorities and the 2014 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, 2015 are compared to the results for the three months ended March 31, 2014. Discussions with respect to Husky's financial position at March 31, 2015 are compared to its financial position at December 31, 2014. 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 IAS 34, "Interim Financial Reporting" as issued by the International Accounting Standards Board.
- 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, 2015 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: adjusted net earnings, cash flow from operations, operating netback, debt to capital employed and LIFO. None of these measurements are used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for operating netback or debt to capital employed. 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. All non-GAAP measures are defined below.

Disclosure of Adjusted Net Earnings

The term "Adjusted Net Earnings" is a non-GAAP measure comprised of net earnings excluding extraordinary and non-recurring items such as after-tax property, plant and equipment impairment charges and after-tax inventory write-downs not considered to be 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 for the three months ended March 31, 2015 and 2014:

		Three months ended March 31,	
($ millions)		2015	2014
GAAP	Net earnings	191	662
	Inventory write-downs, net of tax	—	7
Non-GAAP	Adjusted net earnings	191	669

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 net earnings to cash flow from operations and related per share amounts for the three months ended March 31, 2015 and 2014:

		Three months ended March 31,	
($ millions)		**2015**	2014
GAAP	Net earnings	**191**	662
	Items not affecting cash:		
	Accretion	**30**	34
	Depletion, depreciation and amortization	**864**	705
	Exploration and evaluation expenses	**—**	2
	Deferred income tax expenses (recoveries)	**(259)**	6
	Foreign exchange	**28**	13
	Stock-based compensation	**(10)**	6
	Loss (gain) on sale of assets	**8**	(1)
	Other	**(14)**	109
Non-GAAP	Cash flow from operations	**838**	1,536
	Cash flow from operations – basic	**0.85**	1.56
	Cash flow from operations – diluted	**0.85**	1.56

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. Management believes 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.

Debt to Capital Employed

Debt to capital employed percentage is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year and commercial paper divided by capital employed. Capital employed is equal to long-term debt, long-term debt due within one year, commercial paper and shareholders' equity. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

LIFO

The Chicago 3:2:1 market crack spread benchmark is based on LIFO inventory costing, a non-GAAP measure, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis, the comparable GAAP measure, crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter. Management believes that comparisons between LIFO and FIFO inventory costing assist management and investors in assessing differences in the Company's realized refining margins compared to the Chicago 3:2:1 market crack spread benchmark.

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 before after-tax property, plant and equipment impairment charges and after-tax inventory 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, long-term debt due within one year, commercial paper and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gain or loss on sale of property, plant, and equipment and other non-cash items*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and commercial paper divided by capital employed*
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*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
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	*Common shares, preferred 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*
bbls/day	*barrels per day*
boe	*barrels of oil equivalent*
boe/day	*barrels of oil equivalent per day*
CHOPS	*cold heavy oil production with sand*
CPF	*Central Processing Facility*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A.)*
FEED	*Front-end engineering design*
FIFO	*first in first out*
FPSO	*Floating production, storage and offloading vessel*
FVTPL	*fair value through profit or loss*
GAAP	*Generally Accepted Accounting Principles*
GJ	*gigajoule*
IAS	*International Accounting Standard*
ICFR	*Internal Controls over Financial Reporting*
IFRIC	*International Financial Reporting Interpretations Committee*
IFRS	*International Financial Reporting Standards*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mcf	*thousand cubic feet*
MD&A	*Management's Discussion and Analysis*
mmbbls	*million barrels*
mmboe	*million barrels of oil equivalent*
mmbtu	*million British Thermal Units*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
NGL	*natural gas liquids*
NYMEX	*New York Mercantile Exchange*
OCI	*other comprehensive income*
SEDAR	*System for Electronic Document Analysis and Retrieval*
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; anticipated production guidance range for the year; expected timing, duration and impact of planned turnarounds and maintenance shutdowns at the Company's projects;
- with respect to the Company's Atlantic Region: anticipated timing of first production from the Company's South White Rose Extension project; scheduled timing of recommencement of drilling at, and commencement of production from, the Hibernia formation well at the North Amethyst field;
- with respect to the Company's Oil Sands properties: anticipated timing of ramp-up to, and volumes, of peak daily production from the Company's Sunrise Energy Project; planned timing of production sales from the Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: anticipated timing of first production from, forecast net peak daily production from, the Company's Rush Lake, Edam East, Edam West and Vawn heavy oil thermal projects, and expected sustaining capital requirements of the Company's heavy oil thermal developments;
- with respect to the Company's Western Canadian oil and gas resource plays: drilling and completions plans for 2015;
- with respect to the Company's Infrastructure and Marketing segment: anticipated outcome of expansion of the Saskatchewan Gathering System; and
- with respect to the Company's Downstream business segment: planned timing of engineering and construction of the crude oil flexibility project at the Lima, Ohio Refinery; expected timing of completion of construction to address regulatory monitoring and emission standards at the BP-Husky Toledo Refinery; expected timing of start-up of the isocracker unit at the Lima, Ohio 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, 2014 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe 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.