MANAGEMENT'S DISCUSSION AND ANALYSIS

April 25, 2016

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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)	**2016**	2015	2015	2015	2015	2014	2014	2014
Production *(mboe/day)*	**341.3**	357.0	333.0	336.9	356.0	359.6	341.1	333.6
Gross revenues and marketing and other	**2,578**	3,903	4,286	4,526	4,086	5,875	6,690	6,614
Net earnings (loss)	**(458)**	(69)	(4,092)	120	191	(603)	571	628
Per share – Basic	**(0.47)**	(0.08)	(4.17)	0.11	0.19	(0.62)	0.58	0.63
Per share – Diluted	**(0.47)**	(0.09)	(4.19)	0.10	0.17	(0.65)	0.52	0.63
Adjusted net earnings (loss)[(1)]	**(458)**	(49)	(101)	124	191	148	572	629
Cash flow from operations[(1)]	**434**	640	674	1,177	838	1,145	1,341	1,504
Per share – Basic	**0.43**	0.65	0.68	1.20	0.85	1.16	1.36	1.53
Per share – Diluted	**0.43**	0.65	0.68	1.20	0.85	1.16	1.36	1.52

(1) *Adjusted net earnings (loss) and cash flow from operations are non-GAAP measures. Refer to Section 11 for a reconciliation to the GAAP measures.*

Performance

- Net loss of $458 million in the first quarter of 2016 compared to net earnings of $191 million in the first quarter of 2015 with the decrease primarily due to:
  - A deferred income tax recovery of $203 million recorded in the first quarter of 2015 following the partial payment of the contribution payable to BP-Husky Refining LLC;
  - Lower realized crude oil and North American natural gas prices;
  - Lower natural gas and natural gas liquids ("NGLs") production from the Asia Pacific Region;
  - Unrealized mark to market losses on forward commodity contracts; and
  - Lower realized U.S. Refining and Marketing margins;
  - Partially offset by lower royalties, operating costs and depletion, depreciation and amortization ("DD&A"); and
  - A weaker Canadian dollar.
- Cash flow from operations of $434 million in the first quarter of 2016 compared to $838 million in the first quarter of 2015 with the decrease primarily due to lower realized crude oil and North American natural gas prices partially offset by a weaker Canadian dollar and lower royalties and operating costs.
- Production decreased by 14.7 mboe/day or four percent to 341.3 mboe/day in the first quarter of 2016 compared to the first quarter of 2015 as a result of:
  - Lower natural gas and NGLs production from the Liwan Gas Project in the Asia Pacific Region; and
  - Natural reservoir declines at mature crude oil properties in Western Canada and the Atlantic Region with limited sustaining capital investment in a low commodity price environment;
  - Partially offset by new production from the Rush Lake heavy oil thermal development, the Sunrise Energy Project and the South White Rose extension.

Key Projects

- Gross production from the Sunrise Energy Project continued to ramp-up, averaging 18,600 bbls/day (9,300 bbls/day net Husky share) in the first quarter of 2016, and reached 28,200 bbls/day (14,100 bbls/day net Husky share) as at March 31, 2016. Production from the Sunrise Energy Project is expected to increase to 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016.
- First oil was achieved at the 10,000 bbls/day Edam East heavy oil thermal development on April 18, 2016.
- Construction continued at the 10,000 bbls/day Vawn and the 4,500 bbls/day Edam West heavy oil thermal developments where first production is expected in the third quarter of 2016.
- Development of the Colony formation at the Tucker thermal project in the Cold Lake region commenced in 2015 and achieved first production on April 19, 2016. This formation has similar characteristics to heavy oil thermal reservoirs in the Lloydminster region. Total production from Tucker is expected to reach approximately 20,000 bbls/day in the second half of 2016.
- In the Atlantic Region, the Company has secured the Henry Goodrich drilling rig for a two-year drilling program. The rig will be utilized for further development drilling at the South White Rose extension and the completion of North Amethyst's Hibernia formation production well.
- In Indonesia, progress continued on the BD, MDA, MBH and MDK shallow water gas developments in the Madura Strait Block. At the liquids-rich BD field, wellhead platform and pipeline infrastructure construction is approximately 70 percent complete and construction of a floating production, storage and offloading ("FPSO") vessel is approximately 65 percent complete. Development well drilling is underway and production is expected from the BD field in the 2017 timeframe. Production from the MDA, MBH and MDK fields is expected in the 2018 - 2019 timeframe. Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be approximately 100 mmcf/day of gas and 2,400 boe/day of associated NGLs once fully ramped up.
- Construction is approximately 80 percent complete for the expansion of the Saskatchewan Gathering System which will accommodate production from the Company's heavy oil thermal developments. Production from the Rush Lake thermal development is flowing in a completed section of the expanded pipeline system into Lloydminster.
- During 2015, Husky and Imperial Oil entered into a contractual agreement to create a single expanded truck transport network of approximately 160 sites. The agreement is subject to regulatory approval by Canada's Competition Bureau and other closing conditions.
- The Company is proceeding with the initial stages of a crude oil flexibility project at the Lima Refinery designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The crude oil flexibility project will allow the Refinery to swing between light and heavy crude oil feedstock. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.
- During 2015, a feedstock optimization project was sanctioned at the BP-Husky Refinery by the joint arrangement partners which is designed to improve the Refinery's ability to process crude oils with a high content of naphthenic acids ("Hi-TAN"). Targeted completion of the required metallurgy changes will be performed during the Refinery's turnaround starting in the second quarter of 2016. Once the upgrades are complete, the Refinery will have the ability to process up to an additional 35,000 bbls/day of Hi-TAN crude. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.

Financial

- Dividends on preferred shares of $10 million were declared and paid in the first quarter of 2016.
- On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020.

2. Business Environment

Average Benchmarks

Average Benchmarks Summary		Three months ended Mar. 31, 2016	Dec. 31, 2015	Sept. 30, 2015	Jun. 30, 2015	Mar. 31, 2015
West Texas Intermediate ("WTI") crude oil[(1)]	*(U.S. $/bbl)*	**33.45**	42.18	46.43	57.94	48.63
Brent crude oil[(2)]	*(U.S. $/bbl)*	**33.89**	43.69	50.26	61.92	53.97
Light sweet at Edmonton	*($/bbl)*	**40.81**	52.95	56.23	67.72	51.93
Daqing[(3)]	*(U.S. $/bbl)*	**30.15**	39.57	46.04	60.01	51.41
Western Canadian Select at Hardisty[(4)]	*(U.S. $/bbl)*	**19.21**	27.69	33.16	46.35	33.90
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**18.49**	30.23	38.66	51.31	36.41
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**14.04**	14.37	13.24	11.49	14.63
Condensate at Edmonton	*(U.S. $/bbl)*	**34.40**	41.67	44.21	57.94	45.62
NYMEX natural gas[(5)]	*(U.S. $/mmbtu)*	**2.09**	2.27	2.77	2.64	2.98
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**2.00**	2.51	2.65	2.53	2.80
Chicago Regular Unleaded Gasoline	*(U.S. $/bbl)*	**41.88**	54.77	72.02	79.43	61.97
Chicago Ultra-low Sulphur Diesel	*(U.S. $/bbl)*	**44.81**	58.97	67.08	75.89	70.22
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**9.23**	14.00	23.87	20.30	16.14
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.728**	0.749	0.764	0.813	0.806
Canadian $ Equivalents[(6)]						
WTI crude oil	*($/bbl)*	**45.95**	56.32	60.77	71.27	60.33
Brent crude oil	*($/bbl)*	**46.55**	58.33	65.79	76.16	66.96
Daqing	*($/bbl)*	**41.41**	52.83	60.26	73.81	63.78
Western Canadian Select at Hardisty	*($/bbl)*	**26.39**	36.97	43.40	57.01	42.06
WTI/Lloyd crude blend differential	*($/bbl)*	**19.29**	19.19	17.33	14.13	18.15
NYMEX natural gas	*($/mmbtu)*	**2.87**	3.03	3.63	3.25	3.70

