MANAGEMENT'S DISCUSSION AND ANALYSIS

July 21, 2017

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Jun. 30**	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30
($ millions, except where indicated)	**2017**	2017	2016	2016	2016	2016	2015	2015
Production *(mboe/day)*	**319.5**	334.0	327.0	301.0	315.8	341.3	357.0	333.0
Gross revenues and marketing and other	**4,616**	4,615	3,865	3,520	3,261	2,578	3,903	4,286
Net earnings (loss)	**(93)**	71	186	1,390	(196)	(458)	(69)	(4,092)
Per share – Basic	**(0.10)**	0.06	0.19	1.37	(0.20)	(0.47)	(0.08)	(4.17)
Per share – Diluted	**(0.10)**	0.06	0.19	1.37	(0.20)	(0.47)	(0.09)	(4.19)
Adjusted net earnings (loss)(1)	**10**	71	(6)	(100)	(91)	(458)	(53)	(101)
Funds from operations(1)	**715**	661	662	619	505	412	635	682
Per share – Basic	**0.71**	0.66	0.66	0.62	0.50	0.41	0.65	0.69
Per share – Diluted	**0.71**	0.66	0.66	0.62	0.50	0.41	0.65	0.69

(1) *Adjusted net earnings (loss) and funds from operations are non-GAAP measures. The calculation of funds from operations has changed from prior periods. Prior periods have been restated to conform to current presentation. Refer to Section 11 for a reconciliation to the GAAP measures and an explanation of the changes.*

Performance

- Net loss of $93 million in the second quarter of 2017 compared to a net loss of $196 million in the second quarter of 2016 with the improvement primarily due to:
  - Higher Upstream North American commodity prices;
  - Increased production from the Company's thermal developments; and
  - Increased natural gas and natural gas liquids (“NGLs“) production from the Liwan Gas Project in Asia Pacific.

  Partially offset by:
  - A recognition of a pre-tax impairment charge of $168 million in the second quarter of 2017;
  - Lower realized U.S. refining margins; and
  - Lower Canadian upgrading and refining throughput and sales volumes due to major planned turnarounds at the Lloydminster Upgrader and Lloydminster asphalt refinery.
- Funds from operations of $715 million in the second quarter of 2017 compared to $505 million in the second quarter of 2016 with the increase attributed to the same factors noted above for net loss.
- Production increased by 3.7 mboe/day or one percent to 319.5 mboe/day in the second quarter of 2017 compared to the second quarter of 2016 as a result of:
  - Increased production from thermal developments; and
  - Increased natural gas and NGLs production from the Liwan Gas Project in Asia Pacific.

  Partially offset by:
  - Decreased production from Western Canada mainly due to the disposition of select legacy assets in 2016 and 2017.

Key Projects

- Development continues at the 10,000 bbls/day Rush Lake 2 thermal project. Construction of the central processing facility is progressing to schedule and drilling of the Steam Assisted Gravity Drainage ("SAGD") injector-producer well pairs will commence in the third quarter of 2017. First production is expected in the first half of 2019.
- At the Tucker Thermal Project, drilling of a new 15-well pad was completed in the second quarter. Production from this new pad is expected to ramp up through the first half of 2018, with total production at the Tucker Thermal Project expected to grow towards its 30,000 bbls/day design capacity by the end of 2018.
- The liquids-rich BD Gas Project in the Madura Strait began testing and commissioning in the second quarter and is expected to reach commercial production soon. Gas is being provided to the East Java market. The project is expected to ramp up throughout 2017 towards full sales gas rate, 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 NGLs (2,400 bbls/day Husky working interest).
- Construction of the shallow water platforms for the MDA-MBH fields has been completed and the platforms have been installed. Tendering for a floating production unit has been completed and a contract is in progress. First gas is expected in the 2019-2020 timeframe, with the additional MDK shallow water field expected to be tied in during the same period.
- The Company and its partners have announced plans to move ahead with the West White Rose project. The project will be developed using a fixed drilling platform, which has received regulatory approval.
- In May 2017, the Company announced a new discovery at Northwest White Rose. The White Rose A-78 well was drilled approximately 11 kilometres northwest of the SeaRose floating production, storage and offloading ("FPSO") vessel in the first quarter of 2017 and delineated a light oil column of more than 100 metres (gross). Evaluation of results is ongoing. The Company has a 93.23% working interest in the well.
- The Company is advancing a 16-well development drilling program targeting the Wilrich formation in the Ansell and Kakwa areas.
- Progress continues to be made on the implementation of a single expanded truck transport network of approximately 160 sites. The consolidation of the two networks is expected in the second half of 2017.
- The Company continued work on a crude oil flexibility project at the Lima Refinery. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada, providing the ability to swing between light and heavy crude oil feedstock. The full scope of the project is expected to be completed around the end of 2018.
- Front-end engineering and design (“FEED“) work continued on a potential 30,000 bbls/day expansion of the Company's asphalt processing capacity in Lloydminster with a final investment decision expected in 2018.

Divestitures

- During the second quarter of 2017, the Company completed the sale of select assets in Western Canada to third parties, representing approximately 2,600 boe/day for gross proceeds of approximately $123 million, resulting in a pre-tax gain of $34 million.

Financial

- Dividends on preferred shares of $9 million were declared and paid in the second quarter of 2017.

2. Business Environment

Average Benchmarks

Average Benchmarks Summary		Three months ended Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sept. 30, 2016	Jun. 30, 2016	Six months ended Jun. 30, 2017	Jun. 30, 2016
West Texas Intermediate ("WTI") crude oil(1)	*(U.S. $/bbl)*	**48.29**	51.91	49.29	44.94	45.59	**50.10**	39.52
Brent crude oil(2)	*(U.S. $/bbl)*	**49.87**	53.78	49.47	45.85	45.57	**51.82**	39.73
Light sweet at Edmonton	*($/bbl)*	**61.92**	63.97	61.60	54.80	54.78	**62.95**	47.79
Daqing(3)	*(U.S. $/bbl)*	**47.35**	51.71	47.90	42.19	43.18	**49.53**	36.67
Western Canadian Select at Hardisty(4)	*(U.S. $/bbl)*	**37.16**	37.34	34.97	31.44	32.29	**37.25**	25.75
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**43.80**	41.62	40.05	36.10	35.81	**42.71**	27.15
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**11.05**	14.32	14.19	13.42	13.17	**12.69**	13.60
Condensate at Edmonton	*(U.S. $/bbl)*	**48.43**	52.27	48.33	43.07	44.07	**50.35**	39.24
NYMEX natural gas(5)	*(U.S. $/ mmbtu)*	**3.18**	3.32	2.98	2.81	1.95	**3.25**	2.02
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**2.63**	2.79	2.67	2.09	1.18	**2.71**	1.59
Chicago Regular Unleaded Gasoline	*(U.S. $/bbl)*	**62.72**	62.53	59.07	58.90	63.80	**62.63**	53.10
Chicago Ultra-low Sulphur Diesel	*(U.S. $/bbl)*	**62.08**	63.96	61.49	59.88	59.34	**63.01**	52.25
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**14.36**	11.22	10.59	14.29	16.67	**12.80**	13.04
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.744**	0.756	0.750	0.766	0.776	**0.750**	0.752
Canadian $ Equivalents(6)								
WTI crude oil	*($/bbl)*	**64.91**	68.66	65.72	58.67	58.75	**66.80**	52.55
Brent crude oil	*($/bbl)*	**67.03**	71.14	65.96	59.86	58.72	**69.09**	52.83
Daqing	*($/bbl)*	**63.64**	68.40	63.87	55.08	55.64	**66.04**	48.76
Western Canadian Select at Hardisty	*($/bbl)*	**49.95**	49.39	46.63	41.04	41.61	**49.67**	34.24
WTI/Lloyd crude blend differential	*($/bbl)*	**14.85**	18.94	18.92	17.52	16.97	**16.92**	18.09
NYMEX natural gas	*($/mmbtu)*	**4.27**	4.39	3.97	3.67	2.51	**4.33**	2.69

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

Crude Oil Benchmarks

Global crude oil benchmarks fell in the second quarter of 2017, compared to the first quarter, despite certain members of the Organization of Petroleum Exporting Countries ("OPEC") and non-members reducing crude oil output in 2017. This OPEC cut was partially offset by increased production from OPEC members not bound to the production restrictions and increases observed from U.S shale fields. WTI averaged U.S. $48.29/bbl during the second quarter of 2017, compared to U.S. $45.59/bbl during the second quarter of 2016. Brent averaged U.S. $49.87/bbl during the second quarter of 2017 compared to U.S. $45.57/bbl during the second quarter of 2016.

