MANAGEMENT'S DISCUSSION AND ANALYSIS

April 26, 2018

Table of Contents

1.0 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)	**2018**	2017	2017	2017	2017	2016	2016	2016
Production *(mboe/day)*	**300.4**	320.4	317.7	319.5	334.0	327.0	301.0	315.8
Gross revenues and Marketing and other[(1)]	**5,262**	5,534	4,713	4,351	4,348	3,865	3,520	3,261
Net earnings (loss)	**248**	672	136	(93)	71	186	1,390	(196)
Per share – Basic	**0.24**	0.66	0.13	(0.10)	0.06	0.19	1.37	(0.20)
Per share – Diluted	**0.24**	0.66	0.13	(0.10)	0.06	0.19	1.37	(0.20)
Adjusted net earnings (loss)[(2)]	**245**	665	136	10	73	(6)	(100)	(91)
Funds from operations[(2)]	**895**	1,039	891	715	661	662	619	505
Per share – Basic	**0.89**	1.03	0.89	0.71	0.66	0.66	0.62	0.50
Per share – Diluted	**0.89**	1.03	0.89	0.71	0.66	0.66	0.62	0.50

(1) During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.

(2) Adjusted net earnings (loss) and funds from operations are non-GAAP measures. The calculation of funds from operations changed in the second quarter of 2017. Prior periods have been revised to conform to current presentation. Refer to Section 10.3 for a reconciliation to the GAAP measures and an explanation of the changes.

Performance

- Net earnings of $248 million in the first quarter of 2018 compared to net earnings of $71 million in the first quarter of 2017, with the increase primarily due to:
  - Higher earnings from crude oil marketing activities due to the widening of the location pricing differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline;
  - Higher realized upgrading margins;
  - Higher realized U.S. Refining and Marketing margins;
  - Higher throughput in the U.S. Refining and Marketing business segment due to the addition of the Superior Refinery; and
  - Higher realized natural gas prices due to increased natural gas production from Asia Pacific.

  Partially offset by:
  - Lower Upstream realized prices due to the widening of the light/heavy oil differentials; and
  - Lower Upstream production due to the factors described below.
- Funds from operations of $895 million in the first quarter of 2018 compared to $661 million in the first quarter of 2017, with the increase attributed to the same factors noted above for net earnings.
- Production decreased by 33.6 mboe/day or 10 percent to 300.4 mboe/day in the first quarter of 2018 compared to the first quarter of 2017 as a result of:
  - Lower crude oil and natural gas production in Western Canada due to the disposition of select legacy assets in 2017;
  - Lower heavy crude oil production due to a reduction of production in response to the widening of the light/heavy oil differentials;

- Lower crude oil production in Atlantic primarily due to a regulatory suspension of production operations on the *SeaRose* FPSO vessel; and
- Lower crude oil production in Asia Pacific due to the expiry of the Company's participation in Wenchang in the fourth quarter of 2017.

Partially offset by:

- Higher natural gas and natural gas liquids ("NGL") production from the Liwan and BD projects.

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is one of Canada's largest integrated energy companies and is based in Calgary, Alberta. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares Series 1, Series 2, Series 3, Series 5 and Series 7 are listed under the symbols "HSE.PR.A", "HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The Company operates in Canada, the United States and the Asia Pacific region with Upstream and Downstream business segments.

2.1 Corporate Strategy

The Company's business strategy is to focus on returns from investment in a deep portfolio of opportunities that can generate increased funds from operations and free cash flow.

The Company has two main businesses: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific") (Atlantic and Asia Pacific collectively, "Offshore").

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and NGL production from Western Canada, the Lloydminster upgrading and asphalt refining complex, the Prince George Refinery, Husky Midstream Limited Partnership (35 percent working interest and operatorship), and the Lima, Toledo (50 percent working interest) and Superior refineries in the U.S. midwest. Natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic. Each area generates high-netback production, with near and long-term investment potential.

2.2 Operations Overview and Q1 Highlights

Upstream Operations

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and NGL ("Exploration and Production") and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas and storage of crude oil, diluent and natural gas ("Infrastructure and Marketing"). 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 in Western Canada, Asia Pacific and Atlantic.

Exploration and Production

Thermal Developments

The Company continued to advance its inventory of thermal projects in the first quarter of 2018. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total bitumen production, including Lloyd thermal bitumen projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 123,200 bbls/day in the first quarter of 2018.

Lloyd Thermal Bitumen Projects

The Company expects to bring on 60,000 bbls/day of long-life thermal bitumen production over the next three years.

Development continued at the 10,000 bbls/day Rush Lake 2 Thermal Project. Construction of the Central Processing Facility ("CPF") is progressing ahead of schedule and drilling of the 12 Steam-Assisted Gravity Drainage ("SAGD") injector-producer well pairs was completed in the first quarter of 2018. First production is expected in the fourth quarter of 2018.

At Dee Valley, drilling has started and construction on the CPF is scheduled to commence in the second quarter of 2018. At the Spruce Lake North and Central thermal projects, site clearing has started. First production for all three projects is expected in 2020.

In November 2017, the Company sanctioned two new 10,000 bbls/day thermal projects. First production from these two projects is expected in the second half of 2021. Additionally, the Company plans to sanction two new thermal projects in the fourth quarter of 2018.

Tucker Thermal Project

Production from the first 10 wells of the new D West pad commenced in the first quarter of 2018 with the remaining five wells expected to be on production in the second quarter of 2018. Production will continue to ramp up through the first half of 2018. Total production at the Tucker Thermal Project is expected to reach its 30,000 bbls/day design capacity by the end of 2018. In support of this, planned work to de-bottleneck the field and plant infrastructure is expected to be completed in the third quarter of 2018.

Sunrise Energy Project

Average well rates continued to increase with total production averaging 46,800 bbls/day (23,400 bbls/day Husky working interest) during the first quarter of 2018. The project is expected to reach its nameplate capacity of 60,000 bbls/day towards the end of the year.

During the first quarter of 2018, production commenced at the last well pair of the 14 previously drilled well pairs, which were tied in during 2017.

In the first quarter of 2018, two infill wells commenced steaming, and are expected to be on production in the second quarter of 2018. Additionally, seven out of 10 infill wells have been successfully drilled this year and are expected to come online in the fourth quarter of 2018.

In addition, three wells were recompleted in the first quarter of 2018 and were all producing by the end of the quarter. The wells continue to ramp up as planned, each producing above 1,000 bbls/day relative to their previous rates of less than 500 bbls/day.

Western Canada

Oil and Natural Gas Resource Plays

During the first quarter of 2018, production commenced at the remaining six wells of the 16-well 2017 drilling program. Additionally, an 18-well development program in the Spirit River formation, in the Ansell and Kakwa areas, is underway with seven wells drilled in the first quarter of 2018, and four completed.