(1) *Calendar Month Average of settled prices for WTI at Cushing, Oklahoma.*
(2) *Calendar Month Average of settled prices for Dated Brent.*
(3) *Calendar Month Average of settled prices for Daqing.*
(4) *Western Canadian Select is a heavy blended crude oil, comprised of conventional and bitumen crude oils, blended with diluent, which terminals at Hardisty, Alberta. Quoted prices are indicative of the Index for Western Canadian Select at Hardisty, Alberta, set in the month prior of delivery.*
(5) *Prices quoted are average settlement prices during the period.*
(6) *Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.*

Crude Oil Benchmarks

Global crude oil benchmarks continued to be weak in the first quarter of 2016 resulting from the imbalance between supply and demand and the corresponding growth in global crude oil inventories.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada, the price received for crude oil production from the Atlantic Region is primarily driven by Brent and the price received for crude oil and NGLs production from the Asia Pacific Region is primarily driven by Daqing. A portion of Husky's crude oil and NGLs production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the first quarter of 2016, 60 percent of Husky's crude oil and NGLs production was heavy crude oil or bitumen compared to 54 percent in the first quarter of 2015.

Husky's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate.

Natural Gas Benchmarks

North American natural gas benchmarks continued to be weak in the first quarter of 2016 primarily due to the substantial supply of natural gas in North America resulting largely from technological advances in horizontal drilling and hydraulic fracturing which have unlocked significant reserves that were not economical under previously applied extraction methods. In addition, unseasonably mild weather conditions resulted in lower demand.

The price realized by the Company for natural gas production from Western Canada is determined primarily by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. In the Asia Pacific Region, natural gas is sold to a specific buyer with long-term contracts. For the Liwan 3-1 gas field, a price profile has been fixed for five years and then will be linked to local benchmark pricing for the years following subject to a floor and ceiling. For the Liuhua 34-2 field, the price is fixed with a single escalation step during the contract delivery period.

Natural gas is consumed internally by the Company's Upstream and Downstream operations which reduces the impact of weak North American natural gas benchmark prices on the Company's results.

Refining Benchmarks

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 calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel 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 nor the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

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 the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10 percent to 15 percent of other products that are sold at discounted market prices compared to gasoline and distillate. Husky's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards (“IFRS”).

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 whose prices are determined by reference to U.S. benchmark prices. The majority of the Company's non-hydrocarbon related expenditures are denominated 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 Asia Pacific Region operations and U.S. dollar denominated debt. The Company's earnings benefited from the weakening of the Canadian dollar in the first quarter of 2016 which averaged U.S. $0.728 compared to U.S. $0.806 in the first quarter of 2015.

The Company’s fixed long-term sales contracts in the Asia Pacific Region are priced in Chinese Yuan (“RMB”) and therefore, an increase in the value of RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of oil and gas commodities in the region. The Company's earnings benefited from the weakening of the Canadian dollar in the first quarter of 2016 which averaged RMB $4.768 compared to RMB $5.027 in the first quarter of 2015.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the first quarter of 2016 on earnings before income taxes and net earnings (loss). The table below reflects what the effect would have been on the financial results for the first quarter of 2016 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the first quarter of 2016. 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 indicative 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	2016 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)	33.45	*U.S. $1.00/bbl*	109	0.11	80	0.08
NYMEX benchmark natural gas price(5)	2.09	*U.S. $0.20/mmbtu*	21	0.02	15	0.01
WTI/Lloyd crude blend differential(6)	14.04	*U.S. $1.00/bbl*	(43)	(0.04)	(32)	(0.03)
Canadian light oil margins	0.046	*Cdn $0.005/litre*	11	0.01	8	0.01
Asphalt margins	19.85	*Cdn $1.00/bbl*	9	0.01	6	0.01
Chicago 3:2:1 crack spread	9.23	*U.S. $1.00/bbl*	40	0.04	25	0.03
Exchange rate (U.S. $ per Cdn $)(3)(7)	0.728	*U.S. $0.01*	(33)	(0.03)	(25)	(0.02)

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.5 million common shares outstanding as at March 31, 2016.*
(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 remain diverse, physically integrated and to continue its transition into a low sustaining capital business. Husky will enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward low sustaining capital 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 NGLs (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGLs, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore China and offshore Indonesia.

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading) in Canada, refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. Refining and Marketing). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and therefore, were grouped together as the Downstream business segment due to the similar nature of their products and services.

4. Key Growth Highlights

The 2016 Capital Program enables Husky to advance its near-term profitable growth projects while maintaining prudent capital management in a weak commodity price environment.

4.1 Upstream

Heavy Oil

Heavy Oil Thermal Developments

The Company continued to advance its inventory of heavy oil thermal developments in the first quarter of 2016. These long-life developments are being built with modular, repeatable designs and will require low sustaining capital once brought online. Total heavy oil thermal production, including the Tucker thermal development, averaged 72,500 bbls/day in the first quarter of 2016. Operating costs, inclusive of energy, averaged $6.63/bbl for heavy oil thermal developments in the Lloydminster region and $7.41/bbl at the Tucker thermal development.

The following table lists the design capacity, percentage completion and first production expectations for the Company's near-term heavy oil thermal developments:

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	First Production Expected
Edam East	10,000	100%	On production
Vawn	10,000	87%	Q3 2016
Edam West	4,500	89%	Q3 2016

First oil was achieved at the Edam East heavy oil thermal development on April 18, 2016.

At the 10,000 bbls/day Vawn heavy oil thermal development, construction is approximately 87 percent complete with first production expected in the third quarter of 2016.

At the 4,500 bbls/day Edam West heavy oil thermal development, construction is approximately 89 percent complete with first production expected in the third quarter of 2016.

The Rush Lake heavy oil thermal development, which commenced production in July 2015, averaged production of 12,900 bbls/day in the first quarter of 2016. In addition, the Company sanctioned a second 10,000 bbls/day heavy oil thermal development, Rush Lake 2, in November 2015. Development of Rush Lake 2 will be paced to reflect the Company's prudent capital management in a low commodity price environment.

Development of the Colony formation at the Tucker thermal project in the Cold Lake region commenced in 2015 and achieved first production on April 19, 2016. This formation has similar characteristics to heavy oil thermal reservoirs in the Lloydminster region. Total production from Tucker is expected to reach approximately 20,000 bbls/day in the second half of 2016.

Asia Pacific Region

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block in the first quarter of 2016.