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 is primarily driven by the price of Brent, and the price received by the Company for crude oil and NGLs production from Asia Pacific is primarily driven by the price of Daqing. 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. In the second quarter of 2017, 69 percent of the Company's crude oil and NGLs production was heavy crude oil and bitumen compared to 64 percent in the second quarter of 2016.

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 second quarter of 2017 compared to the second quarter of 2016 primarily due to the increase in crude oil benchmark pricing.

Natural Gas Benchmarks

North American natural gas benchmarks were higher in the second quarter of 2017 as compared to the second quarter of 2016 due to a temporary decline in natural gas demand from Canadian oil sands operations in 2016, resulting from the wildfire at Fort McMurray, and an oversupply of natural gas in North America in 2016.

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 the Company's results.

Refining Benchmarks

The Chicago 3:2:1 crack spread is the key indicator for 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.

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 physical biofuel blending into a final gasoline or diesel has not been deducted from the Chicago 3:2:1 crack spread. 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 revenue 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 Refinery and the BP-Husky Toledo Refinery contain approximately 10 to 15 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. In the second quarter of 2017, the Canadian dollar averaged U.S. $0.744 compared to U.S. $0.776 in the second quarter of 2016.

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 5.101 in the second quarter of 2017 compared to RMB 5.070 in the second quarter of 2016.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the second quarter of 2017 on earnings before income taxes and net earnings. The table below reflects what the effect would have been on the financial results for the second quarter of 2017 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the second quarter of 2017. 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	2017 Second Quarter Average	Increase	Effect on Earnings before Income Taxes(1)		Effect on Net Earnings(1)	
			($ millions)	*($/share)(2)*	*($ millions)*	*($/share)(2)*
WTI benchmark crude oil price(3)(4)	48.29	*U.S. $1.00/bbl*	105	0.10	76	0.08
NYMEX benchmark natural gas price(5)	3.18	*U.S. $0.20/mmbtu*	11	0.01	8	0.01
WTI/Lloyd crude blend differential(6)	11.05	*U.S. $1.00/bbl*	(56)	(0.06)	(42)	(0.04)
Canadian light oil margins	0.054	*Cdn $0.005/litre*	12	0.01	9	0.01
Asphalt margins	21.56	*Cdn $1.00/bbl*	8	0.01	6	0.01
Chicago 3:2:1 crack spread	14.36	*U.S. $1.00/bbl*	110	0.11	70	0.07
Exchange rate (U.S. $ per Cdn $)(3)(7)	0.744	*U.S. $0.01*	(68)	(0.07)	(50)	(0.05)

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.5 million common shares outstanding as at June 30, 2017.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent and Daqing based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Excludes impact on asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

3. Strategic Plan

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 areas of focus:

- The Integrated Corridor includes natural gas, non-thermal oil, NGLs and thermal bitumen production from Western Canada, the Lloydminster upgrading and asphalt refining complex, the Husky Midstream Limited Partnership (35 percent working interest and operatorship), and the Lima and Toledo refineries in the U.S. Midwest. Gas production from the repositioned Western Canada portfolio is closely aligned with the Company's gas requirements for thermal bitumen and refining requirements and acts as a natural hedge.

- The Offshore business includes operations and exploration in the Asia Pacific region, primarily offshore China, Indonesia and Taiwan, and in the Atlantic, offshore Newfoundland and Labrador. Each area generates high-netback production, with near and long-term investment potential.

In the Integrated Corridor, the Company has a large and growing inventory of thermal bitumen projects in the Lloydminster region of Saskatchewan and Alberta, as well as the Tucker Thermal Project near Cold Lake and the Sunrise Energy Project north of Fort McMurray. These projects are physically integrated with the Downstream assets, which increases flexibility, provides for secure U.S. market access and increases margin capture.

Offshore in the Asia Pacific region, the Liwan Gas Project and series of natural gas fields in the Madura Strait offshore Indonesia are being developed through fixed-price contracts, providing insulation from commodity price instability. In the Atlantic, the Company continues to develop satellite tiebacks from the main White Rose field and is moving forward with the West White Rose development. Both Offshore regions leverage existing infrastructure to drive greater cost efficiencies, with products sold into regional and global markets.

4. Key Growth Highlights

The 2017 capital program reflects the Company's focus on returns from investment in a deep portfolio of opportunities that can generate increased funds from operations and free cash flow.

4.1 Upstream

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and NGLs (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGLs, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, offshore east coast of Canada (Atlantic) and offshore China and offshore Indonesia (Asia Pacific).

Thermal Developments

The Company continued to advance its inventory of thermal bitumen developments in the second quarter of 2017. 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 Projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 117,400 bbls/day in the second quarter of 2017 and is expected to average approximately 130,000 bbls/day by the fourth quarter of 2017.

Lloyd Thermal Projects

Development continues at the 10,000 bbls/day Rush Lake 2 thermal project. Construction of the central processing facility is progressing to schedule and drilling of the SAGD injector-producer well pairs will commence in the third quarter of 2017. First production is expected in the first half of 2019.

In late 2016, the Company sanctioned three Lloyd thermal projects with total design capacity of 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. Progress is being made towards regulatory approval, and first production for all three is expected in 2020.

Tucker Thermal Project

Drilling of a new 15-well pad was completed in the second quarter. Production from this new pad is expected to ramp up through the first half of 2018, with total production at the Tucker Thermal Project expected to grow towards its 30,000 bbls/day design capacity by the end of 2018.

Sunrise Energy Project

Average well rates continued to increase at the Sunrise Energy Project with total production averaging 38,300 bbls/day (19,150 bbls/day Husky working interest). Work is progressing to tie-in 14 previously drilled well pairs, with steaming now under way and first oil production by the end of the year.

Production will continue to ramp up in 2017 with expected average annual production in the range of 40,000 to 44,000 bbls/day (20,000 to 22,000 bbls/day Husky working interest).

Asia Pacific

China

Block 29/26

Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field at the Liwan Gas Project, continued in the second quarter.

Block 15/33 and 16/25

The Company expects to drill two exploration wells on both Block 15/33 and 16/25 offshore China in the 2018 timeframe.

Offshore Taiwan

Block DW-1

The Company is in the process of acquiring three-dimensional seismic survey data on the most attractive identified structures on the block.

Indonesia

Madura Strait

Progress continued on the natural gas developments in the Madura Strait Block.

The liquids-rich BD Gas Project in the Madura Strait began testing and commissioning in the second quarter and is expected to reach commercial production soon. Gas is being provided to the East Java market. The BD Gas Project produces through a shallow water wellhead platform to a purpose-built FPSO vessel, where the gas and liquids are processed. From there, the gas is transported by pipeline to an onshore gas distribution facility in East Java and then sold under fixed-price contracts into the regional gas market. The liquids are offloaded from the FPSO and sold separately. The project is expected to ramp up throughout 2017 towards full sales gas rate, 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 NGLs (2,400 bbls/day Husky working interest).

Construction of the shallow water platforms for the MDA-MBH fields has been completed and the platforms have been installed. Tendering for a floating production unit has been completed and a contract is in progress. First gas is expected in the 2019-2020 timeframe, with the additional MDK shallow water field expected to be tied in during the same period.

Total gross sales volumes from the BD Gas Project, MDA-MBH and MDK fields are expected to be approximately 250 mmcf/day of natural gas (100 mmcf/day Husky working interest) and 6,000 bbls/day (2,400 bbls/day Husky working interest) of associated NGLs once production is fully ramped up.