A drilling program targeting the oil and liquids-rich gas Montney formation in the Karr and Wembley areas is continuing with plans to drill up to eight wells in 2018.

Non-Thermal Developments

The Company is managing the natural decline in Cold Heavy Oil Production with Sand operations with an active optimization program as well as using waterflooding and polymer injection technology.

Asia Pacific

China

Block 29/26

Construction to develop Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project, is scheduled to begin in 2018. First gas production from this seven-well development is expected around the end of 2020. The Company increased its working interest to 75 percent in this field development, from 49 percent, with China National Offshore Oil Corporation ("CNOOC") taking a 25 percent working interest.

Blocks 15/33 and 16/25

The Company began drilling the first of two exploration wells on the shallow water Block 15/33 on March 31, 2018, with the second well expected to follow during the second quarter of 2018. The Company also plans to drill two exploration wells at the nearby exploration Block 16/25 in the second half of 2018. The Company is the operator of both blocks during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Indonesia

Madura Strait

Gross natural gas production for the BD Project averaged 47 mmcf/day (18.6 mmcf/day Husky working interest) and gross NGL production averaged 2,100 bbls/day (1,000 bbls/day Husky working interest) during the first quarter of 2018. The project is expected to ramp up in 2018 towards full sales gas rates, with a gross daily sales target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest).

At the MDA and MBH fields, progress on the construction of the leased floating production unit continued during the first quarter of 2018. Drilling of five MDA field production wells and two MBH field production wells is planned for the second half of 2018, with first gas expected in the 2019 timeframe. The additional MDK shallow water field is expected to be tied in shortly after MDA/MBH startup.

Atlantic

White Rose Field and Satellite Extensions

Project activity continues to ramp up on the West White Rose Project. Construction of the concrete gravity structure is scheduled to begin in the second quarter of 2018 at the purpose-built graving dock in Argentia, Newfoundland and Labrador. First production is expected in 2022.

The Company continues to progress a subsea program to offset natural reservoir declines through infill drilling and workover operations at the White Rose field and satellite extensions. The 2018 subsea program includes infills and workovers in the White Rose Field and the North Amethyst tieback.

In early January 2018, production operations on the *SeaRose* FPSO vessel were suspended for nine days at the direction of the Canada-Newfoundland and Labrador Offshore Petroleum Board. The Company took a number of actions, including organizational changes and improvements to its emergency response procedures and ice management plans. Production at the FPSO has been restored.

Atlantic Exploration

A near field delineation well was spudded in the first quarter of 2018 on an existing significant discovery licence north of the main White Rose field. Husky has a 68.875 percent working interest in the well.

Infrastructure and Marketing

Husky Midstream Limited Partnership ("HMLP")

LLB Direct – Cold Lake Gathering System to Hardisty

During 2017, HMLP commenced the construction of a new 150-kilometre pipeline system in Alberta, which creates additional pipeline capacity to handle the expected growth in the Company's thermal operations in Alberta and Saskatchewan. The construction is currently ahead of schedule and is expected to be completed in 2018.

Saskatchewan Gathering System Expansion

A multi-year expansion program is underway on several fronts and will provide transportation of diluent and heavy oil blend for several additional thermal plants including Rush Lake 2.

Downstream Operations

Downstream operations in the Integrated Corridor include upgrading of heavy crude oil feedstock into synthetic crude oil in Canada ("Upgrading"), refining crude oil in Canada, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining of crude oil in the U.S. to produce and market diesel fuels, gasoline, jet fuel and asphalt 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 are grouped together as the Downstream business segment due to the similar nature of their products and services.

The Company's Downstream operations target three primary objectives: increasing feedstock flexibility to bring the best-priced crude to the Company's refineries, improving flexibility in the range of its products to capitalize on opportunities and enhancing market access to achieve the best returns. The Company's focused integration strategy helps to capture the margin on refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

U.S. Refining and Marketing

Lima Refinery

The crude oil flexibility project is expected to be completed by the end of 2019. The schedule coordinates project work with normal maintenance to provide higher levels of sustained production.

Superior Refinery

A project to increase the heavy oil processing capacity at the Superior Refinery is expected to be completed in the first half of 2018.

2.3 Financial Strategic Plan

In the first quarter of 2018:

- The Company filed a universal short form base shelf prospectus (the "2018 U.S. Shelf Prospectus") with the Alberta Securities Commission and related U.S. registration statement with the SEC containing the 2018 U.S. Shelf Prospectus. The 2018 U.S. Shelf Prospectus replaced the Company's U.S. universal short form base shelf prospectus which expired on January 22, 2018;
- The Board of Directors declared a quarterly dividend of $0.075 per common share, or $75 million, for the fourth quarter of 2017. The dividends were paid on April 2, 2018, to shareholders of record at the close of business on March 20, 2018; and
- Dividends on preferred shares of $9 million declared in the fourth quarter of 2017 were paid. Additionally, dividends of $9 million were declared in the first quarter of 2018, and were paid on April 2, 2018, to shareholders of record at the close of business on March 20, 2018.

3.0 Business Environment

Average Benchmarks

		Three months ended				
Average Benchmarks Summary		**Mar. 31 2018**	Dec. 31 2017	Sept. 30 2017	Jun. 30 2017	Mar. 31 2017
West Texas Intermediate ("WTI") crude oil[1]	*(US$/bbl)*	**62.87**	55.40	48.21	48.29	51.91
Brent crude oil[2]	*(US$/bbl)*	**66.74**	61.39	52.08	49.87	53.78
Light sweet at Edmonton	*($/bbl)*	**72.06**	69.02	56.74	61.92	63.97
Western Canadian Select ("WCS") at Hardisty[3]	*(US$/bbl)*	**38.59**	43.14	38.27	37.16	37.34
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**37.31**	47.97	44.05	43.80	41.62
WTI/Lloyd crude blend differential	*(US$/bbl)*	**23.92**	12.07	9.59	11.05	14.32
Condensate at Edmonton	*(US$/bbl)*	**63.04**	57.97	47.60	48.43	52.27
NYMEX natural gas[4]	*(US$/mmbtu)*	**3.00**	2.93	3.00	3.18	3.32
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.76**	1.85	1.93	2.63	2.79
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**72.96**	73.17	66.40	62.72	62.53
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**81.30**	80.37	69.69	62.08	63.96
Chicago 3:2:1 crack spread	*(US$/bbl)*	**12.84**	20.28	19.30	14.36	11.22
U.S./Canadian dollar exchange rate	*(US$)*	**0.791**	0.786	0.799	0.744	0.756
Canadian $ Equivalents[5]						
WTI crude oil	*($/bbl)*	**79.48**	70.48	60.34	64.91	68.66
Brent crude oil	*($/bbl)*	**84.37**	78.10	65.18	67.03	71.14
WCS at Hardisty	*($/bbl)*	**48.79**	54.89	47.90	49.95	49.39
WTI/Lloyd crude blend differential	*($/bbl)*	**30.24**	15.36	12.00	14.85	18.94
NYMEX natural gas	*($/mmbtu)*	**3.79**	3.73	3.75	4.27	4.39