At the liquids-rich BD field, wellhead platform and pipeline infrastructure construction is ongoing and approximately 70 percent complete. Construction of an FPSO vessel to process gas and liquids production from the BD field is approximately 65 percent complete. Development well drilling is underway. Production from the development is expected to commence in the 2017 timeframe.

At the MDA, MBH and MDK gas fields, the tendering process for a floating production vessel has been completed and is awaiting government approval. Tendering is underway for related engineering, procurement, construction and installation contracts. The Company has secured a gas sales agreement for the first tranche of gas from the MDA and MBH fields, which will be developed in tandem. Negotiations of gas sales agreements for the remaining available tranches of gas sales from the MDA, MBH and MDK gas fields are in progress. Production from the MDA, MBH and MDK fields is expected in the 2018 - 2019 timeframe. Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be approximately 100 mmcf/day of gas and 2,400 boe/day of associated NGLs once fully ramped up.

Anugerah

During 2015, Husky acquired two-dimensional and three-dimensional seismic survey data on the contract area. Results from analysis of the data continue to be evaluated to determine the potential for future drilling opportunities.

China

Block 29/26

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

Offshore Taiwan

Analysis of the two-dimensional seismic survey data acquired in 2014 on the Company's offshore Taiwan block has been completed and a number of significant structures have been identified on the block. The Company plans to acquire three-dimensional seismic survey data on the most attractive structures during 2017.

Oil Sands

Sunrise Energy Project

Production from Phase 1 of the Sunrise Energy Project continued to ramp up in the first quarter of 2016 averaging 18,600 bbls/day (9,300 bbls/day net Husky share) which included the impact of a completed maintenance turnaround. The turnaround, originally scheduled for the second quarter of 2016, was advanced to accommodate maintenance on third party pipeline infrastructure. Following the turnaround, production ramped back up to 28,200 bbls/day (14,100 bbls/day net Husky share) as at March 31, 2016. The oil treatment equipment at Plant 1B was brought on line during the quarter providing additional bitumen processing capacity. The steam-oil ratio (“SOR”) continues to steadily improve towards the design SOR of 3.0, while the oil cut is in line with the recommended range at this stage of ramp up of 22-23 percent. Production from the Sunrise Energy Project is expected to ramp up to 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016.

Atlantic Region

White Rose Field and Satellite Extensions

The Company has secured the Henry Goodrich drilling rig for a two-year drilling program. The rig will be utilized for further development drilling at the South White Rose extension and the completion of North Amethyst's Hibernia formation production well.

The Company continues to assess potential development options for the West White Rose satellite extension. One of the two concepts being assessed, a fixed wellhead platform, received government and regulatory approvals in 2015. A subsea option to develop the field is also being evaluated.

Atlantic Exploration

An exploration and appraisal drilling program continued at the Bay du Nord discovery in the Flemish Pass Basin in the first quarter of 2016. Evaluations of results are ongoing.

Western Canada Resource Play Development

Oil and Natural Gas Resource Plays

Overall resource play production in Western Canada averaged approximately 40,300 boe/day in the first quarter of 2016, with current development primarily focused on the Ansell multi-zone natural gas resource play. Production from Ansell was approximately 22,800 boe/day in the first quarter of 2016.

Infrastructure and Marketing

Pipelines and Terminals

Construction is approximately 80 percent complete on the expansion of the Saskatchewan Gathering System which will accommodate production from the Company's heavy oil thermal developments. Production from the Rush Lake thermal development is flowing in a completed section of the newly expanded pipeline system into Lloydminster. The expansion is expected to be completed in the third quarter of 2016.

4.2 Downstream

Canadian Refined Products

Husky and Imperial Oil entered into a contractual agreement in the second half of 2015 to create a single expanded truck transport network of approximately 160 sites. The agreement is subject to regulatory approval by Canada's Competition Bureau and other closing conditions.

Lima Refinery

The Company is proceeding with the initial stages of a crude oil flexibility project designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The crude oil flexibility project will allow the Refinery to swing between light and heavy crude oil feedstock. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.

BP-Husky Toledo, Ohio Refinery

The Company is proceeding with a feedstock optimization project designed to improve the Refinery’s ability to process Hi-TAN crude. Targeted completion of the required metallurgy changes will be performed during the Refinery’s turnaround starting in the second quarter of 2016. Once the upgrades are complete, the Refinery will have the ability to process up to an additional 35,000 bbls/day of Hi-TAN crude. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.

5. Results of Operations

5.1 Upstream

Exploration and Production

Exploration and Production Earnings (Loss) Summary *($ millions)*	Three months ended March 31, 2016	2015
Gross revenues	**836**	1,355
Royalties	**(54)**	(130)
Net revenues	**782**	1,225
Purchases of crude oil and products	**12**	9
Production, operating and transportation expenses	**451**	512
Selling, general and administrative expenses	**42**	69
Depletion, depreciation and amortization	**562**	719
Exploration and evaluation expenses	**17**	57
Other – net	**—**	(15)
Share of equity investment	**1**	—
Financial items	**40**	35
Recovery of income taxes	**(93)**	(42)
Net loss	**(250)**	(119)

Exploration and Production net revenues decreased by $443 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to significant declines in global crude oil and North American natural gas benchmark prices combined with lower NGLs and natural gas production from the Liwan Gas Project in the Asia Pacific Region. The decline in Exploration and Production net revenues compared to the same period in 2015 was partially offset by lower royalties and a weaker Canadian dollar.

Operating costs decreased by $61 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to cost savings initiatives, lower maintenance costs resulting from mild weather conditions in Western Canada and lower energy costs.

DD&A expense decreased in the first quarter of 2016 compared to the first quarter of 2015 primarily due to a reduced depletion base resulting from an impairment charge recognized on certain crude oil and natural gas assets located in Western Canada during the third quarter of 2015. The impairment charge reduced the carrying value of the Company's depletable asset base and resulted in a lower DD&A expense per unit of production in the first quarter of 2016. In addition, production was lower from the Liwan Gas Project which carries a higher per unit of production DD&A expense. In the first quarter of 2016, total DD&A averaged $18.13/boe compared to $22.45/boe in the first quarter of 2015.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended March 31, 2016	2015
Crude oil and NGLs *($/bbl)*		
Light and Medium crude oil	**39.65**	56.91
NGLs	**31.89**	45.29
Heavy crude oil	**18.12**	32.97
Bitumen	**12.83**	34.97
Total crude oil and NGLs average	**24.41**	43.43
Natural gas average *($/mcf)*	**4.41**	5.96
Total average *($/boe)*	**25.02**	40.84

The average sales prices realized by the Company for crude oil and NGLs production decreased by 44 percent in the first quarter of 2016 compared to the same period in 2015 primarily due to significantly lower crude oil benchmarks. The impact of weaker crude oil benchmarks, resulting from the supply and demand market imbalance, was partially mitigated by a weaker Canadian dollar. The average sales prices realized by the Company for natural gas production decreased by 26 percent in the first quarter of 2016 compared to the same period in 2015. The decrease in realized natural gas pricing was primarily due to lower fixed priced natural gas production from the Liwan Gas Project relative to total natural gas production and significantly lower North American natural gas benchmarks, partially mitigated by a weaker Canadian dollar.