Pre-engineering activities are progressing at the MAC field, where an approved plan of development is in place. Additional discoveries in the region are being evaluated for potential development.

Anugerah

During 2015, the Company acquired two-dimensional and three-dimensional seismic survey data on the contract area. Results from analysis of this and other data are being evaluated to determine the potential for future drilling opportunities.

Atlantic

White Rose Field and Satellite Extensions

The Company and its partners have announced plans to move ahead with the West White Rose project. The project will be developed using a fixed drilling platform, which has received regulatory approval. Construction of the concrete gravity structure and associated drilling facilities, utilities, support services, and accommodations for personnel is scheduled to start in the fourth quarter of 2017. The platform will leverage existing offshore infrastructure, including the SeaRose FPSO vessel. First oil is expected in 2022 with an expected ramp-up to gross peak production capacity of 75,000 bbls/day (52,500 bbls/day Husky working interest) in 2025 as development wells are drilled and brought online. The cost of the project is expected to be $2.2 billion, net to Husky, over the next five years.

The Company continues to offset natural reservoir declines through infill and development well drilling at the White Rose field and satellite extensions. An infill well was completed at North Amethyst in February 2017 with peak production of approximately 8,600 bbls/day (Husky working interest). An additional development well is planned at South White Rose with first oil expected in the fourth quarter of 2017. All wells are tied back to the SeaRose FPSO, providing for improved capital efficiencies.

Atlantic Exploration

In May 2017, the Company announced a new discovery at Northwest White Rose. The White Rose A-78 well was drilled approximately 11 kilometres northwest of the SeaRose FPSO in the first quarter of 2017 and delineated a light oil column of more than 100 metres (gross). Evaluation of results is ongoing. The Company has a 93.23% working interest in the well.

The Company and its partner drilled two exploration wells in the Flemish Pass that did not encounter economic quantities of hydrocarbons. The Company holds a 35 percent non-operated working interest in existing discoveries at Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen. The Company and its partner continue to assess the commercial potential of these prospects.

Western Canada Resource Play Development

Oil and Natural Gas Resource Plays

The Company is advancing a 16-well development drilling program targeting the Wilrich formation in the Ansell and Kakwa areas.

The Company also continued a four-well drilling program targeting the oil and liquids-rich Montney formation in the Karr and Wembley areas.

4.2 Downstream

Downstream operations in the Integrated Corridor includes upgrading of heavy crude oil feedstock into synthetic crude oil in Canada (Upgrading), refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. Refining and Marketing). Upgrading, Canadian Refined Products and U.S. Refining and Marketing 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.

Canadian Refined Products

Progress continues to be made on the implementation of a single expanded truck transport network of approximately 160 sites. The consolidation of the two networks is expected in the second half of 2017.

Lima Refinery

The Company continued work on a crude oil flexibility project at the Lima Refinery. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada, providing the ability to swing between light and heavy crude oil feedstock. The first stage of the project was completed in 2016 and the Lima Refinery is now able to process up to 10,000 bbls/day of heavy crude oil feedstock. The full scope of the project is expected to be completed around the end of 2018.

Lloydminster Asphalt Expansion

FEED work continued on a potential 30,000 bbls/day expansion of the Company's asphalt processing capacity in Lloydminster with a final investment decision expected in 2018. This business continues to show strong returns through the cycle, and its expansion would provide an additional outlet for the Company's growing heavy crude oil and bitumen production.

5. Results of Operations

5.1 Upstream

Exploration and Production

Exploration and Production Earnings (Loss) Summary	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Gross revenues	**1,215**	1,044	**2,466**	1,880
Royalties	**(91)**	(90)	**(195)**	(144)
Net revenues	**1,124**	954	**2,271**	1,736
Purchases of crude oil and products	**1**	14	**1**	26
Production, operating and transportation expenses	**430**	442	**847**	893
Selling, general and administrative expenses	**61**	52	**118**	94
Depletion, depreciation, amortization and impairment ("DD&A")	**705**	542	**1,252**	1,104
Exploration and evaluation expenses	**56**	76	**77**	93
Loss (gain) on sale of assets	**(33)**	97	**(32)**	99
Other – net	**(39)**	8	**(24)**	6
Share of equity investment loss (gain)	**1**	1	**—**	2
Financial items	**34**	36	**65**	76
Recovery of income taxes	**(25)**	(86)	**(9)**	(179)
Net loss	**(67)**	(228)	**(24)**	(478)

Second Quarter

Exploration and Production net revenues increased by $170 million in the second quarter of 2017 compared to the second quarter of 2016, primarily due to higher realized North American commodity prices combined with increased production from the Company's thermal development projects, and increased natural gas and NGLs production in Asia Pacific. This was partially offset by lower oil and natural gas production in Western Canada due to the disposition of select legacy assets in 2016 and 2017.

Production, operating and transportation expenses decreased by $12 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to cost savings initiatives and lower production from Western Canada. This was partially offset by higher energy costs.

DD&A expense increased by $163 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to the recognition of a pre-tax impairment charge of $168 million on crude oil and natural gas assets in Western Canada during the second quarter of 2017.

Gain on sale of assets increased by $130 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to a gain on sale of select assets in Western Canada in 2017, compared to a loss in 2016.

Other net income increased by $47 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to partner share contributions related to the West White Rose Project.

Recovery of income taxes decreased by $61 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to higher net earnings in the second quarter 2017, partially offset by the recognition of an impairment charge in the second quarter of 2017.

Six Months

In the first six months of 2017, Exploration and Production net revenues increased by $535 million and production, operating and transportation expenses decreased by $46 million, compared to the same period in 2016, primarily due to the same factors which impacted the second quarter.

DD&A expense increased by $148 million, gain on sale of assets increased by $131 million and income tax recovery decreased by $170 million in the first six months of 2017 compared to the same period in 2016, primarily due to the same factors which impacted the second quarter.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Crude oil and NGLs *($/bbl)*				
Light and Medium crude oil	63.27	56.11	65.00	47.26
NGLs	38.00	36.68	43.26	34.18
Heavy crude oil	42.06	34.88	41.64	26.21
Bitumen	37.46	30.95	36.33	22.22
Total crude oil and NGLs average	44.53	39.94	44.81	32.00
Natural gas average *($/mcf)*	5.59	3.46	5.47	3.97
Total average *($/boe)*	41.58	34.59	41.59	29.62

Second Quarter

The average sales prices realized by the Company for crude oil and NGLs production increased by 11 percent in the second quarter of 2017 compared to the same period in 2016, reflecting an increase in commodity benchmark prices.

The average sales prices realized by the Company for natural gas production increased by 62 percent in the second quarter of 2017 compared to the same period in 2016. The increase in realized natural gas pricing was primarily due to a higher percentage of fixed priced natural gas production from the Liwan Gas Project relative to total natural gas production and higher North American benchmark pricing.

Six Months

In the first six months of 2017, the average sales prices realized by the Company for crude oil and NGLs production increased by 40 percent and the average sales prices realized by the Company for natural gas production increased by 38 percent compared to the same period in 2016, primarily due to the same factors which impacted the second quarter.

Daily Gross Production

Daily Gross Production	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Crude Oil and NGLs *(mbbls/day)*				
Western Canada				
Light and Medium crude oil	11.8	29.6	13.2	31.3
NGLs	10.8	8.0	9.4	8.4
Heavy crude oil	43.1	57.5	45.5	59.5
Bitumen(1)	117.4	88.0	118.9	84.9
	183.1	183.1	187.0	184.1
Atlantic				
White Rose and Satellite Fields – light crude oil	34.1	30.9	34.3	33.5
Terra Nova – light crude oil	3.9	1.8	4.5	3.1
	38.0	32.7	38.8	36.6
Asia Pacific				
Wenchang – light crude oil	6.2	7.1	6.4	7.2
Liwan and Wenchang – NGLs(2)	6.4	4.8	6.3	5.0
	12.6	11.9	12.7	12.2
	233.7	227.7	238.5	232.9
Natural gas *(mmcf/day)*				
Western Canada	382.2	441.5	395.9	475.2
Asia Pacific(2)	132.6	87.3	133.0	98.7
	514.8	528.8	528.9	573.9
Total *(mboe/day)*	319.5	315.8	326.7	328.6

(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 net working interest production from the Liwan Gas Project (49 percent).*

Crude Oil and NGLs Production

Second Quarter

Crude oil and NGLs production increased by 6.0 mbbls/day in the second quarter of 2017 compared to the second quarter of 2016 primarily due to the continued production ramp-up at the Sunrise Energy Project, new production from the Edam West, Vawn and Edam East thermal developments and strong performance from the Tucker Thermal Project. This was partially offset by lower production from Western Canada due to the disposition of select legacy assets in 2016 and 2017.

