MANAGEMENT'S DISCUSSION AND ANALYSIS

October 29, 2015

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1. Summary of Quarterly Results

Quarterly Summary	Three months ended							
($ millions, except where indicated)	**Sept. 30 2015**	Jun. 30 2015	Mar. 31 2015	Dec. 31 2014	Sept. 30 2014	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013
Production *(mboe/day)*	**333.0**	336.9	356.0	359.6	341.1	333.6	325.9	308.3
Gross revenues and marketing and other	**4,286**	4,526	4,086	5,875	6,690	6,614	5,943	6,132
Net earnings (loss)	**(4,092)**	120	191	(603)	571	628	662	177
Per share – Basic	**(4.17)**	0.11	0.19	(0.62)	0.58	0.63	0.67	0.18
Per share – Diluted	**(4.19)**	0.10	0.17	(0.65)	0.52	0.63	0.66	0.18
Adjusted net earnings (loss)(1)	**(101)**	124	191	148	572	629	670	376
Cash flow from operations(1)	**674**	1,177	838	1,145	1,341	1,504	1,545	1,143
Per share – Basic	**0.68**	1.20	0.85	1.16	1.36	1.53	1.57	1.16
Per share – Diluted	**0.68**	1.20	0.85	1.16	1.36	1.52	1.57	1.16

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

Performance

- Net loss of $4,092 million in the third quarter of 2015 included after-tax property, plant and equipment and goodwill impairment charges of $3,824 million and an after-tax exploration and evaluation asset write-down of $167 million related to crude oil and natural gas assets located in Western Canada.
- Adjusted net loss, which excludes charges for impairments and write-downs, was $101 million in the third quarter of 2015 compared to adjusted net earnings of $572 million in the third quarter of 2014 with the decline due to:
  - Lower realized crude oil prices due to weakened market benchmarks;
  - Decreased crude oil production in Western Canada and the Atlantic Region; and
  - A $35 million after-tax work commitment penalty in Western Canada;
  - Partially offset by lower royalties, lower operating costs and a weaker Canadian dollar.
- Cash flow from operations decreased by $667 million to $674 million in the third quarter of 2015 compared to $1,341 million in the third quarter of 2014 primarily due to lower realized commodity prices, partially offset by lower royalties, lower operating costs and a weaker Canadian dollar.

- Production decreased by 8.1 mboe/day or two percent to 333.0 mboe/day in the third quarter of 2015 compared to the third quarter of 2014 as a result of:
    - Lower production in Western Canada due to natural reservoir declines at mature crude oil properties, higher turnaround activity and limited reinvestment in a low commodity price environment; and
    - Natural reservoir declines at mature fields in the Atlantic Region;
    - Partially offset by new production from the Rush Lake heavy oil thermal development which began producing crude oil early in the third quarter of 2015;
    - Higher crude oil production at Wenchang in the Asia Pacific Region where a planned turnaround on the FPSO vessel offstation impacted production in the third quarter of 2014;
    - New production in the Atlantic Region from the South White Rose extension; and
    - Production from the Sunrise Energy Project which began producing bitumen late in the first quarter of 2015.

Key Projects

- Production continued to ramp up at the Sunrise Energy Project in the third quarter of 2015. Production from the project averaged approximately 10,000 bbls/day (5,000 bbls/day net to Husky) in September 2015 and is expected to ramp up to 60,000 bbls/day (30,000 bbls/day net to Husky) around the end of 2016. Steam operations commenced in early September 2015 at the second of two processing plants. Fifty-five well pairs are being steamed with 36 currently producing bitumen.
- First oil was achieved at the Rush Lake heavy oil thermal development on July 16, 2015. Production from the development averaged 10,050 bbls/day in the month of September with current rates exceeding its nameplate capacity.
- Construction continued at the two 10,000 bbls/day Edam East and Vawn and the 4,500 bbls/day Edam West heavy oil thermal developments. First production is now expected ahead of schedule from Edam East in the second quarter of 2016 and from Vawn and Edam West in the third quarter of 2016.
- In the Atlantic Region, production commenced from the second well at the South White Rose extension on September 6, 2015. Peak production of 15,000 bbls/day net to Husky on the first two wells was reached in early September.
- At the North Amethyst field, drilling of the Hibernia formation well has been deferred to 2016/2017, subject to rig availability.
- At the Liwan Gas Project, combined gross production from the Liwan 3-1 and Liuhua 34-2 gas fields was maintained at 295 mmcf/day and gross sales of associated natural gas liquids were approximately 14.8 mboe/day in the third quarter of 2015. Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, continued in the quarter.
- In Indonesia, progress continued on the shallow water gas developments in the Madura Strait Block. Wellhead platform and pipeline infrastructure construction at the liquids-rich BD field is ongoing and approximately 54 percent complete. The sailout of the platform jacket and topsides took place in October 2015. Construction of the FPSO vessel is approximately 25 percent complete and all long lead time items have been ordered. The tendering process for the MDA and MBH development projects continued.
- Western Canada natural gas resource play development progressed in the third quarter of 2015 with seven wells (gross) drilled and seven wells (gross) completed at key plays including continued development of the Ansell natural gas resource play.
- Construction is ongoing for the expansion of the South Saskatchewan Gathering System which will create incremental capacity to accommodate production from the Rush Lake, Edam East, Vawn and Edam West heavy oil thermal developments. Construction is now more than three quarters complete.
- Husky and Imperial Oil have entered into a contractual agreement to create a single expanded truck transport network of approximately 160 sites. The agreement is subject to approval by Canada’s Competition Bureau and other closing conditions.