(1) *Calendar Month Average of settled prices for WTI at Cushing, Oklahoma.*
(2) *Calendar Month Average of settled prices for Dated Brent.*
(3) *WCS 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 WCS at Hardisty, Alberta, set in the month prior to delivery.*
(4) *Prices quoted are average settlement prices during the period.*
(5) *Prices quoted are calculated using U.S. dollar benchmark commodity prices and monthly average U.S./Canadian dollar exchange rates.*

Crude Oil Benchmarks

Global crude oil benchmarks in the first quarter of 2018 increased relative to the first quarter of 2017. WTI averaged US$62.87/bbl during the first quarter of 2018, compared to US$51.91/bbl during the first quarter of 2017. Brent averaged US$66.74/bbl during the first quarter of 2018 compared to US$53.78/bbl during the first quarter of 2017. WCS averaged US$38.59/bbl during the first quarter of 2018, compared to US$37.34/bbl during the first quarter of 2017.

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 by the Company for crude oil production from Atlantic and for NGL production from Asia Pacific is primarily driven by the price of Brent. A portion of the Company's crude oil production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. The Company's crude oil and NGL production was 74 percent heavy crude oil and bitumen in the first quarter of 2018 compared to 69 percent in the first quarter of 2017.

The Company'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. The price of condensate at Edmonton increased in the first quarter of 2018 compared to the first quarter of 2017, primarily due to the increase in light crude oil benchmark pricing.

Natural Gas Benchmarks

The NIT natural gas price benchmark decreased in the first quarter of 2018 compared to the first quarter of 2017, primarily due to the continued oversupply of natural gas in North America.

The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is determined by fixed long-term sales contracts.

North American natural gas is consumed internally by the Company's Upstream and Downstream operations, helping to mitigate the impact of weak natural gas benchmark prices on results.

Refining Benchmarks

The Chicago 3:2:1 crack spread is the key indicator for U.S. refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and 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 or 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 crack spread. The Chicago 3:2:1 crack spread is based on last in first out ("LIFO") accounting, which is a non-GAAP measure (refer to section 10.3).

The cost of the Renewable Fuels Standard legislation has become a material economic factor for refineries in the U.S. The Chicago 3:2:1 crack spread is a gross margin based on the prices of unblended fuels. The cost of purchasing Renewable Identification Numbers ("RINs") or physically blending biofuel into a final gasoline or diesel product has not been deducted from the Chicago 3:2:1 gross margin. The market value of gasoline or distillate that has been blended may be lower than the value of unblended petroleum products given the value a buyer of unblended petroleum can gain by generating a RIN through blending. The Company sells both blended and unblended fuels with the goal of maximizing margins net of RINs purchases.

The Company'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, BP-Husky Toledo and Superior refineries contain approximately 10 to 36 percent of other products that are sold at discounted market prices compared to gasoline and distillate. The Company'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 operations and U.S. dollar denominated debt. The Canadian dollar averaged US$0.791 in the first quarter of 2018 compared to US$0.756 in the first quarter of 2017.

A portion of the Company's long-term sales contracts in Asia Pacific are priced in Chinese Yuan ("RMB"). An increase in the value of RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of natural gas commodities in the region. The Canadian dollar averaged RMB 5.031 in the first quarter of 2018 compared to RMB 5.203 in the first quarter of 2017.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the first quarter of 2018 on earnings before income taxes and net earnings on an annualized basis. The table below reflects what the effect would have been on the financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the first quarter of 2018. 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	2018 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]	**62.87**	*US $1.00/bbl*	**91**	**0.09**	**66**	**0.07**
NYMEX benchmark natural gas price[5]	**3.00**	*US $0.20/mmbtu*	**—**	**—**	**—**	**—**
WTI/Lloyd crude blend differential[6]	**23.92**	*US $1.00/bbl*	**(2)**	**—**	**(1)**	**—**
Canadian asphalt margins	**25.55**	*Cdn $1.00/bbl*	**8**	**0.01**	**6**	**0.01**
Canadian light oil margins	**0.044**	*Cdn $0.005/litre*	**13**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**12.84**	*US $1.00/bbl*	**122**	**0.12**	**95**	**0.09**
Exchange rate (US $ per Cdn $)[3][7]	**0.791**	*US $0.01*	**(59)**	**(0.06)**	**(43)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as at March 31, 2018.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent-based production.*
(5) *Includes impact of natural gas consumption by the Company.*
(6) *Excludes impact on Canadian 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.*

4.0 Results of Operations

4.1 Upstream

Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	Three months ended March 31, **2018**	2017
Gross revenues	**1,084**	1,251
Royalties	**(80)**	(104)
Net revenues	**1,004**	1,147
Production, operating and transportation expenses	**357**	417
Selling, general and administrative expenses	**76**	57
Depletion, depreciation, amortization and impairment ("DD&A")	**447**	547
Exploration and evaluation expenses	**30**	21
Loss (gain) on sale of assets	**(4)**	1
Other – net	**4**	15
Share of equity investment income	**(4)**	(1)
Financial items	**20**	31
Provisions for income taxes	**21**	16
Net earnings	**57**	43

Exploration and Production net revenues decreased by $143 million in the first quarter of 2018 compared to the first quarter of 2017. The decrease is primarily due to lower average realized sales prices and lower production, which is described in more detail below.

Production, operating and transportation expenses decreased by $60 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to dispositions of properties with higher unit operating costs in Western Canada.

DD&A expense decreased by $100 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to lower production and additional heavy oil and bitumen reserve bookings in the fourth quarter of 2017.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended March 31, **2018**	2017
Crude oil and NGL *($/bbl)*		
Light and Medium crude oil	**82.08**	66.70
NGL[(1)]	**55.03**	49.64
Heavy crude oil	**32.80**	41.28
Bitumen	**27.77**	35.20
Total crude oil and NGL average	**40.39**	45.10
Natural gas average *($/mcf)*[(1)]	**7.03**	5.35
Total average *($/boe)*	**40.87**	41.58

(1) *Reported average NGL and natural gas prices include Husky's net working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.*

The average sales prices realized by the Company for crude oil and NGL production decreased by 10 percent in the first quarter of 2018 compared to the same period in 2017. The decrease was primarily due to widening of the light/heavy oil differential combined with a decrease in the Company's light and medium crude oil production and an increase from the Company's thermal bitumen production, resulting in a higher percentage of thermal bitumen production relative to the total crude oil and NGL production.