Six Months

Crude oil and NGLs production increased by 5.6 mbbls/day in the first six months of 2017 compared to the same period in 2016, primarily due to the same factors which impacted the second quarter.

Natural Gas Production

Second Quarter

Natural gas production decreased by 14.0 mmcf/day in the second quarter of 2017 compared to the second quarter of 2016. In Western Canada, natural gas production decreased by 59.3 mmcf/day primarily due to the disposition of select legacy assets during 2016 and 2017, natural reservoir declines from mature properties and strategic shut-ins due to unfavourable economics. In Asia Pacific, natural gas production increased by 45.3 mmcf/day due to increased gas demand in 2017 and a planned partial shut-down at the Liwan Gas Project in 2016 to install a second deepwater pipeline.

Six Months

Natural gas production decreased by 45.0 mmcf/day in the first six months of 2017 compared to the same period in 2016. In Western Canada, natural gas production decreased by 79.3 mmcf/day primarily due to the same factors which impacted the second quarter. In Asia Pacific, natural gas production increased by 34.3 mmcf/day primarily due to the same factors which impacted the second quarter and the resolution of issues with the gas buyer's onshore gas pipeline infrastructure that hindered production in the first quarter of 2016.

2017 Production Guidance

The following table shows actual daily production for the six months ended June 30, 2017, and the year ended December 31, 2016, as well as the previously issued production guidance for 2017.

		Actual Production	
	Guidance 2017	Six months ended June 30, 2017	Year ended December 31, 2016
Canada			
Light & medium crude oil *(mbbls/day)*	46 - 48	52	56
NGLs *(mbbls/day)*	8 - 9	9	8
Heavy crude oil & bitumen *(mbbls/day)*	167 - 173	164	151
Natural gas *(mmcf/day)*	345 - 353	396	442
Canada total *(mboe/day)*	278 - 288	292	289
Asia Pacific			
Light crude oil *(mbbls/day)*	5 - 6	6	7
NGLs *(mbbls/day)*	8 - 10	6	6
Natural gas *(mmcf/day)*	171 - 182	133	114
Asia Pacific total *(mboe/day)*	42 - 46	35	32
Total *(mboe/day)*	320 - 335	327	321

Royalties

Second Quarter

Royalty rates as a percentage of gross revenues averaged eight percent in the second quarter of 2017 compared to nine percent in the same period in 2016. Royalty rates in Western Canada averaged eight percent in both the second quarter of 2017 and of 2016. Royalty rates for Atlantic averaged nine percent in the second quarter of 2017 compared to 17 percent in the same period in 2016 primarily due to production shifting to lower rate fields and a prior period adjustment in 2016. Royalty rates in Asia Pacific averaged six percent in both the second quarter of 2017 and of 2016.

Six Months

Royalty rates as a percentage of gross revenues averaged eight percent in both the first six months of 2017 and of 2016. Royalty rates in Western Canada averaged eight percent in the first six months of 2017 compared to seven percent in the same period of 2016 primarily due to higher commodity prices. Royalty rates for the Atlantic Region averaged 12 percent in the first six months of 2017 compared to 14 percent in the same period of 2016 primarily due to the same factors which impacted the second quarter. Royalty rates in the Asia Pacific Region averaged six percent in the first six months of 2017 compared to five percent in the same period of 2016.

Operating Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Western Canada	**344**	350	**684**	716
Atlantic	**55**	61	**107**	113
Asia Pacific	**24**	23	**43**	47
Total	**423**	434	**834**	876
Per unit operating costs ($/boe)	**14.65**	13.90	**14.19**	13.59

Second Quarter

Total Exploration and Production operating costs were $423 million in the second quarter of 2017 compared to $434 million in the same period in 2016. Total unit operating costs averaged $14.65/boe in the second quarter of 2017 compared to $13.90/boe in the same period in 2016 with the increase primarily due to higher unit operating costs in Western Canada.

Per unit operating costs in Western Canada averaged $15.50/boe in the second quarter of 2017 compared to $13.49/boe in the same period in 2016. The increase in unit operating costs per boe was primarily due to higher energy costs, partially offset by cost savings initiatives realized in 2017.

Per unit operating costs in Atlantic averaged $15.82/bbl in the second quarter of 2017 compared to $20.27/bbl in the same period in 2016. The decrease in unit operating costs per boe was primarily due to higher production in 2017 and lower subsea maintenance costs in 2017.

Unit operating costs in Asia Pacific averaged $7.56/boe in the second quarter of 2017 compared to $9.91/boe in the same period in 2016. The decrease in unit operating costs per boe was primarily due to higher production at the Liwan Gas Project and cost saving initiatives.

Six Months

Total Exploration and Production operating costs were $834 million in the first six months of 2017 compared to $876 million in the same period in 2016. Total unit operating costs averaged $14.19/boe in the first six months of 2017 compared to $13.59/boe in the same period in 2016 with the increase primarily due to higher unit operating costs in Western Canada.

Per unit operating costs in Western Canada averaged $15.06/boe in the first six months of 2017 compared to $13.62/boe in the same period in 2016. The increase in unit operating costs per boe was primarily due to the same factors which impacted the second quarter.

Per unit operating costs in Atlantic averaged $15.22/boe in the first six months of 2017 compared to $16.92/boe in the same period in 2016. The decrease in unit operating costs per boe was primarily due to the same factors which impacted the second quarter combined with higher logistics costs.

Unit operating costs in Asia Pacific averaged $6.76/boe in the first six months of 2017 compared to $9.09/boe in the same period in 2016. The decrease in unit operating costs per boe was primarily due to the same factors which impacted the second quarter.

Exploration and Evaluation Expenses

($ millions)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Seismic, geological and geophysical	**31**	15	**50**	31
Expensed drilling	**19**	59	**19**	59
Expensed land	**6**	2	**8**	3
Total	**56**	76	**77**	93

Second Quarter

Exploration and evaluation expenses in the second quarter of 2017 were $56 million compared to $76 million in the second quarter of 2016. Expensed drilling decreased by $40 million in the second quarter of 2017 compared to the second quarter of 2016, primarily due to lower daily drilling rates for the two unsuccessful exploration wells in the Flemish Pass, compared to those for the two exploration wells expensed in 2016. The increase in seismic, geological and geophysical expense of $16 million is primarily due to increased seismic operations in both Western Canada, related to thermal developments, and Asia Pacific, related to the exploration block in offshore Taiwan.

Six Months

Exploration and evaluation expenses in the first six months of 2017 were $77 million compared to $93 million in the same period in 2016. The decrease in exploration and evaluation expenses was primarily due to the same factors which impacted the second quarter.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in the second quarter of 2017 compared to the second quarter of 2016 reflecting increased investment in Western Canada Resource Plays and Thermal Developments and Atlantic drilling. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[(1)] ($ millions)	Three months ended June 30, 2017	2016	Six months ended June 30, 2017	2016
Exploration				
Western Canada	**11**	2	**20**	4
Thermal Developments	**1**	1	**1**	4
Atlantic	**3**	8	**65**	19
Asia Pacific[(2)]	**1**	—	**3**	—
	16	11	**89**	27
Development				
Western Canada	**22**	37	**52**	82
Thermal Developments	**108**	54	**226**	140
Non-Thermal Developments	**21**	8	**32**	8
Atlantic	**87**	87	**130**	104
Asia Pacific[(2)]	**(4)**	51	**—**	62
	234	237	**440**	396
Acquisitions				
Western Canada	**15**	—	**25**	—
Thermal Developments	**42**	2	**42**	2
	307	250	**596**	425

(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.*

Western Canada

During the first six months of 2017, $97 million (16 percent) was invested in Western Canada, compared to $86 million (20 percent) in the same period in 2016. Capital expenditures in 2017 related primarily to resource play development drilling in the Wilrich formation in the Ansell and Kakwa areas and sustainment activities compared to 2016 where capital expenditures related primarily to the development of the Rainbow Lake NGLs project.