Daily Gross Production

Daily Gross Production	Three months ended March 31, 2016	2015
Crude Oil and NGLs *(mbbls/day)*		
Western Canada		
Light and Medium crude oil	33.0	38.8
NGLs	8.8	9.7
Heavy crude oil	61.5	71.9
Bitumen[1]	72.5	55.7
	175.8	176.1
Oil Sands		
Sunrise – bitumen	9.3	—
Atlantic Region		
White Rose and Satellite Fields – light crude oil	36.1	33.6
Terra Nova – light crude oil	4.4	8.1
	40.5	41.7
Asia Pacific Region		
Wenchang – light crude oil	7.4	8.0
Liwan and Wenchang – NGLs[2]	5.2	10.7
	12.6	18.7
	238.2	236.5
Natural gas *(mmcf/day)*		
Western Canada	508.7	524.2
Asia Pacific Region[2]	109.9	192.8
	618.6	717.0
Total *(mboe/day)*	341.3	356.0

(1) *Bitumen consists of production from heavy oil thermal developments and the Tucker thermal development located near Cold Lake, Alberta. Heavy oil thermal average daily gross production was 56.3 mbbls/day for the three months ended March 31, 2016 compared to 45.5 mbbls/day for the three months ended March 31, 2015.*

(2) *Reported production volumes for the three months ended March 31, 2015 include an incremental share of production volumes allocated to Husky for exploration cost recoveries. The incremental share of production volumes ceased during the second quarter of 2015 reflecting the completion of cost recoveries from the Liwan 3-1 field.*

Crude Oil and NGLs Production

Crude oil and NGLs production increased in the first quarter of 2016 primarily due to new production from the Rush Lake heavy oil thermal development, the Sunrise Energy Project, and the South White Rose extension combined with strong performance from the Tucker thermal development. The increases were partially offset by natural reservoir declines from mature properties in Western Canada and the Atlantic Region with limited sustaining capital investment in a low commodity price environment. In addition, NGLs production was lower from the Liwan Gas Project in the Asia Pacific Region primarily due to a reversion of the Company's entitlement share of production at Liwan 3-1 to 49 percent, from approximately 76 percent, following the completion of Liwan 3-1 field exploration cost recoveries in May 2015.

Natural Gas Production

Natural gas production decreased in the first quarter of 2016 by 98.4 mmcf/day compared to the first quarter of 2015 primarily due to lower production from the Liwan Gas Project where the Company's entitlement share of production volumes reverted back to 49 percent in late May 2015 following the completion of exploration cost recoveries from the Liwan 3-1 field. In addition, sales decreased at the Liwan 3-1 field due to the unscheduled isolation and temporary repair in the gas buyer's onshore gas pipeline infrastructure. Payments for natural gas were only made by the buyer for the volumes sold. Husky is pursuing full payments in accordance with the take or pay contractual requirements.

2016 Production Guidance

The following table shows actual daily production for the three months ended March 31, 2016 and the year ended December 31, 2015, as well as the previously issued production guidance for 2016.

	Guidance[(1)] 2016	Actual Production: Three months ended March 31, 2016	Actual Production: Year ended December 31, 2015
Canada			
Light and Medium crude oil *(mbbls/day)*	66 - 68	74	73
NGLs *(mboe/day)*	7 - 8	9	9
Heavy crude oil & bitumen *(mbbls/day)*	142 - 157	143	132
Natural gas *(mmcf/day)*	380 - 430	509	514
Canada total *(mboe/day)*	279 - 305	311	300
Asia Pacific			
Light crude oil *(mbbls/day)*	6 - 7	7	8
NGLs *(mboe/day)*	7 - 8	5	9
Natural gas *(mmcf/day)*	140 - 150	110	175
Asia Pacific total *(mboe/day)*	36 - 40	30	46
Total *(mboe/day)*	315 - 345	341	346

(1) *Production guidance does not reflect the impact of potential asset dispositions in Western Canada.*

Royalties

In the first quarter of 2016, royalty rates as a percentage of gross revenues averaged seven percent compared to 10 percent in the same period in 2015. Royalty rates in Western Canada averaged six percent in the first quarter of 2016 compared to 11 percent in the same period in 2015 primarily due to lower commodity prices with a sliding scale price sensitivity rate. Royalty rates for the Atlantic Region averaged 11 percent in the first quarter of 2016 compared to 14 percent in the same period in 2015 primarily due to lower production and lower crude oil prices, partially offset by lower eligible royalty costs in the first quarter of 2016. Royalty rates in the Asia Pacific Region averaged five percent in both the first quarter of 2016 and 2015.

Operating Costs

($ millions)	Three months ended March 31, 2016	2015
Western Canada	366	426
Atlantic Region	52	50
Asia Pacific Region	24	21
Operating costs	442	497
Unit operating costs ($/boe)	13.31	14.87

Total Exploration and Production operating costs were $442 million in the first quarter of 2016 compared to $497 million in the same period in 2015. Total unit operating costs averaged $13.31/boe in the first quarter of 2016 compared to $14.87/boe in the same period in 2015.

Unit operating costs in Western Canada averaged $13.74/boe in the first quarter of 2016 compared to $17.12/boe in the same period in 2015. The decrease in unit operating costs per boe was primarily attributable to cost savings initiatives, mild weather conditions and lower energy costs in the first quarter of 2016.

Unit operating costs in the Atlantic Region averaged $14.20/boe in the first quarter of 2016 compared to $13.36/boe in the same period in 2015. The increase in unit operating costs per boe was primarily attributable to lower production combined with higher logistics costs due to absence of a drilling rig in the first quarter of 2016.

Unit operating costs in the Asia Pacific Region averaged $8.38/boe in the first quarter of 2016 compared to $4.51/boe in the same period in 2015. The increase in unit operating costs per boe was primarily attributable to lower production at the Liwan Gas Project combined with higher vessel, chemical and fuel costs.

Exploration and Evaluation Expenses

($ millions)	Three months ended March 31, 2016	2015
Seismic, geological and geophysical	16	21
Expensed drilling	—	32
Expensed land	1	4
Exploration and evaluation expenses	17	57

Exploration and evaluation expenses in the first quarter of 2016 were $17 million compared to $57 million in the first quarter of 2015. Expensed drilling in the first quarter of 2015 primarily related to the write-off of the Aster exploration well in the Atlantic Region.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were lower in the first quarter of 2016 and reflected the Company's prudent capital management in a low commodity price environment.

Exploration and Production Capital Expenditures[(1)]

($ millions)	Three months ended March 31, 2016	2015
Exploration		
Western Canada conventional and resource plays	2	5
Heavy Oil	3	7
Atlantic Region	11	60
	16	72
Development		
Western Canada conventional and resource plays	45	162
Heavy Oil	75	257
Oil Sands	11	83
Atlantic Region	17	127
Asia Pacific Region[(2)]	11	21
	159	650
Acquisitions		
Heavy Oil	—	1
	175	723

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *Capital expenditures in the Asia Pacific Region exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture which is accounted for under the equity method.*

Western Canada Conventional and Resource Plays

During the first quarter of 2016, $47 million (27 percent) was invested in Western Canada conventional and resource plays, compared to $167 million (23 percent) in the same period in 2015, primarily on the development of the Company's natural gas resource plays including the Ansell multi-zone.