The average sales prices realized by the Company for natural gas production increased by 31 percent in the first quarter of 2018 compared to the same period in 2017. The increase was primarily due to a higher percentage of fixed priced natural gas production from the Liwan Gas Project and new gas production from the BD Project relative to total natural gas production.

Daily Gross Production

Daily Gross Production	Three months ended March 31, 2018	2017
Crude Oil and NGL *(mbbls/day)*		
Western Canada		
Light and Medium crude oil	**9.1**	14.5
NGL	**11.3**	8.0
Heavy crude oil	**39.7**	48.0
Bitumen[(1)]	**123.2**	120.6
	183.3	191.1
Atlantic		
White Rose and Satellite Fields – light crude oil	**23.1**	34.5
Terra Nova – light crude oil	**5.3**	5.1
	28.4	39.6
Asia Pacific		
Wenchang – light crude oil	**—**	6.6
Liwan and Wenchang – NGL[(2)]	**8.2**	6.2
Madura –NGL[(3)]	**1.0**	—
	9.2	12.8
	220.9	243.5
Natural gas *(mmcf/day)*		
Western Canada	**278.7**	409.8
Asia Pacific		
Liwan[(2)]	**179.7**	133.3
Madura[(3)]	**18.6**	—
	198.3	133.3
	477.0	543.1
Total *(mboe/day)*	**300.4**	334.0

(1) *Bitumen consists of production from thermal developments in Lloydminster, the Tucker Thermal Project located near Cold Lake, Alberta and the Sunrise Energy Project.*
(2) *Reported production volumes include Husky's working interest production from the Liwan Gas Project (49 percent).*
(3) *Reported production volumes include Husky's working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.*

Crude Oil and NGL Production

Crude oil and NGL production decreased by 22.6 mbbls/day in the first quarter of 2018 compared to the first quarter of 2017, primarily due to lower production in Western Canada as a result of the disposition of select legacy assets in 2017 and a reduction of heavy crude oil production in response to the widening of the light/heavy oil differentials, lower production in Atlantic due to a regulatory suspension of production operations on the *SeaRose* FPSO vessel in early 2018, and lower crude oil production in Asia Pacific due to the expiry of the Company's participation in the Wenchang oilfields petroleum contract in late 2017. This was partially offset by increased production from the Company's Sunrise Energy Project and increased NGL production in Western Canada and Asia Pacific.

Natural Gas Production

Natural gas production decreased by 66.1 mmcf/day in the first quarter of 2018 compared to the first quarter of 2017. In Western Canada, natural gas production decreased by 131.1 mmcf/day, primarily due to the disposition of select legacy assets in 2017. In Asia Pacific, natural gas production increased by 65.0 mmcf/day, primarily due to increased gas demand at the Liwan Gas Project and new production from the BD Project.

2018 Production Guidance

The following table shows actual daily production for the three months ended March 31, 2018, and the year ended December 31, 2017, as well as the previously issued production guidance for 2018.

Gross Production	Updated Guidance 2018	Previous Guidance 2018	Actual Production: Three months ended March 31, 2018	Actual Production: Year ended December 31, 2017
Canada				
Light & medium crude oil *(mbbls/day)*	41 - 43	46 - 49	**38**	46
NGL *(mbbls/day)*	10 - 11	10 - 11	**11**	10
Heavy crude oil & bitumen *(mbbls/day)*	168 - 173	174 - 181	**163**	164
Natural gas *(mmcf/day)*	280 - 290	280 - 290	**279**	378
Canada total *(mboe/day)*	266 - 275	277 - 289	**258**	283
Asia Pacific				
Light crude oil *(mbbls/day)*	0 - 0	0 - 0	**—**	5
NGL *(mbbls/day)*[(1)]	10 - 11	10 - 11	**9**	8
Natural gas *(mmcf/day)*[(1)]	200 - 210	200 - 210	**198**	161
Asia Pacific total *(mboe/day)*	43 - 46	43 - 46	**42**	40
Total *(mboe/day)*	310 - 320	320 - 335	**300**	323

(1) Includes Husky's working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.

Annual production guidance for 2018 has been revised lower by 10,000 boe/day and is now expected to average in the range of 310,000 - 320,000 boe/day. In light of wide Canadian heavy oil differentials in the quarter, a decision has been made to reduce heavy oil production and substitute discounted third-party crude as feedstock for the Company's Downstream operations, optimizing the value captured. This includes advancing a turnaround at Tucker Thermal Project into the third quarter of 2018. Also contributing to the production guidance revision is a slower ramp up at the BD Project in Indonesia.

Royalties

Royalty rates as a percentage of gross revenues averaged seven percent in the first quarter of 2018 compared to eight percent in the same period of 2017. Royalty rates in Western Canada averaged nine percent in the first quarter of 2018 compared to eight percent in the same period of 2017. Royalty rates for Atlantic averaged seven percent in the first quarter of 2018 compared to 14 percent in the same period in 2017, primarily due to higher eligible costs. Royalty rates in Asia Pacific averaged six percent in both the first quarter of 2018 and of 2017.

Operating Costs

Operating Costs *($ millions)*	Three months ended March 31, **2018**	Three months ended March 31, 2017
Western Canada	**295**	340
Atlantic	**45**	52
Asia Pacific[(1)]	**19**	19
Total	**359**	411
Per unit operating costs *($/boe)*	**13.33**	13.75

(1) Reported operating costs include Husky's working interest from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.

Total Exploration and Production operating costs were $359 million in the first quarter of 2018 compared to $411 million in the same period in 2017. Total per unit operating costs averaged $13.33/boe in the first quarter of 2018 compared to $13.75/boe in the same period in 2017 with the decrease primarily due to dispositions of properties in Western Canada with higher per unit operating costs.

Per unit operating costs in Western Canada averaged $14.35/boe in the first quarter of 2018 compared to $14.64/boe in the same period in 2017. The decrease in per unit operating costs was primarily due to the same factors which impacted total per unit operating costs.

Per unit operating costs in Atlantic averaged $17.51/bbl in the first quarter of 2018 compared to $14.64/bbl in the same period in 2017. The increase in per unit operating costs was primarily due to lower production as a result of a regulatory suspension of production operations on the *SeaRose* FPSO vessel in early 2018.