Thermal Developments

During the first six months of 2017, $269 million (45 percent) was invested in Thermal Developments, compared to $146 million (34 percent) in the same period in 2016. Capital expenditures in 2017 related primarily to the development of the Rush Lake 2 thermal development, a new pad at the Tucker Thermal Project and continued investment in the Sunrise Energy Project.

Non-Thermal Developments

During the first six months of 2017, $32 million (five percent) was invested in Non-Thermal Developments, compared to $8 million (two percent) in the same period in 2016. Capital expenditures in 2017 related primarily to sustainment activities.

Atlantic

During the first six months of 2017, $195 million (33 percent) was invested in Atlantic, compared to $123 million (29 percent) in the same period in 2016. Capital expenditures in 2017 related primarily to satellite field developments at North Amethyst, the South White Rose Extension and the West White Rose Project as well as delineation drilling northwest of the main White Rose field. The increase in capital expenditures in the first six months of 2017 compared to the same period in 2016 reflects the arrival of the Henry Goodrich rig in mid-2016 and the rig being fully operational for the first half of 2017.

Asia Pacific

The decrease in capital expenditures in the first six months of 2017, compared to the same period in 2016, reflects the installation of a second deepwater production pipeline at Liwan 3-1 in 2016.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled in Thermal and Western Canada Resource Play Developments during the three and six months ended June 30, 2017 and 2016:

	Three months ended June 30,				Six months ended June 30,			
	2017		2016		2017		2016	
Wells Drilled [1]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Thermal Developments	**33**	**33**	7	7	**42**	**42**	43	43
Western Canada Resource Play Development	**3**	**2**	—	—	**13**	**11**	2	1
	36	**35**	7	7	**55**	**53**	45	44

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

Offshore drilling activity

The following table discloses the Company's Atlantic drilling activity during the six months ended June 30, 2017:

Region	***Well***	***Working Interest***	***Well Type***
Atlantic	North Amethyst G-25 10	WI 68.875 percent	Development
Atlantic	White Rose A-78	WI 93.23 percent	Exploration
Atlantic	Bonaventure O-96	WI 35 percent	Exploration
Atlantic	Portugal Cove E-38	WI 35 percent	Exploration

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGLs, sulphur and petroleum coke production. The Company owns infrastructure in Western Canada, including pipeline and storage facilities, and has access to capacity on third party pipelines and storage facilities in both Canada and the U.S. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the U.S. market.

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets include approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets are held by Husky Midstream Limited Partnership (“HMLP“), of which the Company owns 35 percent, Power Assets Holdings Limited (“PAH“) owns 48.75 percent and Cheung Kong Infrastructure Holdings Limited (“CKI“) owns 16.25 percent. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets.

Infrastructure and Marketing Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Gross revenues	**426**	270	**759**	485
Purchases of crude oil and products	**408**	227	**703**	398
Infrastructure gross margin	**18**	43	**56**	87
Marketing and other	**(1)**	18	**35**	(84)
Total Infrastructure and Marketing gross margin	**17**	61	**91**	3
Production, operating and transportation expenses	**2**	7	**5**	15
Selling, general and administrative expenses	**1**	1	**2**	2
Depletion, depreciation, amortization and impairment	**1**	6	**1**	12
Loss (gain) on sale of assets	**—**	—	**1**	—
Other – net	**(9)**	(1)	**(12)**	(4)
Share of equity investment (gain)	**(24)**	—	**(48)**	—
Provisions for (recovery of) income taxes	**13**	13	**39**	(6)
Net earnings (loss)	**33**	35	**103**	(16)

Second Quarter

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $156 million and $181 million, respectively, in the second quarter of 2017 compared to the second quarter of 2016 primarily due to increased volumes.

Share of equity investment gain increased by $24 million in the second quarter of 2017 compared to the second quarter of 2016 due to the formation of HMLP in mid-2016.

Six Months

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $274 million and $305 million, respectively, in the first six months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the second quarter.

Marketing and other increased by $119 million in the first six months of 2017 compared to the same period in 2016 primarily due to crude oil marketing gains from widening price differentials between Canada and the U.S. in 2017 and unrealized mark-to-market losses recognized on the Company's risk management positions in 2016.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Gross revenues	**227**	369	**611**	650
Purchases of crude oil and products	**144**	222	**392**	359
Gross margin	**83**	147	**219**	291
Production, operating and transportation expenses	**54**	40	**103**	76
Selling, general and administrative expenses	**3**	1	**5**	2
Depletion, depreciation, amortization and impairment	**19**	27	**38**	55
Other – net	**—**	(1)	**—**	(1)
Provisions for income taxes	**2**	22	**20**	43
Net earnings	**5**	58	**53**	116
Upgrader throughput *(mbbls/day)*(1)	**41.1**	76.9	**59.4**	77.3
Total sales *(mbbls/day)*	**40.3**	76.5	**58.2**	77.4
Synthetic crude oil sales *(mbbls/day)*	**30.3**	59.8	**42.1**	58.8
Upgrading differential *($/bbl)*	**18.70**	20.85	**19.79**	21.55
Unit margin *($/bbl)*	**22.63**	21.12	**20.79**	20.66
Unit operating cost *($/bbl)*(2)	**14.44**	5.72	**9.58**	5.40

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

Second Quarter

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

Upgrader gross revenues decreased by $142 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to lower sales volumes resulting from a planned major turnaround in the second quarter of 2017. Sales volumes decreased by 36.2 mbbls/day, or 47 percent, and throughput decreased by 35.8 mbbls/day, or 47 percent, compared to the second quarter of 2016. This is partially offset by the higher price of Husky Synthetic Blend in the the second quarter of 2017, which averaged $63.33/bbl compared to $60.70/bbl in the second quarter of 2016.

Upgrader feedstock purchases decreased by $78 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to the planned major turnaround in the second quarter of 2017.

Upgrader gross margin decreased by $64 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to the planned major turnaround in the second quarter of 2017 and lower average upgrading differentials. During the second quarter of 2017, the upgrading differential averaged $18.70/bbl, a decrease of $2.15/bbl, or 10 percent compared to the second quarter of 2016. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in the upgrading differential was due to the tightening of the light/heavy differentials.

Six Months

Upgrader gross revenues decreased by $39 million in the first six months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the second quarter offset by the price of Husky Synthetic Blend of $65.42/bbl in the first six months of 2017 compared to $53.35/bbl in the same period in 2016.

Upgrader feedstock purchases increased by $33 million in the first six months of 2017 compared to the same period in 2016 primarily due to the increase in the average cost of crude oil feedstock, partially offset by lower sales volumes resulting from the planned turnaround in the second quarter of 2017.

Upgrader gross margin decreased by $72 million in the first six months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the second quarter. During the first six months of 2017, the upgrading differential averaged $19.79/bbl, a decrease of $1.76/bbl, or eight percent compared to the same period in 2016.