Heavy Oil

During the first quarter of 2016, $78 million (45 percent) was invested in Heavy Oil, compared to $265 million (37 percent) in the same period in 2015, primarily on the development of the Company's heavy oil thermal developments including Edam East, Edam West, Vawn and the Colony formation at Tucker.

Oil Sands

During the first quarter of 2016, $11 million (six percent) was invested in Oil Sands, compared to $83 million (11 percent) in the same period in 2015, primarily on Phase 1 of the Sunrise Energy Project.

Atlantic Region

During the first quarter of 2016, $28 million (16 percent) was invested in the Atlantic Region, compared to $187 million (26 percent) in the same period in 2015, primarily on the development of the White Rose extension projects, including the West White Rose and South White Rose extension satellite fields and on further exploration and appraisal of the Bay du Nord discovery in the Flemish Pass Basin.

Asia Pacific Region

During the first quarter of 2016, $11 million (six percent) was invested in the Asia Pacific Region, compared to $21 million (three percent) in the same period in 2015, primarily on the Liwan Gas Project.

Exploration and Production Wells Drilled

The following table discloses the number of wells drilled in Heavy Oil, Oil Sands and Western Canada conventional and resource plays during the three months ended March 31, 2016 and 2015:

	Three months ended March 31,			
	2016		2015	
Wells Drilled[1]	Gross	Net	Gross	Net
Heavy Oil	36	36	35	34
Oil Sands	—	—	6	3
Western Canada conventional and resource plays	2	1	23	14
	38	37	64	51

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

During the first quarter of 2016, the Company's onshore drilling was focused primarily on the development of Heavy Oil. Oil Sands and Western Canada conventional and resource plays related drilling and completion activity has been substantially curtailed due to limited capital investment in a low commodity price environment. There were no offshore wells drilled during the first quarter of 2016.

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGLs, 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 U.S. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the U.S. market.

Infrastructure and Marketing Earnings Summary	Three months ended March 31,	
($ millions)	2016	2015
Gross revenues	215	366
Purchases of crude oil and products	171	335
Infrastructure gross margin	44	31
Marketing and other	(102)	69
Infrastructure and Marketing gross margin	(58)	100
Production, operating and transportation expenses	8	9
Selling, general and administrative expenses	1	2
Depletion, depreciation and amortization	6	5
Other – net	(3)	(1)
Provisions for (recovery of) income taxes	(19)	22
Net earnings (loss)	(51)	63

Infrastructure and Marketing gross revenues and purchases of crude oil and products decreased by $151 million and $164 million, respectively, in the first quarter of 2016 compared to the first quarter of 2015 primarily due to significantly lower commodity prices.

Marketing and other decreased by $171 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to narrower product and location differentials between Canada and the U.S. which resulted in fewer arbitrage opportunities and significant mark to market losses.

Infrastructure and Marketing Capital Expenditures

In the first quarter of 2016, Infrastructure and Marketing capital expenditures totalled $32 million compared to $19 million in the same period in 2015. Capital expenditures in both periods relate primarily to the expansion of the Saskatchewan Gathering System into Lloydminster.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2016**	2015
Gross revenues	**281**	347
Purchases of crude oil and products	**137**	238
Gross margin	**144**	109
Production, operating and transportation expenses	**36**	43
Selling, general and administrative expenses	**1**	1
Depletion, depreciation and amortization	**28**	26
Other – net	**—**	(11)
Provisions for income taxes	**21**	13
Net earnings	**58**	37
Upgrader throughput *(mbbls/day)*[(1)]	**77.6**	83.7
Total sales *(mbbls/day)*	**78.3**	81.0
Synthetic crude oil sales *(mbbls/day)*	**57.7**	58.5
Upgrading differential *($/bbl)*	**22.23**	15.72
Unit margin *($/bbl)*	**20.21**	14.95
Unit operating cost *($/bbl)*[(2)]	**5.10**	5.71

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

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

Upgrader gross revenues decreased by $66 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to lower realized prices for synthetic crude oil and low sulphur distillates combined with lower throughput and sales volumes. Throughput decreased by 6.1 mbbls/day, or seven percent, and sales volumes decreased by 2.7 mbbls/day, or three percent, compared to the first quarter of 2015. Throughput decreased primarily due to unscheduled maintenance completed in the quarter.

Upgrader gross margin increased by $35 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to a higher average upgrading differential. During the first quarter of 2016, the upgrading differential averaged $22.23/bbl, an increase of $6.51/bbl, or 41 percent compared to the first quarter of 2015. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The increase in upgrading differential was attributable to significantly lower heavy crude oil feedstock costs partially offset by lower realized prices for Husky Synthetic Blend. During the first quarter of 2016, the price of Husky Synthetic Blend averaged $45.99/bbl compared to $55.51/bbl in the first quarter of 2015.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2016**	2015
Gross revenues	**435**	601
Purchases of crude oil and products	**339**	483
Gross margin		
Fuel	**26**	33
Refining	**17**	28
Asphalt	**39**	44
Ancillary	**14**	13
	96	118
Production, operating and transportation expenses	**49**	63
Selling, general and administrative expenses	**7**	10
Depletion, depreciation and amortization	**24**	25
Other – net	**(1)**	1
Financial items	**2**	1
Provisions for income taxes	**4**	5
Net earnings	**11**	13
Number of fuel outlets[(1)]	**481**	488
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**6.2**	7.6
Fuel sales per retail outlet *(thousands of litres/day)*	**11.1**	12.4
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**11.0**	11.4
Lloydminster Refinery *(mbbls/day)*	**28.0**	29.2
Ethanol production *(thousands of litres/day)*	**810.7**	775.5

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

Canadian Refined Products gross revenues decreased by $166 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to lower refined product prices and lower fuel sales volumes and demand resulting from a weak economic environment. Fuel sales per retail outlet decreased by 1,300 litres/day, or 10 percent, compared to the first quarter of 2015.

Fuel gross margins decreased by $7 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to lower fuel sales volumes and demand resulting from a weak economic environment.

Refining gross margins decreased by $11 million in the first quarter of 2016 compared to the first quarter of 2015. Gross margins were $6 million lower at the Prince George Refinery primarily due to lower diesel rack prices which were partially offset by lower crude oil feedstock costs. Gross margins were $5 million lower at the Lloydminster and Minnedosa Ethanol plants primarily due to higher grain feedstock costs.