Per unit operating costs in Asia Pacific averaged $5.02/boe in the first quarter of 2018 compared to $5.96/boe in the same period in 2017. The decrease in per unit operating costs was primarily due to higher production at the Liwan Gas Project.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses	Three months ended March 31,	
($ millions)	**2018**	2017
Seismic, geological and geophysical	**28**	19
Expensed land	**2**	2
Total	**30**	21

Exploration and Evaluation expenses in the first quarter of 2018 were $30 million compared to $21 million in the same period in 2017. The increase was primarily due to the acquisition of seismic data in Western Canada.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in the first quarter of 2018 compared to the first quarter of 2017 reflecting increased investment in thermal developments, Atlantic and Western Canada. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1]	Three months ended March 31,	
($ millions)	**2018**	2017
Exploration		
Western Canada	**25**	9
Thermal developments	**1**	—
Atlantic	**3**	62
Asia Pacific[2]	**11**	2
	40	73
Development		
Western Canada	**91**	30
Thermal developments	**152**	118
Non-thermal developments	**15**	11
Atlantic	**175**	43
Asia Pacific[2]	**4**	4
	437	206
Acquisitions		
Western Canada	**4**	10
Thermal developments	**38**	—
	42	10
Total	**519**	289

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

Western Canada

During the first three months of 2018, $120 million (23 percent) was invested in Western Canada, compared to $49 million (17 percent) in the same period in 2017. Capital expenditures in 2018 related primarily to resource play development targeting the Spirit River formation in the Ansell and Kakwa areas and the Montney formation in the Karr and Wembley areas.

Thermal Developments

During the first three months of 2018, $191 million (37 percent) was invested in thermal developments compared to $118 million (41 percent) in the same period in 2017. Capital expenditures in 2018 related primarily to the development of the Lloyd thermal bitumen projects.

Non-Thermal Developments

During the first three months of 2018, $15 million (three percent) was invested in non-thermal developments compared to $11 million (four percent) in the same period in 2017. Capital expenditures in 2018 related primarily to sustainment activities.

Atlantic

During the first three months of 2018, $178 million (34 percent) was invested in Atlantic compared to $105 million (36 percent) in the same period in 2017. Capital expenditures in 2018 related primarily to development of the West White Rose Project and sustainment and development activities at the White Rose field and satellite extensions.

Asia Pacific

During the first three months of 2018, $15 million (three percent) was invested in Asia Pacific compared to $6 million (two percent) in the same period in 2017. Capital expenditures in 2018 related primarily to the exploration of Block 15/33.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled during the three months ended March 31, 2018 and 2017:

	Three months ended March 31,			
	2018		2017	
Wells Drilled *(wells)*[1]	**Gross**	**Net**	Gross	Net
Thermal developments	**17**	**16**	9	9
Non-thermal developments	**4**	**4**	—	—
Western Canada	**11**	**10**	10	9
Total	**32**	**30**	19	18

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*

Offshore drilling activity

The following table discloses the Company's drilling activity during the three months ended March 31, 2018:

Region	Well	Working Interest	Well Type
Atlantic	North Amethyst G-25 11	68.875 percent	Development

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary	Three months ended March 31,	
($ millions)	**2018**	2017
Gross revenues	**446**	333
Purchases of crude oil and products	**421**	295
Infrastructure gross margin	**25**	38
Marketing and other	**165**	36
Total Infrastructure and Marketing gross margin	**190**	74
Production, operating and transportation expenses	**2**	3
Selling, general and administrative expenses	**1**	1
Loss on sale of assets	**—**	1
Other – net	**2**	(3)
Share of equity investment income	**(5)**	(24)
Provisions for income taxes	**52**	26
Net earnings	**138**	70

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $113 million and $126 million, respectively, in the first quarter of 2018 compared to the first quarter of 2017, primarily due to increased volumes and prices.

Marketing and other increased by $129 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to crude oil marketing gains from widening price differentials between Canada and the U.S., which the Company is able to capture due to its committed capacity on the Keystone pipeline.

4.2 Downstream

Upgrading

Upgrading Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2018**	2017
Gross revenues	**465**	384
Purchases of crude oil and products	**239**	248
Gross margin	**226**	136
Production, operating and transportation expenses	**46**	49
Selling, general and administrative expenses	**2**	2
Depletion, depreciation, amortization and impairment	**28**	19
Provisions for income taxes	**41**	18
Net earnings	**109**	48
Upgrader throughput *(mbbls/day)*[(1)]	**81.0**	77.9
Total sales *(mbbls/day)*	**79.4**	76.2
Synthetic crude oil sales *(mbbls/day)*	**56.0**	54.1
Upgrading differential *($/bbl)*	**32.31**	20.88
Unit margin *($/bbl)*	**31.63**	19.83
Unit operating cost *($/bbl)*[(2)]	**6.31**	6.99

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

Gross revenues increased by $81 million in the first quarter of 2018 compared to the same period in the first quarter of 2017, primarily due to higher realized prices for synthetic crude oil and higher sales volumes. The price of Husky Synthetic Blend in the the first quarter of 2018 averaged $77.19/bbl compared to $67.53/bbl in the first quarter of 2017.

Gross margin increased by $90 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to the widening of the light/heavy oil differentials. The upgrading differential averaged $32.31/bbl in the first quarter of 2018, an increase of $11.43/bbl or 55 percent, compared to the same period in 2017. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	Three months ended March 31, **2018**	 2017
Gross revenues	**721**	568
Purchases of crude oil and products	**578**	445
Gross margin		
Fuel	**29**	28
Refining	**49**	42
Asphalt	**53**	40
Ancillary	**12**	13
	143	123
Production, operating and transportation expenses	**60**	60
Selling, general and administrative expenses	**13**	11
Depletion, depreciation, amortization and impairment	**29**	29
Financial items	**3**	3
Provisions for income taxes	**10**	5
Net earnings	**28**	15
Number of fuel outlets[1]	**558**	480
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.4**	6.4
Fuel sales per retail outlet *(thousands of litres/day)*	**11.9**	11.5
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**12.0**	11.8
Lloydminster Refinery *(mbbls/day)*	**28.7**	28.0
Ethanol production *(thousands of litres/day)*	**831.5**	839.6

[1] *Average number of fuel outlets for period indicated.*

Canadian Refined Products gross revenues increased by $153 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to higher product prices and higher sales volumes.

Canadian Refined Products purchases of crude oil and products increased by $133 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to higher commodity prices and higher throughput volumes.

U.S. Refining and Marketing

U.S. Refining and Marketing Loss Summary	Three months ended March 31,	
($ millions, except where indicated)	**2018**	2017
Gross revenues[1]	**2,771**	2,173
Purchases of crude oil and products[1]	**2,505**	1,973
Gross margin	**266**	200
Production, operating and transportation expenses	**163**	140
Selling, general and administrative expenses	**5**	4
Depletion, depreciation, amortization and impairment	**94**	89
Other – net	**6**	(3)
Financial items	**4**	3
Recovery of income taxes	**(1)**	(12)
Net loss	**(5)**	(21)
Select operating data:		
Lima Refinery throughput *(mbbls/day)*[2]	**164.4**	172.0
BP-Husky Toledo Refinery throughput *(mbbls/day)*[2]	**75.0**	77.0
Superior Refinery throughput *(mbbls/day)*[2]	**37.0**	—
Refining and marketing margin *(US$/bbl crude throughput)*[3]	**8.51**	7.08
Refinery inventory *(mmbbls)*[4]	**9.7**	8.6

(1) During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.
(2) Includes all crude oil, feedstock, intermediate feedstock and blend-stocks used in producing sales volumes from the refinery.
(3) Prior period has been restated to include impact of U.S. product marketing margin.
(4) Feedstock and refined products are included in refinery inventory.