Production, operating and transportation expenses increased by $27 million in the first six months of 2017 compared to the same period in 2016 primarily due to higher maintenance, labour and energy costs.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Gross revenues	**602**	585	**1,170**	1,020
Purchases of crude oil and products	**477**	440	**922**	779
Gross margin				
Fuel	**32**	37	**60**	63
Refining	**37**	32	**79**	49
Asphalt	**43**	61	**83**	100
Ancillary	**13**	15	**26**	29
	125	145	**248**	241
Production, operating and transportation expenses	**67**	64	**127**	113
Selling, general and administrative expenses	**11**	7	**22**	14
Depletion, depreciation, amortization and impairment	**27**	25	**56**	49
Gain on sale of assets	**—**	(1)	**—**	(1)
Other – net	**—**	—	**—**	(1)
Financial items	**3**	1	**6**	3
Provisions for income taxes	**5**	13	**10**	17
Net earnings	**12**	36	**27**	47
Number of fuel outlets[(1)]	**476**	482	**478**	482
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**6.5**	6.8	**6.5**	6.5
Fuel sales per retail outlet *(thousands of litres/day)*	**11.8**	11.6	**11.6**	11.3
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**9.7**	5.1	**10.7**	8.1
Lloydminster Refinery *(mbbls/day)*	**19.5**	28.2	**23.5**	28.1
Ethanol production *(thousands of litres/day)*	**709.9**	809.2	**774.4**	810.0

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

Second Quarter

Canadian Refined Products gross revenues increased by $17 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to higher sales volume at the Prince George Refinery and higher refined product prices at the Lloydminister Refinery, partially offset by lower sales volumes at the Lloydminster Refinery resulting from a planned turnaround in the second quarter of 2017.

Canadian Refined Products purchases of crude oil and products increased by $37 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to higher commodity pricing.

Throughput at the Prince George Refinery increased by 4.6 mbbls/day, or 90 percent, due to a planned turnaround completed in the second quarter of 2016. Fuel sales per retail outlet increased by 0.2 mbbls/day, or two percent, compared to the second quarter of 2016. Ethanol production decreased by 99.3 thousands of litres/day, or 12 percent, compared to the second quarter of 2016.

Six Months

Canadian Refined Products gross revenues increased by $150 million in the first six months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the second quarter as well as higher commodity pricing.

Canadian Refined Products purchases of crude oil and products increased by $143 million in the first six months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the second quarter.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Gross revenues	**2,400**	1,337	**4,840**	2,463
Purchases of crude oil and products	**2,159**	1,083	**4,399**	2,123
Gross margin	**241**	254	**441**	340
Production, operating and transportation expenses	**137**	127	**277**	264
Selling, general and administrative expenses	**3**	3	**7**	6
Depletion, depreciation, amortization and impairment	**93**	77	**182**	158
Other – net	**(14)**	(50)	**(17)**	(175)
Financial items	**3**	1	**6**	2
Provisions for (recovery of) income taxes	**7**	35	**(5)**	31
Net earnings (loss)	**12**	61	**(9)**	54
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**174.1**	103.9	**173.1**	115.7
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**71.1**	41.2	**74.0**	55.1
Refining margin *(U.S. $/bbl crude throughput)*	**7.42**	16.46	**7.87**	9.00
Refinery inventory *(mmbbls)* [1]	**8.4**	11.1	**8.4**	11.1

[1] Feedstock and refined products are included in refinery inventory.

Second Quarter

U.S. Refining and Marketing gross revenues increased by $1,063 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to higher sales volume as a result of scheduled major planned turnarounds completed in the second quarter of 2016.

U.S. Refining and Marketing purchases of crude oil and products increased by $1,076 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to higher crude oil feedstock costs, and increased throughput at both the Lima and BP-Husky Toledo Refineries. Throughput at the Lima Refinery increased by 70.2 mbbls/day when compared to the second quarter of 2016 resulting from a scheduled major turnaround in 2016 and the isocracker being fully in service in 2017. Throughput at the BP-Husky Toledo Refinery increased by 29.9 mbbls/day compared to the second quarter of 2016 primarily due to a scheduled major turnaround in 2016.

U.S. Refining and Marketing gross margin decreased by $13 million in the second quarter of 2017 compared to the second quarter of 2016 primarily due to lower Chicago 3:2:1 crack spreads, partially offset by higher sales volumes and higher throughput at the refineries.

Other – net income decreased by $36 million in the second quarter of 2017 compared to the second quarter of 2016 due to reduced insurance recoveries associated with the isocracker unit fire in 2016.

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 FIFO impact was a reduction in net earnings of approximately $25 million in the second quarter of 2017 compared to an increase in net earnings of $88 million in the second quarter of 2016.

Six Months

U.S. Refining and Marketing gross revenues increased by $2,377 million and purchases of crude oil and products increased by $2,276 million in the first six months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the second quarter.

U.S. Refining and Marketing gross margin increased by $101 million in the first six months of 2017 compared to the same period in 2016 primarily due to higher sales volumes, partially offset by lower Chicago 3:2:1 crack spreads.

Other – net income decreased by $158 million in the first six months of 2017 compared to the same period in 2016 due to reduced insurance recoveries associated with the isocracker unit fire in 2016.

Downstream Capital Expenditures

In the first six months of 2017, Downstream capital expenditures totalled $340 million compared to $505 million in the same period in 2016. In Canada, capital expenditures of $237 million were primarily related to the scheduled turnarounds at the Lloydminster Upgrader and Lloydminster asphalt refinery in the second quarter of 2017. At the Lima Refinery, capital expenditures of $56 million were primarily related to various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures of $47 million (Husky's 50 percent share) were primarily related to environmental protection initiatives. The decrease in downstream capital expenditures was primarily due to the completion of turnarounds and the feedstock optimization project in U.S. Refining and Marketing in 2016.

5.3 Corporate

Corporate Summary	Three months ended June 30,		Six months ended June 30,	
($ millions) income (expense)	**2017**	2016	**2017**	2016
Selling, general and administrative expenses	**(63)**	(82)	**(122)**	(145)
Depletion, depreciation and amortization	**(17)**	(20)	**(33)**	(41)
Other – net	**3**	(65)	**3**	(131)
Net foreign exchange gain (loss)	**(11)**	(9)	**(13)**	4
Finance income	**8**	—	**13**	5
Finance expense	**(62)**	(58)	**(117)**	(122)
Recovery of income taxes	**54**	76	**97**	53
Net loss	**(88)**	(158)	**(172)**	(377)

Second Quarter

The Corporate segment reported a net loss of $88 million in the second quarter of 2017 compared to a net loss of $158 million in the second quarter of 2016. Other – net expense of $65 million in the second quarter of 2016 related to losses on the Company's short-term hedging program, which concluded in June 2016.

Six Months

The Corporate segment reported a net loss of $172 million in the first six months of 2017 compared to a net loss of $377 million in the same period in 2016. Other – net expense of $131 million related primarily to losses on the Company's short term hedging program which concluded in June 2016. Net foreign exchange loss increased by $17 million due to the items noted below.

Foreign Exchange Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Non-cash working capital gain (loss)	**14**	(7)	**(5)**	(20)
Other foreign exchange gain (loss)	**(25)**	(2)	**(8)**	24
Net foreign exchange gain (loss)	**(11)**	(9)	**(13)**	4
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.751**	U.S. $0.771	**U.S. $0.745**	U.S. $0.723
At end of period	**U.S. $0.770**	U.S. $0.769	**U.S. $0.770**	U.S. $0.769

Included in other foreign exchange gains are realized and unrealized foreign exchange gains on working capital and intercompany financing. The foreign exchange gains and losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period. The Company manages its exposure to foreign currency fluctuations in order to minimize the impact of foreign exchange gains and losses on the condensed interim consolidated financial statements.

Consolidated Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Recovery of income taxes	**(52)**	(79)	**(42)**	(147)
Cash income taxes paid (recovered)	**66**	(21)	**87**	(56)

Second Quarter

Consolidated income taxes were a recovery of $52 million in the second quarter of 2017 compared to a recovery of $79 million in the second quarter of 2016. The decrease in consolidated income tax recovery was primarily due to the increase in earnings before income tax in the second quarter of 2017 compared to the same period in 2016.

Six Months

Consolidated income taxes were a recovery of $42 million in the first six months of 2017 compared to a recovery of $147 million in the same period in 2016. The increase in consolidated income taxes was primarily due to the same factors which impacted the second quarter.