Asphalt gross margins decreased by $5 million in the first quarter of 2016 compared to the first quarter of 2015 primarily due to lower refined product prices partially offset by lower heavy crude oil feedstock costs.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2016**	2015
Gross revenues	**1,126**	1,725
Purchases of crude oil and products	**1,040**	1,539
Gross margin	**86**	186
Production, operating and transportation expenses	**137**	128
Selling, general and administrative expenses	**3**	3
Depletion, depreciation and amortization	**81**	69
Other – net	**(125)**	—
Financial items	**1**	1
Recovery of income taxes	**(4)**	(209)
Net earnings (loss)	**(7)**	194
Select operating data:		
Lima Refinery throughput *(mbbls/day)*	**127.5**	119.2
BP-Husky Toledo Refinery throughput *(mbbls/day)*[(1)]	**69.4**	56.3
Refining margin *(U.S. $/bbl crude throughput)*	**3.76**	10.04
Refinery inventory *(mmbbls)*[(2)]	**10.1**	10.7

(1) *Prior period BP-Husky Toledo Refinery throughput was revised in the first quarter of 2016 to reflect total throughput. Prior periods reflected crude throughput.*
(2) *Included in refinery inventory is feedstock and refined products.*

U.S. Refining and Marketing gross revenues decreased by $599 million in the first quarter of 2016 compared to the same period in 2015 primarily due to lower realized refined product prices consistent with significantly lower Chicago Regular Unleaded Gasoline and Chicago Ultra-low Sulphur Diesel benchmark prices. The decreases were partially offset by a weaker Canadian dollar and higher throughput at the Lima and BP-Husky Toledo Refineries. In the first quarter of 2015, the Lima Refinery was negatively impacted by an unplanned outage when a fire occurred in the isocracker unit and the BP-Husky Toledo Refinery was negatively impacted by unplanned maintenance to repair a damaged fluid catalytic cracking unit. Throughputs at the Lima and BP-Husky Toledo Refineries increased by 8.3 mbbls/day and 13.1 mbbls/day, respectively, when compared to the first quarter of 2015.

U.S. Refining and Marketing purchases decreased by $499 million in the first quarter of 2016 compared to the same period in 2015 primarily due to lower crude oil feedstock costs.

U.S. Refining and Marketing gross margin decreased by $100 million in the first quarter of 2016 compared with the first quarter of 2015 primarily due to significantly lower Chicago 3:2:1 crack spreads which are reflected in refining margins. The decrease was partially offset by higher throughput at the Lima and BP-Husky Toledo Refineries.

In the first quarter of 2016, the Company accrued business interruption and property damage insurance recoveries of $123 million associated with the Company's isocracker unit fire at Lima, bringing total insurance recoveries to date of $358 million up to March 31, 2016. The insurance recoveries are reflected in other – net.

In the first quarter of 2015, the Company recorded a deferred income tax recovery of $203 million related to the partial payment of the contribution payable to BP-Husky Refining LLC.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out (“LIFO”) accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on FIFO accounting, which reflects purchases made in previous months. The estimated FIFO impact was a reduction in net earnings of approximately $21 million in the first quarter of 2016 compared to a reduction in net earnings of $9 million the first quarter of 2015.

Downstream Capital Expenditures

In the first quarter of 2016, Downstream capital expenditures totalled $196 million compared to $61 million in the same period in 2015. In Canada, capital expenditures of $14 million were primarily related to projects at the Upgrader and Prince George Refinery. At the Lima Refinery, $150 million was spent primarily on upgrades to the isocracker unit in addition to various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $32 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)	**2016**	2015
Selling, general and administrative expenses	**(63)**	(20)
Depreciation and amortization	**(21)**	(20)
Other – net	**(66)**	—
Net foreign exchange gain	**13**	62
Finance income	**5**	1
Finance expense	**(64)**	(14)
Recovery of income taxes	**(23)**	(6)
Net income (loss)	**(219)**	3

The Corporate segment reported a net loss of $219 million in the first quarter of 2016 compared to net income of $3 million in the first quarter of 2015. Selling, general and administrative expenses increased by $43 million primarily due to an increase in stock-based compensation expense and re-organization costs recognized in the first quarter of 2016. Other – net expense of $66 million in the first quarter of 2016 related primarily to unrealized losses on the Company's short-term hedging program. Foreign exchange gain decreased by $49 million due to the strengthening of the Canadian dollar against the U.S. dollar from December 31, 2015 to March 31, 2016 which impacted the translation of the Company's foreign currency denominated non-cash working capital. Finance expense increased by $50 million primarily due to higher debt and a decrease in the amount of capitalized interest.

Foreign Exchange Summary	Three months ended March 31,	
($ millions, except where indicated)	**2016**	2015
Loss on translation of U.S. dollar denominated long-term debt	**—**	(27)
Gain (loss) on non-cash working capital	**(13)**	55
Other foreign exchange gain	**26**	34
Net foreign exchange gain	**13**	62
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S $0.723**	U.S. $0.862
At end of period	**U.S $0.771**	U.S. $0.788

Included in other foreign exchange gain are realized and unrealized foreign exchange gains and losses on working capital and intercompany financing. The foreign exchange gains and losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period. The Company manages its exposure to foreign currency fluctuations in order to minimize the impact of foreign exchange gains and losses on the Condensed Interim Consolidated Financial Statements.

Consolidated Income Taxes

	Three months ended March 31,	
($ millions)	**2016**	2015
Recovery of income taxes	**68**	205
Cash income taxes recovered	**35**	4

Consolidated income taxes were a recovery of $68 million in the first quarter of 2016 compared to $205 million in the first quarter of 2015. The decrease was primarily due to a deferred income tax recovery of $203 million related to 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 in the first quarter of 2015.

6. Liquidity and Capital Resources

6.1 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include cash flow from operations, proceeds from the issuance of equity, proceeds from the issuance of short and long-term debt, availability of short and long-term credit facilities and proceeds from asset sales. Since the Company operates in the Upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt.

During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. The Company continues to believe that it has sufficient liquidity to sustain its operations, fund capital programs and meet non-cancellable contractual obligations and commitments, including any working capital deficiencies, in the short and long-term principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of debt and borrowings under committed and uncommitted credit facilities. 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, 2016, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1]	**645**	**363**
Syndicated credit facilities[2]	**4,000**	**2,294**
	4,645	**2,657**

[1] *Consists of demand credit facilities.*
[2] *Commercial paper outstanding is supported by the Company's syndicated credit facilities.*

At March 31, 2016, Husky had $2,657 million of unused credit facilities of which $2,294 million are long-term committed credit facilities and $363 million are short-term uncommitted credit facilities. A total of $272 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $858 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper. At March 31, 2016 the Company had direct borrowings of $848 million against committed credit facilities and $10 million against uncommitted credit facilities. The Company's ability to renew existing bank credit facilities on favourable terms and raise new debt on favourable terms is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

Working capital is the amount by which current assets exceed current liabilities. At March 31, 2016, working capital deficiency was $629 million compared to a working capital deficiency of $922 million at December 31, 2015. The Company had sufficient sources of liquidity to supplement the working capital deficiency as at March 31, 2016.

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, 2016.

On February 23, 2015, the Company filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada (the "Canadian Shelf Prospectus") that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including March 23, 2017.

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

In March 2016, holders of 1,564,068 Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") exercised their option to convert their shares, on a one-for-one basis, to Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares") and receive a floating rate quarterly dividend. The dividend rate applicable to the Series 2 Preferred Shares for the three month period commencing March 31, 2016 to, but excluding, June 30, 2016 is equal to the sum of the Government of Canada 90 day treasury bill rate on March 1, 2016 plus 1.73 percent, being 2.192 percent. The floating rate quarterly dividend applicable to the Series 2 Preferred Shares will be reset every quarter. The dividend rate applicable to the Series 1 Preferred Shares for the five year period commencing March 31, 2016, to, but excluding, March 31, 2021 is equal to the sum of the Government of Canada five year bond yield on March 1, 2016 plus 1.73 percent, being 2.404 percent. Both rates were calculated according to the terms described in the prospectus supplement dated March 11, 2011.