U.S. Refining and Marketing gross revenues increased by $598 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to an increase in sales volume resulting from the acquisition of the Superior Refinery in late 2017, and higher refined product prices in the first quarter of 2018.

U.S. Refining and Marketing purchases of crude oil and products increased by $532 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to higher throughput volumes due to the addition of the Superior Refinery and higher commodity prices in the first quarter of 2018.

Production, operating and transportation expenses increased by $23 million in the first quarter of 2018 compared to the first quarter of 2017, primarily due to the acquisition of the Superior Refinery in late 2017.

The Chicago 3:2:1 crack spread is based on 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 impact of FIFO accounting was an increase in net earnings of approximately $11 million in the first quarter of 2018 compared to an increase in net earnings of approximately $7 million in the first quarter of 2017.

Downstream Capital Expenditures

In the first three months of 2018, Downstream capital expenditures totalled $77 million compared to $83 million in the same period in 2017. In Canada, capital expenditures of $22 million related primarily to reliability and environmental initiatives at the Lloydminster Upgrader. In the U.S., capital expenditures of $55 million were primarily due to the crude oil flexibility project at the Lima Refinery, turnaround preparations at the Superior and Lima refineries, and various reliability and environmental initiatives at the Lima and BP-Husky Toledo refineries.

4.3 Corporate

Corporate Summary *($ millions) income (expense)*	Three months ended March 31, **2018**	 2017
Selling, general and administrative expenses	**(72)**	(59)
Depletion, depreciation and amortization	**(20)**	(16)
Net foreign exchange gain (loss)	**22**	(2)
Finance income	**11**	5
Finance expense	**(48)**	(55)
Recovery of income taxes	**28**	43
Net loss	**(79)**	(84)

The Corporate segment reported a net loss of $79 million in the first quarter of 2018 compared to a net loss of $84 million in the first quarter of 2017. The net foreign exchange gain increased by $24 million due to items noted below.

Foreign Exchange Summary *($ millions, except where indicated)*	Three months ended March 31, **2018**	 2017
Non-cash working capital gain (loss)	**2**	(19)
Other foreign exchange gain	**20**	17
Net foreign exchange gain (loss)	**22**	(2)
U.S./Canadian dollar exchange rates:		
At beginning of period	**US$0.799**	US$0.745
At end of period	**US$0.775**	US$0.751

Included in the other foreign exchange gain (loss) are realized and unrealized 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 with the goal of minimizing the impact of foreign exchange gains and losses on the condensed interim consolidated financial statements.

Consolidated Income Taxes

Consolidated Income Taxes *($ millions)*	Three months ended March 31, **2018**	 2017
Provisions for income taxes	**95**	10
Cash income taxes paid	**23**	21

Consolidated income taxes were a provision of $95 million in the first quarter of 2018 compared to a provision of $10 million in the first quarter of 2017. The increase in consolidated income taxes was primarily due to the increase in earnings before tax in the first quarter of 2018 compared to the same period in 2017.

5.0 Risk Management and Financial Risks

5.1 Risk Management

The Company is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's Annual Information Form dated March 1, 2018. The Company has processes in place designed to identify the principal risks of the business and has put in place what it believes is appropriate mitigation to manage such risks where possible. The Company's operational, political, environmental, financial, liquidity and contract and credit risks have not materially changed since December 31, 2017, which were discussed in the Company's MD&A for the year ended December 31, 2017.

5.2 Financial Risks

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

Commodity Price Risk Management
The Company uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production, and it also uses 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 long-term liabilities. All derivatives are measured at fair value through profit or loss other than non-financial derivative contracts that meet the Company's own use requirements.

At March 31, 2018,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. Refer to Note 14 of the condensed interim consolidated financial statements.

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.

Foreign Currency Risk Management
At March 31, 2018, Cdn $3.5 billion or 65 percent of the Company'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.

For the three months ended March 31, 2018, the Company incurred an unrealized loss of $89 million, arising from the translation of the debt, net of tax recovery of $14 million, which was recorded in hedge of net investment within other comprehensive income ("OCI").

6.0 Liquidity and Capital Resources

6.1 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include funds 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 believes that it has sufficient liquidity to sustain its operations, fund capital programs and meet non-cancellable contractual obligations and commitments in the short and long-term principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of debt, borrowings under committed and uncommitted credit facilities and cash proceeds from asset sales. 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, 2018, the Company had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)]	**850**	**409**
Syndicated credit facilities[(2)]	**4,000**	**3,800**
Total	**4,850**	**4,209**

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

At March 31, 2018, the Company had $4,209 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $409 million are short-term uncommitted credit facilities. A total of $441 million short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of long-term committed borrowing credit facilities was used in support of commercial paper. At March 31, 2018, the Company had no direct borrowing against committed credit facilities. The maturity dates for the Company's revolving syndicated credit facilities are March 9, 2020 and June 19, 2022, respectively. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade credit 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.

The Company's share capital is not subject to external restrictions. The Company's leverage covenant under both of its revolving syndicated credit facilities is debt to capital and calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. 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 was in compliance with the syndicated credit facility covenants at March 31, 2018, and assessed the risk of noncompliance to be low.

Working capital is the amount by which current assets exceed current liabilities. At March 31, 2018, working capital was $2,336 million compared to $2,109 million at December 31, 2017.

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, 2018.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019. The 2017 Canadian Shelf Prospectus replaced the Company's Canadian universal short form base shelf prospectus which expired on March 23, 2017. During the 25-month period that the 2017 Canadian Shelf Prospectus is in effect, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On January 29, 2018, the Company filed the 2018 U.S. Shelf Prospectus with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement with the SEC containing the 2018 U.S. Shelf Prospectus became effective which enables the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. up to and including February 29, 2020. The 2018 U.S. Shelf Prospectus replaced the Company's U.S universal short form base shelf prospectus which expired on January 22, 2018. During the 25-month period that the 2018 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.