6. Risk Management and Financial Risks

6.1 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 February 24, 2017. The Company has processes in place designed to identify the principal risks of the business and put in place appropriate mitigation to manage such risks where possible. The Company's exposure to operational, political, environmental, financial, liquidity and contract and credit risk has not materially changed since December 31, 2016, which was discussed in the Company's MD&A for the year ended December 31, 2016.

6.2 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 firm commitments for the purchase or sale of crude oil and natural gas. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable, inventory, other assets, accounts payable and accrued liabilities and other liabilities.

At June 30, 2017, 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. At June 30, 2017, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that were previously designated as a fair value hedge was $1 million. The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of less than $1 million for the three and six months ended June 30, 2017.

During 2014, the Company discontinued its cash flow hedge with respect to forward starting interest rate swaps. These forward starting interest rate swaps were settled and derecognized. Accordingly, the accrued gain in other reserves is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated. The amortization period is 10 years. At June 30, 2017, the balance in other reserves related to the accrued gain was $16 million, net of tax of $6 million. The amortization of the accrued gain resulted in an offset to finance expenses of $1 million and $2 million respectively for the three and six months ended June 30, 2017. Refer to the Interest Rate Risk Management disclosure within Note 14 of the condensed interim consolidated financial statements.

Foreign Currency Risk Management

At June 30, 2017, 67 percent or CDN $3.9 billion (U.S. $3.0 billion) 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 and six months ended June 30, 2017, the Company incurred an unrealized gain of $88 million and unrealized gain of $115 million, respectively, arising from the translation of the debt, net of tax of $14 million and $18 million, respectively, which was recorded in hedge of net investment within other comprehensive income ("OCI").

The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery, and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At June 30, 2017, the Company's share of this obligation was U.S. $78 million including accrued interest. At June 30, 2017, the cost of a Canadian dollar in U.S. currency was $0.770.

7. Liquidity and Capital Resources

7.1 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 June 30, 2017, the Company had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities [1]	**750**	**309**
Syndicated credit facilities [2]	**4,000**	**3,800**
	4,750	**4,109**

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

At June 30, 2017, the Company had $4,109 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $309 million are short-term uncommitted credit facilities. A total of $441 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper. At June 30, 2017, the Company had no direct borrowing against committed credit facilities. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2017, working capital was $2,232 million compared to $1,125 million at December 31, 2016.

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 June 30, 2017.

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

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

On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020. In addition, the Company's leverage covenant under both of its revolving syndicated credit facilities ($2.0 billion maturing June 19, 2018 and $2.0 billion maturing March 9, 2020) was modified to a debt to capital covenant. The debt to capital covenant is 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. At June 30, 2017, the Company was in compliance with the syndicated credit facility covenants and assesses the risk of non-compliance to be low.

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027. This was completed by way of a prospectus supplement dated March 7, 2017 to the Company's 2015 Canadian Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

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 replaces the 2015 Canadian 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.

As at June 30, 2017, the Company has $3.0 billion in unused capacity under the 2017 Canadian Shelf Prospectus and U.S. $3.0 billion in unused capacity under the U.S. Shelf Prospectus and related U.S. registration statement. The ability of the Company to utilize the capacity under its 2017 Canadian Shelf Prospectus and U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

7.2 Capital Structure

Capital Structure *($ millions)*	**June 30, 2017** **Outstanding**
Total debt [(1)]	5,952
Common shares, preferred shares, retained earnings and accumulated OCI	17,394

(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 (excluding non-controlling interest) and debt which totalled $23.3 billion as at June 30, 2017 (December 31, 2016 – $23.0 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 11). 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 June 30, 2017, debt to capital employed was 25.5 percent (December 31, 2016 – 23.2 percent) and debt to funds from operations was 2.2 times (December 31, 2016 – 2.4 times).

The increase in the Company's debt to capital employed as at June 30, 2017 is due to the issuance of $750 million in notes during the first six months of 2017. The decrease in debt to funds from operations ratio as at June 30, 2017 is due to higher net earnings from higher global commodity prices offset by the issuance of those notes above. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle, which measures include, but are not limited to, a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the sale of non-core assets in Western Canada and the continued transition to lower sustaining and higher return Lloyd thermal projects.

7.3 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, 2016 under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2016. During the second quarter of 2017, 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.

7.4 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. For the three and six months ended June 30, 2017, the Company charged HMLP $57 million and $153 million, respectively, related to construction and management services, and the Company had purchases from HMLP of $55 million and $104 million respectively, related to the use of the pipeline for the Company's blending, transportation and storage activities. As at June 30, 2017, the Company had $33 million due from HMLP and nil due to HMLP related to these transactions. All transactions with HMLP have been measured at fair value.

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. 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 and six months ended June 30, 2017, the amount of natural gas sales to Meridian totalled $13 million and $26 million, respectively, the amount of steam purchased by the Company from Meridian totalled $4 million and $9 million, respectively, and the total cost recovery by the Company for facilities services was $5 million and $7 million, respectively. At June 30, 2017, the Company had $2 million due from Meridian with respect to these transactions.

At June 30, 2017, $32 million of the Company's May 11, 2009, 7.25 percent senior notes, maturing December 2019, were held by a related party, Ace Dimension Limited, and are included in long-term debt in the Company's condensed interim consolidated financial statements. The related party transaction was measured at fair market value at the date of the transaction and has been carried out on the same terms as applied with unrelated parties.

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

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

8. 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, 2016, as well as critical areas of judgments have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

9. Recent Accounting Standards and Changes in Accounting Policies

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

Recent Accounting Standards

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 Loss 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 completing the project awareness and engagement phase of implementing IFRS 16. The impact on the Company's consolidated financial statements upon adoption of IFRS 16 is currently being assessed.

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year 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. Early adoption is permitted.

The implementation of IFRS 15 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 15 to stakeholders.
- Scoping - This phase focuses on identifying the Company's major revenue streams, documenting how and when revenue is currently recognized and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development - Steps in this phase include addressing any potential differences in revenue recognition identified in the scoping phase, according to the priority assigned. This involves detailed analysis of the IFRS 15 revenue recognition criteria, review of contracts with customers to ensure revenue recognition practices are in accordance with IFRS 15 and evaluating potential changes to revenue processes and systems.

- Implementation - This phase includes implementing the changes required for compliance with IFRS 15. 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 15.

The Company is currently in the scoping phase of implementation. No material impact is expected on the Company's consolidated financial statements upon adoption of IFRS 15.

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 more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard is effective for annual periods beginning on or after January 1, 2018, with required retrospective application and early adoption permitted.

The implementation of IFRS 9 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 9 to stakeholders.
- Scoping - This phase focuses on identifying the Company's financial instruments, determining accounting treatment for in-scope financial instruments under IFRS 9, and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development - This phase includes addressing differences in accounting for financial instruments. Steps in this phase involve detailed analysis of the IFRS 9 recognition impacts, measurement and disclosure requirements, and evaluating potential changes to accounting processes.
- Implementation - This phase includes implementing the changes required for compliance with IFRS 9. 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 preparation of disclosures under IFRS 9.

The Company is currently in the implementation phase of implementing IFRS 9. The Company intends to retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 9 is not expected to have a material impact on the Company's consolidated financial statements.

Changes in Accounting Policies

Effective January 1, 2017, the Company adopted the following new accounting standards issued by the IASB:

Amendments to IAS 7 Statements of Cash Flows

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

10. Outstanding Share Data

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

Issued and outstanding: July 17, 2017:

• common shares	1,005,451,854
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	23,674,621
• stock options exercisable	13,939,883

11. Reader Advisories

This MD&A should be read in conjunction with the condensed interim consolidated financial statements and related Notes.

Readers are encouraged to refer to the Company's MD&A for the year ended December 31, 2016, the 2016 consolidated financial statements and the Annual Information Form dated February 24, 2017 filed with Canadian securities regulatory authorities and the 2016 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 June 30, 2017 and the six months ended June 30, 2017 are compared to the results for the three months ended June 30, 2016 and the six months ended June 30, 2016. Discussions with respect to the Company's financial position as at June 30, 2017 are compared to its financial position as at December 31, 2016. 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 June 30, 2017 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Non-GAAP Measures

Disclosure of non-GAAP Measurements

The Company uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this MD&A and related disclosures are: adjusted net earnings (loss), funds from operations, free cash flow, debt to capital employed, debt to funds from operations and LIFO. None of these measurements are used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for 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 measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP measures used in this MD&A and related disclosures are defined below.