On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020. In addition, the Company's leverage covenant was replaced by a debt to capital covenant calculated as total debt and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. The Company was in compliance with the syndicated credit facility covenants at March 31, 2016 and assesses the risk of non-compliance to be low. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated.

The Company has $1.9 billion in unused capacity under the Canadian Shelf Prospectus and U.S. $3.0 billion in unused capacity under the U.S. Shelf Prospectus and related U.S. registration statement as at March 31, 2016. The ability of the Company to utilize the capacity under its Canadian Shelf Prospectus and U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

6.2 Capital Structure

Capital Structure		**March 31, 2016**
($ millions)	**Outstanding**	**Available**[1]
Total debt[2]	**6,977**	**2,657**
Common shares, preferred shares, retained earnings and other reserves	**16,104**	

[1] *Total debt available includes committed and uncommitted credit facilities.*
[2] *Total debt is equal to long-term debt including long-term debt due within one year and short-term debt*

The Company considers its capital structure to include shareholders' equity and debt which was $23.1 billion at March 31, 2016 (December 31, 2015 – $23.3 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to cash flow from operations (refer to section 11). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to cash flow from operations ratio of less than 1.5 times. At March 31, 2016, debt to capital employed was 30.2 percent (December 31, 2015 – 28.9 percent) and debt to cash flow from operations was 2.4 times (December 31, 2015 – 2.0 times), exceeding the Company's targets.

The increase in the Company's debt to capital employed and debt to cash flow from operations ratios as at March 31, 2016 reflects the impact of lower global crude oil and North American natural gas benchmark pricing which resulted in significantly lower cash flow from operations. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle including but not limited to a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the continued transition to low sustaining capital projects and the planned disposition of select legacy Upstream assets in Western Canada. In addition, the Board approved the disposition of select midstream assets on April 25, 2016 for gross proceeds of $1.7 billion. The proceeds from the midstream assets disposition and the potential proceeds from the select legacy Upstream asset dispositions would generate cash proceeds and allow the Company to pay down debt which would serve to strengthen the Company's balance sheet. The disposition of the selected midstream assets is subject to regulatory approval.

6.3 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other 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 2015 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2015. During the first quarter of 2016, there were no material changes to the Company's contractual obligations or non-cancellable commitments.

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 effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

Standby Letters of Credit

On occasion, the Company issues letters of credit in connection with transactions in which the counterparty requires such security.

6.4 Transactions with Related Parties

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. In the first quarter of 2016, the amount of natural gas sales to Meridian totalled $11 million, the amount of steam purchased by the Company from Meridian totalled $3 million and the total cost recovery by the Company for facilities services was $6 million. At March 31, 2016, the Company had under $1 million due from Meridian with respect to these transactions.

At March 31, 2016, $35 million of the May 11, 2009 7.25% senior notes were held by related parties and are included in long-term debt in the Company's consolidated balance sheet. Mr. Canning Fok, co-chair and a director of the Company, indirectly subscribed for $3 million of the senior notes. Ace Dimension Limited subscribed for $32 million of the senior notes. These related party transactions were measured at fair market value at the date of the transactions and have been carried out on the same terms as applied with unrelated parties.

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

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

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 2015 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, 2015, as discussed in Husky's 2015 Annual MD&A.

7.2 Financial Risks

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

Commodity Price Risk Management

Husky uses derivative commodity instruments, including commodity put and call options under a short-term hedging program, 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 meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable, inventory, other assets, accounts payable and accrued liabilities and other liabilities.

At March 31, 2016, 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. During the first quarter of 2016 the Company announced a short-term hedging program designed to manage downside commodity price risk for a portion of its crude oil production while the Lima and BP-Husky Toledo Refineries undergo major turnarounds. The hedging program is expected to conclude in mid-2016, coinciding with the completion of the refinery turnarounds. Refer to the Commodity Risk Management disclosure within Note 15 of the Condensed Interim Consolidated Financial Statements.

WTI and Brent Crude Oil Call and Put Option Contracts[(1)]

Type	Term	Volume (bbls/day)	Sold Call Price (US$bbl)	Bought Put Price (US$bbl)
WTI call options	April - June 2016	71,700	39.80	—
WTI put options	April - June 2016	86,100	—	30.38
Brent call options	April - June 2016	26,600	40.65	—
Brent put options	April - June 2016	32,800	—	31.31

(1) *Prices reported are the weighted average prices for the period.*

Interest Rate Risk Management

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. In order to manage interest rate risk and the resulting interest expense, the Company mitigates some of its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of its credit facilities and various financial instruments. The optimal mix maintained will depend on market conditions. The Company may also enter into interest rate swaps from time to time as an additional means of managing current and future interest rate risk.

During 2014, the Company discontinued its cash flow hedge with respect to forward starting interest rate swaps. These forward starting interest rate swaps were settled and derecognized. 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, 2016, the balance in other reserves related to the accrued gain was $19 million (December 31, 2015 – $20 million), net of tax of $7 million (December 31, 2015 – net of tax of $7 million). The amortization of the accrued gain resulted in an offset to finance expenses of less than $1 million for the three months ended March 31, 2016. Refer to the Interest Rate Risk Management disclosure within Note 15 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At March 31, 2016, 68 percent or $4.1 billion of Husky's outstanding long-term debt was denominated in U.S. dollars. No long-term debt, including amounts due within one year, is exposed to changes in the Canadian/U.S. exchange rate, as all U.S. denominated debt has been designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

At March 31, 2016, the Company had designated all of its U.S. $3.2 billion denominated debt as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency. For the three months ended March 31, 2016, the Company incurred an unrealized gain of $239 million arising from the translation of the debt, net of tax of $38 million which was recorded in hedge of net investment within 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, 2016, Husky's share of this obligation was U.S. $229 million including accrued interest. At March 31, 2016, the cost of a Canadian dollar in U.S. currency was $0.771.

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 2015 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. Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

IFRS 16 Leases

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

Amendments to IAS 7 Statement of Cash Flows

In January 2016, the IASB issued amendments to IAS 7 to be applied prospectively for annual periods beginning or after January 1, 2017 with early adoption permitted. The amendments require disclosure of information enabling users of financial statements to evaluate changes in liabilities arising from financing activities. The Company is currently evaluating the impact of adopting the amendments on the consolidated financial statements.

IFRS 15 Revenue from Contracts with Customers

In April 2016, the IASB published an amendment to IFRS 15. The amendments have the same effective date as the standard and will be applied to annual periods beginning on or after January 1, 2018. Early adoption is permitted. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

Changes in Accounting Policies

Effective January 1, 2016, the Company adopted the following new accounting standards issued by the IASB:

Amendments to IAS 1 Presentation of Financial Statements

The amendments clarify guidance on materiality and aggregation, use of subtotals, aggregation and disaggregation of financial statement line items, the order of the notes to the financial statements and disclosure of significant accounting policies. The adoption of this amended standard has no material impact on the Company's consolidated financial statements.

Amendments to IFRS 7 Financial Instrument: Disclosures

The amendments clarify:

- whether a servicing contract is continuing involvement in a transferred asset for the purpose of determining the disclosures required; and
- the applicability of the amendments to IFRS 7 on offsetting disclosures to condensed interim financial statements.