As at March 31, 2018, the Company has $3.0 billion in unused capacity under the 2017 Canadian Shelf Prospectus and US$3.0 billion in unused capacity under the 2018 U.S. Shelf Prospectus and related U.S. registration statement. The ability of the Company to utilize the capacity under the 2017 Canadian Shelf Prospectus and 2018 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 *($ millions)*	**March 31, 2018** **Outstanding**
Total debt[1]	**5,543**
Shareholders' equity	**18,323**

[1] *Total debt is defined as 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 totalled $23.9 billion as at March 31, 2018 (December 31, 2017 – $23.4 billion). To maintain or adjust the capital structure, the Company may, from time to time, sell assets, 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 funds from operations (refer to Section 10.3). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At March 31, 2018, debt to capital employed was 23.2 percent (December 31, 2017 – 23.2 percent) and debt to funds from operations was 1.6 times (December 31, 2017 – 1.6 times), within the Company's targets.

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.

6.3 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

In the normal course of business, the Company is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to the Company's MD&A for the year ended December 31, 2017 under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2017. During the three months ended March 31, 2018, 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 performs management services as the operator of the assets held by HMLP for which it earns a management fee. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to PAH and CKI, which are affiliates of one of the Company's principal shareholders. For the three months ended March 31, 2018, the Company charged HMLP $62 million related to construction and management services. For the three months ended March 31, 2018, the Company had purchases from HMLP of $49 million related to the use of the pipeline for the Company's blending activities, transportation and storage activities. As at March 31, 2018, the Company had $37 million due from HMLP.

The Company sells natural gas to, and purchases steam from, 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, which equates to fair value. 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. For the three months ended March 31, 2018, the amount of natural gas sales to Meridian totalled $9 million. For the three months ended March 31, 2018, the amount of steam purchased by the Company from Meridian totalled $4 million. For the three months ended March 31, 2018, the total cost recovery by the Company for facilities services was $4 million. At March 31, 2018, the Company had $3 million due from Meridian with respect to these transactions.

7.0 Critical Accounting Estimates and Key Judgments

The application of some of the Company's accounting policies requires subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in the Company's MD&A for the year ended December 31, 2017, as well as critical areas of judgment 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.

8.0 Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the Consolidated Statements of Income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. 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 implementation of IFRS 16 consists of four phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 16 to stakeholders, and creating a project steering committee.
- Scoping – This phase focuses on identifying and categorizing the Company's contracts, performing a high-level impact assessment and determining the adoption approach and which optional recognition exemptions will be applied by the Company. This phase also includes identifying the systems impacted by the new accounting standard and evaluating potential system solutions.
- Detailed analysis and solution development – This phase includes assessing which agreements contain leases and determining the expected conversion differences for leases currently accounted for as operating leases under the existing standard. This phase also includes selection of the system solution.
- Implementation – This phase includes implementing the changes required for compliance with IFRS 16. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 16.

The Company is currently in the detailed analysis and solution development phase of implementing IFRS 16. The impact on the Company's consolidated financial statements upon adoption of IFRS 16 is currently being assessed.

Changes in Accounting Policies

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15 Revenue from Contracts with Customers, deferring the effective date to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 15 did not require any material adjustments to the amounts recorded in the consolidated financial statements; however, additional disclosures are presented in the interim consolidated financial statements.

Revenue is recognized when the performance obligations are satisfied and revenue can be reliably measured. Revenue is measured at the consideration specified in the contracts and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Natural gas sales in the Asia Pacific region are under long term, fixed price contracts. Substantially all other revenue is based on floating prices. Performance obligations associated with the sale of crude oil, crude oil equivalents, and refined products are satisfied at the point in time when the products are delivered to and title passes to the customer. Performance obligations associated with processing services, transportation, blending and storage, and marketing services are satisfied at the point in time when the services are provided.

Financial Instruments

In July 2014, the IASB issued IFRS 9 Financial Instruments to replace IAS 39, which provides a single model for classification and measurement based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial instruments. For financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in a more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard was effective for annual periods beginning on January 1, 2018. The Company retrospectively adopted the standard on January 1, 2018. The adoption of IFRS 9 did not require any material adjustments to the consolidated financial statements.

Financial assets previously classified as loans and receivables (cash and cash equivalents, accounts receivable, restricted cash, and long-term receivables), as well as financial liabilities previously classified as other financial liabilities (accounts payable and accrued liabilities, short-term debt, and long-term debt) have been reclassified to amortized cost. The carrying value and measurement of all financial instruments remains unchanged. The Company's current process for assessing short-term receivables lifetime expected credit losses collectively in groups that share similar credit risk characteristics is unadjusted with the adoption of the new impairment model and resulted in no additional impairment allowance. Additionally, long-term receivables were assessed individually under the expected credit loss model and no impairment was concluded.

Amendments to IFRS 2 Share-based payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018. The amendments clarify how to account for certain types of share-based payment arrangements. The adoption of the amendments did not have a material impact on the Company's consolidated financial statements.

9.0 Outstanding Share Data

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: April 23, 2018:

• common shares	1,005,121,098
• 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	22,666,513
• stock options exercisable	11,533,437

10.0 Reader Advisories

10.1 Forward-Looking Statements

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", "is 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 2018 production guidance, including guidance for specified areas and product types; and the Company's objective of maintaining stated debt to capital employed and debt to funds from operations ratio targets;

- with respect to the Company's thermal developments: Lloyd thermal bitumen production expectations over the next three years; the design capacity for, and the expected timing of first production at, the Rush Lake 2 thermal development; the expected timing of commencement of construction on the CPF at Dee Valley; the expected timing of first production at Dee Valley, Spruce Lake North and Spruce Lake Central; the expected timing of first production from, and design capacity of, two new Lloyd thermal projects; the expected timing of sanction of two new Lloyd thermal projects; the expected timing of the remaining five wells coming on production at the Tucker Thermal Project; total production expectations for 2018, and the expected timing of completion of work to de-bottleneck the field and plant infrastructure, at the Tucker Thermal Project; the expected timing to reach nameplate capacity at the Sunrise Energy Project and expected timing that infill wells at Sunrise will come online and start production;

- with respect to the Company's Western Canada resource plays, 2018 drilling plans in the Karr and Wembley areas;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of construction at, and first production from, Liuhua 29-1; drilling plans at Block 15/33 and Block 16/25 offshore China; the expected timing of ramp-up towards full sales gas rates at the BD Project; the expected timing of drilling of five MDA field production wells and two MBH field production wells, and the expected timing of first gas therefrom; and the expected timing of tie-in of the additional MDK shallow water field;

- with respect to the Company's Offshore business in Atlantic: the expected timing of commencement of construction of the concrete gravity structure, and the expected timing of first production, at the West White Rose Project; and targeted production at the White Rose Field and satellite extensions;

- with respect to the Company's Infrastructure and Marketing business, the expected timing of completion of construction of HMLP's new 150-kilometre pipeline system; and

- with respect to the Company's Downstream operating segment: the expected timing of completion of the crude oil flexibility project at the Lima Refinery; and the expected timing of completion of a project to increase the heavy oil processing capacity at the Superior 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, including the timing of regulatory approvals, 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 and regulators, among others.

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 the Company.