Adjusted Net Earnings (Loss)

The term ”adjusted net earnings (loss)” is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, ”net earnings (loss)” as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings (loss) is comprised of net earnings (loss) and excludes items such as after-tax property, plant and equipment impairment charges (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. Adjusted net earnings (loss) was redefined in the second quarter of 2016. Previously, adjusted net earnings (loss) was defined as net earnings (loss) plus after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs.

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the three and six months ended June 30, 2017 and 2016:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		**2017**	2016	**2017**	2016
GAAP	Net loss	**(93)**	(196)	**(22)**	(654)
	Impairment of property, plant and equipment, net of tax	**123**	12	**123**	12
	Exploration and evaluation asset write-downs, net of tax	**3**	22	**4**	22
	Loss (gain) on sale of assets, net of tax	**(23)**	71	**(23)**	71
Non-GAAP	Adjusted net earnings (loss)	**10**	(91)	**82**	(549)

Debt to Capital Employed

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

Debt to 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 measurement 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 June 30, 2017, and December 31, 2016:

($ millions)	**June 30, 2017**	December 31, 2016
Total debt	**5,952**	5,339
Funds from operations[(1)]	**2,657**	2,198
Debt to funds from operations	**2.2**	2.4

[(1)] *Annualized using twelve month rolling figures.*

Funds from Operations and Free Cash Flow

The term ”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 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 term “free cash flow” 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. Free cash flow is presented to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures.

The following table shows the reconciliation of net losses to funds from operations and free cash flow, and related per share amounts for the three and six months ended June 30, 2017, and 2016:

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Net loss	**(93)**	(196)	**(22)**	(654)
Items not affecting cash:				
Accretion	**29**	33	**57**	67
Depletion, depreciation, amortization and impairment	**862**	697	**1,562**	1,419
Exploration and evaluation expenses	**4**	30	**5**	30
Deferred income taxes	**(57)**	(108)	**(51)**	(115)
Foreign exchange loss (gain)	**15**	12	**(2)**	13
Stock-based compensation	**8**	8	**9**	25
Loss (gain) on sale of assets	**(33)**	96	**(31)**	98
Unrealized mark to market loss (gain)	**18**	(83)	**(32)**	40
Share of equity investment loss	**(23)**	1	**(48)**	2
Other	**5**	(2)	**(3)**	(3)
Settlement of asset retirement obligations	**(20)**	(23)	**(68)**	(45)
Deferred revenue	**—**	40	**—**	40
Change in non-cash working capital	**98**	(43)	**58**	(333)
Cash flow - operating activities	**813**	462	**1,434**	584
Change in non-cash working capital	**(98)**	43	**(58)**	333
Funds from operations	**715**	505	**1,376**	917
Capital expenditures	**(580)**	(595)	**(964)**	(1,005)
Free cash flow	**135**	(90)	**412**	(88)
Funds from operations – basic	**0.71**	0.50	**1.37**	0.91
Funds from operations – diluted	**0.71**	0.50	**1.37**	0.91

LIFO

The Chicago 3:2:1 crack spread 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 crack spread.

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.

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*
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	*Including 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*
Free Cash Flow	*Funds from operations less capital expenditures*
Funds from Operations	*Funds from operations equals 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*
High-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as high-TAN crudes*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
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 mineral substances in association therewith*
Seismic survey	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Common shares, preferred shares, retained earnings and other reserves*
Steam-oil ratio	*Measures the volume of steam used to produce one unit volume of oil*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt, including long-term debt due within one year, and short-term debt*
Turnaround	*Performance of plant or facility maintenance*

Abbreviations

AER	*Alberta Energy Regulator*	*mboe/day*	*thousand barrels of oil equivalent per day*
bbls	*barrels*	*mcf*	*thousand cubic feet*
bbls/day	*barrels per day*	*MD&A*	*Management's Discussion and Analysis*
boe	*barrels of oil equivalent*	*mmbbls*	*million barrels*
boe/day	*barrels of oil equivalent per day*	*mmboe*	*million barrels of oil equivalent*
DD&A	*depletion, depreciation and amortization*	*mmbtu*	*million British Thermal Units*
EDGAR	*Electronic Data Gathering, Analysis, and Retrieval system (U.S.A.)*	*mmcf*	*million cubic feet*
FEED	*front end engineering and design*	*mmcf/day*	*million cubic feet per day*
FIFO	*first in first out*	*m3*	*cubic meter*
FPSO	*Floating production, storage and offloading vessel*	*NGLs*	*natural gas liquids*
GAAP	*Generally Accepted Accounting Principles*	*NIT*	*NOVA Inventory Transfer*
GJ	*gigajoule*	*NYMEX*	*New York Mercantile Exchange*
IAS	*International Accounting Standard*	*OCI*	*other comprehensive income*
IASB	*International Accounting Standards Board*	*OPEC*	*Organization of the Petroleum Exporting Countries*
ICFR	*Internal Controls over Financial Reporting*	*RIN*	*Renewable Identification Number*
IFRS	*International Financial Reporting Standards*	*RMB*	*Chinese Yuan*
LIFO	*Last in first out*	*SAGD*	*Steam Assisted Gravity Drainage*
mbbls	*thousand barrels*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
mbbls/day	*thousand barrels per day*	*WTI*	*West Texas Intermediate*
mboe	*thousand barrels of oil equivalent*		

12. Forward-Looking Statements and Information

Certain statements in this document are forward-looking statements and information (collectively, “forward-looking statements”), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as “will likely result”, “are expected to”, “will continue”, “is anticipated”, “is targeting”, “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 2017 production guidance, including guidance for specified areas and product types; the Company’s objective of maintaining stated debt to capital employed and debt to funds from operations ratio targets; and the Company’s 2017 Upstream capital expenditure program;

- with respect to the Company's Thermal Developments: the Company’s forecasted daily total bitumen production for the fourth quarter of 2017; progress of the construction of the central processing facility and anticipated timing of drilling of the SAGD injector-producer well pairs at the Company's Rush Lake 2 thermal development; anticipated timing of first production from and design capacity of the Company’s Rush Lake 2 thermal development and its three Lloyd thermal projects at Dee Valley, Spruce Lake North and Spruce Lake Central; production expectations for the Tucker Thermal Project for 2018; the expected timing of the commencement of steaming and first oil production at the 14 previously drilled well pairs at the Sunrise Energy Project; and the Company’s forecasted 2017 average annual production from the Sunrise Energy Project;

- with respect to the Company's Offshore business in Asia Pacific: the Company’s drilling plans at Block 15/33 and Block 16/25 located offshore China; the expected timing of ramp-up to full gas sales rate, and gross daily sales targets of natural gas and NGLs, at the BD Gas Project; the expected timing of first gas at the MDA-MBH fields; the expected timing of tie-in of the additional MDK shallow water field; and anticipated combined daily gross sales volumes from the BD Gas Project and the MDA-MBH and MDK fields once production is fully ramped up;

- with respect to the Company's Offshore business in the Atlantic: the expected timing of construction of the concrete gravity structure and associated drilling facilities, utilities, support services and accommodations for personnel at the West White Rose project; the expected timing of first oil, the expected timing and volume of gross peak production and the expected cost over the next five years of the West White Rose project; and the expected timing of first oil from an additional development well at South White Rose;

- with respect to the Company's Western Canada Resource Play Development: the Company's strategic and drilling plans for its Western Canada portfolio; and

- with respect to the Company's Downstream operating segment: the expected timing of the implementation of a single expanded truck transport network; the expected timing for completion of the crude oil flexibility project at the Lima Refinery; and the expected timing of a final investment decision on the potential expansion of the Company's Lloydminster asphalt refinery.

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

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers 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, 2016 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.