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

Amendments to IAS 34 Interim Financial Reporting

The amendments clarify the requirements relating to information required by IAS 34 that is presented elsewhere within the interim financial report but outside the interim financial statements. 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: April 21, 2016:

• common shares	1,005,451,854
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	26,807,529
• stock options exercisable	21,364,312

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 2015 Annual MD&A, the 2015 Consolidated Financial Statements and the 2015 Annual Information Form filed with Canadian securities regulatory authorities and the 2015 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, 2016 are compared to the results for the three months ended March 31, 2015. Discussions with respect to Husky's financial position as at March 31, 2016 are compared to its financial position as at December 31, 2015. 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 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 are presented before the effect of hedging.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended March 31, 2016 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 (loss), cash flow from operations, operating netback, debt to capital employed, earnings coverage, debt to cash flow from operations 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, debt to capital employed, earnings coverage or debt to cash flow from operations. These are useful complementary measures 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 issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP measures are defined below.

Adjusted Net Earnings (Loss)

The term "adjusted net earnings (loss)" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings (loss) is comprised of net earnings (loss) and excludes items such as after-tax property, plant and equipment impairment charges, goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing Husky's financial performance through providing comparability between periods.

For the three months ended March 31, 2016 and 2015 there were no reconciling items between net earnings (loss) and adjusted net earnings (loss).

Cash Flow from Operations

The term "cash flow from operations" is a non-GAAP measure 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 (loss) plus items not affecting cash which include accretion, depletion, depreciation and amortization, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment, unrealized mark to market gains and losses, and other non-cash items.

The following table shows the reconciliation of net earnings (loss) to cash flow from operations and related per share amounts for the three months ended March 31, 2016 and 2015:

	Three months ended March 31,	
($ millions)	**2016**	2015
Net earnings (loss)	**(458)**	191
Items not affecting cash:		
Accretion	**34**	30
Depletion, depreciation and amortization	**722**	864
Deferred income taxes	**(7)**	(259)
Foreign exchange	**1**	28
Stock-based compensation	**17**	(10)
Loss on sale of assets	**2**	8
Unrealized mark to market	**123**	(34)
Other	**—**	20
Cash flow from operations	**434**	838
Cash flow from operations – basic	**0.43**	0.85
Cash flow from operations – diluted	**0.43**	0.85

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

Debt to Cash Flow from Operations

Debt to cash flow from operations is a non-GAAP measure and is equal to total debt divided by cash flow from operations. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

Earnings Coverage

Earnings coverage is a non-GAAP measure and is equal to net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt. The Company's earnings coverage on long-term debt was negative 15.4 times for the twelve month period ended March 31, 2016.

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

Unless otherwise noted, historical production numbers given represent Husky’s share.

The Company uses the term barrels of oil equivalent ("boe"), which is consistent with other oil and gas producers' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

Terms

Adjusted Net Earnings (Loss)	*Net earnings (loss) before after-tax property, plant and equipment impairment charges, goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs*
Bitumen	*Bitumen is a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital Employed	*Long-term debt, long-term debt due within one year, short-term debt 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 (loss) plus items not affecting cash which include accretion, depletion, depreciation and amortization, inventory write-downs to net realizable value, 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 short-term debt divided by capital employed*
Debt to Cash Flow from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by cash flow from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate transmissibility of the oil through a pipeline*
Earnings Coverage	*Net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt*
Feedstock	*Raw materials which are processed into petroleum products*
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 Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Heavy crude oil	*Crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity*
Hi-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as Hi-TAN crudes*
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*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
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*
Oil cut	*Oil cut is the percentage of a barrel of liquids produced that represents oil*
Oil sands	*Sands and other rock materials that contain crude bitumen and include all other mineral substances in association therewith*
Operating Netback	*Net revenues after deduction of operating costs, transportation and royalty payments*
Seismic survey	*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*
Steam-oil ratio	*The steam-oil ratio measures the volume of steam used to produce one unit volume of oil*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
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 short-term debt*
Turnaround	*Performance of plant or facility maintenance*

Abbreviations

bbls	*barrels*	*mboe*	*thousand barrels of oil equivalent*
bbls/day	*barrels per day*	*mboe/day*	*thousand barrels of oil equivalent per day*
boe	*barrels of oil equivalent*	*mcf*	*thousand cubic feet*
boe/day	*barrels of oil equivalent per day*	*MD&A*	*Management's Discussion and Analysis*
DD&A	*depletion, depreciation and amortization*	*mmbbls*	*million barrels*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A.)*	*mmboe*	*million barrels of oil equivalent*
FIFO	*first in first out*	*mmbtu*	*million British Thermal Units*
FPSO	*Floating production, storage and offloading vessel*	*mmcf*	*million cubic feet*
FVTPL	*fair value through profit or loss*	*mmcf/day*	*million cubic feet per day*
GAAP	*Generally Accepted Accounting Principles*	*NGLs*	*natural gas liquids*
GJ	*gigajoule*	*NIT*	*NOVA Inventory Transfer*
IAS	*International Accounting Standard*	*NYMEX*	*New York Mercantile Exchange*
IASB	*International Accounting Standards Board*	*OPEC*	*Organization of Petroleum Exporting Countries*
ICFR	*Internal Controls over Financial Reporting*	*OCI*	*other comprehensive income*
IFRS	*International Financial Reporting Standards*	*RMB*	*Chinese Yuan*
LIFO	*Last in first out*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
mbbls	*thousand barrels*	*WTI*	*West Texas Intermediate*
mbbls/day	*thousand barrels per day*		

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; the Company’s 2016 production guidance, including guidance for specified areas and product types;
- with respect to the Company's Asia Pacific Region: planned timing of first production from the Madura Strait BD, MDA, MBH and MDK fields, and forecasted combined net peak sales volumes for these fields; and anticipated timeframe for acquiring seismic survey data for the offshore Taiwan block;
- with respect to the Company's Atlantic Region: anticipated drilling plans associated with the arrival of the Henry Goodrich drilling rig for the South White Rose extension and North Amethyst Hibernia formation production well;
- with respect to the Company's Oil Sands properties: forecast daily production from the Company’s Sunrise Energy Project by the end of 2016;
- with respect to the Company's Heavy Oil properties: anticipated timing of first production from, and forecast net peak daily production from, the Company’s Edam West and Vawn heavy oil thermal projects; planned development strategy, and forecast net peak daily production from, the Company’s Rush Lake 2 heavy oil thermal development; and anticipated daily production from the Company’s Tucker thermal project in the second half of 2016;
- with respect to the Company's Western Canadian oil and gas resource plays: the Company’s plan to pursue disposition of select Upstream legacy assets in Western Canada, and the anticipated resulting balance sheet impact of the proceeds from the select midstream assets disposition and the potential proceeds from the select legacy Upstream assets disposition;
- with respect to the Company's Infrastructure and Marketing segment: expected timing of completion, and the anticipated benefits, of the expansion of the Saskatchewan Gathering System; and
- with respect to the Company's Downstream operating segment: anticipated timing and anticipated benefits of the crude oil flexibility project at the Lima Refinery; and anticipated timing and benefits of the feedstock optimization project at the BP-Husky Toledo Refinery.

There are numerous uncertainties inherent in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from production estimates.

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, 2015 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.