The Company's Annual Information Form for the year ended December 31, 2017 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.

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 management's assessment of the future considering all information available to it at the relevant time. 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.

10.2 Cautionary Note Required by National Instrument 51-101

Unless otherwise noted, historical production volumes provided represent the Company's working interest share before royalties.

The Company uses the term "barrels of oil equivalent" (or "boe"), which is consistent with other oil and gas companies' 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 but does not represent value equivalency at the wellhead.

10.3 Non-GAAP Measures

Disclosure of non-GAAP Measures

The Company uses measures primarily based on IFRS and also uses some secondary non-GAAP measures. The non-GAAP measures included in this MD&A and related disclosures are: adjusted net earnings (loss), funds from operations, debt to capital employed, debt to funds from operations and LIFO. None of these measures are used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for debt to capital employed or debt to funds from operations. These are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. The non-GAAP measures 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 used in this MD&A and related disclosures are defined below.

Adjusted Net Earnings (Loss)

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 (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets which are not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing the Company's financial performance through providing comparability between periods.

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the three months ended:

Adjusted Net Earnings (Loss)	Three months ended							
	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30
($ millions)	**2018**	2017	2017	2017	2017	2016	2016	2016
Net earnings (loss)	**248**	672	136	(93)	71	186	1,390	(196)
Impairment (impairment reversal) of property, plant and equipment, net of tax	**—**	3	—	123	—	(202)	—	12
Exploration and evaluation asset write-downs, net of tax	**—**	—	1	3	—	41	—	22
Inventory write-downs, net of tax	**—**	—	—	—	—	6	—	—
Loss/(gain) on sale of assets, net of tax	**(3)**	(10)	(1)	(23)	2	(37)	(1,490)	71
Adjusted net earnings (loss)	**245**	665	136	10	73	(6)	(100)	(91)

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 measure assists management and investors in evaluating the Company's financial strength.

Debt to Funds from Operations

Debt to funds from operations 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 funds from operations. Funds from operations is equal to cash flow – operating activities plus change in non-cash working capital. Management believes this measure assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of debt to funds from operations for the periods ended March 31, 2018, and December 31, 2017:

Debt to Funds from Operations *($ millions)*	**March 31, 2018**	December 31, 2017
Total debt	**5,543**	5,440
Funds from operations[1]	**3,540**	3,306
Debt to funds from operations	**1.6**	1.6

[1] *Annualized using 12 - month rolling figures.*

Funds from Operations

Funds 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. Funds from operations is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Funds from operations equals cash flow – operating activities plus change in non-cash working capital.

Funds from operations has been restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

The following table shows the reconciliation of net earnings (loss) to funds from operations and related per share amounts for the months ended:

Funds from Operations	Three months ended							
	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30
($ millions)	**2018**	2017	2017	2017	2017	2016	2016	2016
Net earnings (loss)	**248**	672	136	(93)	71	186	1,390	(196)
Items not affecting cash:								
Accretion	**24**	28	27	29	28	30	29	33
Depletion, depreciation, amortization and impairment	**618**	647	673	862	700	405	638	697
Inventory write-down to net realizable value	**—**	—	—	—	—	9	—	—
Exploration and evaluation expenses	**—**	—	1	4	1	56	—	30
Deferred income taxes	**77**	(360)	52	(57)	6	45	99	(108)
Foreign exchange loss (gain)	**1**	1	(3)	15	(17)	(29)	12	12
Stock-based compensation	**21**	25	11	8	1	3	5	8
Loss/(gain) on sale of assets	**(4)**	(13)	(2)	(33)	2	(52)	(1,680)	96
Unrealized mark to market loss (gain)	**(86)**	57	31	18	(50)	26	(28)	(83)
Share of equity investment loss (income)	**(9)**	(1)	(12)	(23)	(25)	(38)	21	1
Other	**2**	8	9	5	(6)	29	(2)	(2)
Settlement of asset retirement obligations	**(49)**	(45)	(23)	(20)	(48)	(31)	(11)	(23)
Deferred revenue	**(20)**	(5)	(9)	—	(2)	23	146	40
Distribution from joint ventures	**72**	25	—	—	—	—	—	—
Change in non-cash working capital	**(366)**	337	3	98	(40)	(18)	124	(43)
Cash flow – operating activities	**529**	1,376	894	813	621	644	743	462
Change in non-cash working capital	**366**	(337)	(3)	(98)	40	18	(124)	43
Funds from operations	**895**	1,039	891	715	661	662	619	505
Funds from operations – basic	**0.89**	1.03	0.89	0.71	0.66	0.66	0.62	0.50
Funds from operations – diluted	**0.89**	1.03	0.89	0.71	0.66	0.66	0.62	0.50

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 in previous months. 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.

10.4 Additional 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 the Company's MD&A for the year ended December 31, 2017, the 2017 consolidated financial statements, the Annual Information Form dated March 1, 2018 filed with Canadian securities regulatory authorities and the 2017 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, 2018 are compared to the results for the three months ended March 31, 2017. Discussions with respect to the Company's financial position as at March 31, 2018 are compared to its financial position as at December 31, 2017. 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 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, 2018 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Terms

Adjusted Net Earnings (Loss)	*Net earnings (loss) before after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on the sale of assets*
Asia Pacific	*Includes Upstream oil and gas exploration and production activities located offshore China and Indonesia*
Atlantic	*Includes Upstream oil and gas exploration and production activities located offshore Newfoundland and Labrador*
Bitumen	*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*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to Funds from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by funds 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*
Feedstock	*Raw materials which are processed into petroleum products*
Funds from Operations	*Cash flow – operating activities plus change in non-cash working capital*
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*
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*
Net Revenue	*Gross revenue less royalties*
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 sands	*Sands and other rock materials that contain crude bitumen and include all other associated mineral substances*
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, contributed surplus, retained earnings, accumulated other comprehensive income and non-controlling interest*
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*
Thermal	*Use of steam injection into the reservoir in order to enable heavy oil and bitumen to flow to the well bore*
Total Debt	*Long-term debt, including long-term debt due within one year, and short-term debt*
Turnaround	*Performance of scheduled plant or facility maintenance requiring the complete or partial shutdown of the plant or facility operations*
Western Canada	*Includes Upstream oil and gas exploration and development activities located in Alberta, Saskatchewan and British Columbia*

Units of Measure

bbls	*barrels*
bbls/day	*barrels per day*
bcf	*billion cubic feet*
boe	*barrels of oil equivalent*
boe/day	*barrels of oil equivalent per day*
GJ	*gigajoule*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mcf	*thousand cubic feet*
mcfge	*million cubic feet of gas equivalent*
mmbbls	*million barrels*
mmboe	*million barrels of oil equivalent*
mmbtu	*million British Thermal Units*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
m3	*cubic meter*