Financial

- Dividends on common shares of $295 million for the second quarter of 2015 were declared during the third quarter of 2015, of which $291 million and $4 million were paid in cash and common shares, respectively, on October 1, 2015.
- Dividends on preferred shares of $10 million were declared and paid in the third quarter of 2015.

2. Business Environment

The following average benchmarks have been provided to assist in understanding the Company's financial results.

Average Benchmarks		Three months ended Sept. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sept. 30, 2014	Nine months ended Sept. 30, 2015	Sept. 30, 2014
WTI crude oil[1]	*(U.S. $/bbl)*	**46.43**	57.94	48.63	73.15	97.17	**51.00**	99.61
Brent crude oil[2]	*(U.S. $/bbl)*	**50.26**	61.92	53.97	76.27	101.85	**55.38**	106.56
Light sweet at Edmonton	*($/bbl)*	**56.23**	67.72	51.93	75.69	97.16	**58.63**	100.87
Western Canadian Select[3]	*(U.S. $/bbl)*	**33.16**	46.35	33.90	58.90	76.99	**37.80**	78.50
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**38.66**	51.31	36.41	61.77	77.96	**42.12**	77.12
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**13.24**	11.49	14.63	14.14	20.23	**13.12**	21.16
Condensate at Edmonton	*(U.S. $/bbl)*	**44.21**	57.94	45.62	70.57	93.45	**49.26**	100.41
NYMEX natural gas[4]	*(U.S. $/mmbtu)*	**2.77**	2.64	2.98	4.00	4.06	**2.80**	4.56
NIT natural gas	*($/GJ)*	**2.65**	2.53	2.80	3.80	4.00	**2.66**	4.32
Chicago Regular Unleaded Gasoline	*(U.S. $/bbl)*	**72.02**	79.43	61.97	80.58	112.71	**71.24**	115.59
Chicago Ultra-low Sulphur Diesel	*(U.S. $/bbl)*	**67.08**	75.89	70.22	101.54	118.56	**71.05**	122.82
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**23.87**	20.30	16.14	14.04	17.41	**20.17**	18.38
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**20.45**	21.70	19.33	16.09	18.86	**20.51**	19.47
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.764**	0.813	0.806	0.881	0.918	**0.794**	0.914
Canadian $ Equivalents[5]								
WTI crude oil	*($/bbl)*	**60.77**	71.27	60.33	83.03	105.85	**64.23**	108.98
Brent crude oil	*($/bbl)*	**65.79**	76.16	66.96	86.57	110.95	**69.75**	116.59
WTI/Lloyd crude blend differential	*($/bbl)*	**17.33**	14.13	18.15	16.05	22.04	**16.52**	23.15
NYMEX natural gas	*($/mmbtu)*	**3.63**	3.25	3.70	4.54	4.42	**3.53**	4.99

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

Crude Oil Benchmarks

The imbalance between global crude oil supply and demand, led primarily by the growth in U.S. unconventional and the Organization of the Petroleum Exporting Countries ("OPEC") production, lower economic growth forecasts from emerging markets and corresponding growth in global crude oil inventories, resulted in the continued weakness of key crude oil benchmarks in the third quarter of 2015.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of West Texas Intermediate ("WTI"), adjusted to Western Canada, while the price received by the Company for crude oil production from the Atlantic and Asia Pacific Regions is primarily driven by the price of Brent. A portion of Husky'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 third quarter of 2015, 60 percent of Husky's crude oil production was heavy crude oil or bitumen compared with 58 percent in the third quarter of 2014.

Husky's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton decreased in the third quarter of 2015 compared to the third quarter of 2014 resulting primarily from increasing diluent pipeline infrastructure, lower expected demand growth from oil sands and declining market benchmarks for energy commodities.

Natural Gas Benchmarks

Average natural gas benchmark prices continued to be weak in the third quarter of 2015 primarily due to the substantial supply of natural gas in North America. The substantial natural gas supply has resulted largely from technological advances in horizontal drilling and hydraulic fracturing which have unlocked significant reserves which were not economical under previously applied extraction methods.

The price received by the Company for natural gas production from Western Canada is primarily driven by the NOVA Inventory Transfer ("NIT") near-month contract price of natural gas while the price received by the Company for production from the Asia Pacific Region is covered by a fixed long-term sales contract.

Natural gas is consumed internally by the Company's Upstream and Downstream operations which reduces the impact of weak natural gas benchmark prices on the Company's results. The Company's internal operations consumed approximately 190 mmcf/day of natural gas during the first nine months of 2015 compared to approximately 180 mmcf/day during the first nine months of 2014.

Refining Benchmarks

The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs nor the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Husky's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. Husky's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards (“IFRS”).

Foreign Exchange

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

In the third quarter and the first nine months of 2015, the Company benefited from the weakening of the Canadian dollar compared to the same periods in 2014. The Canadian dollar averaged U.S. $0.764 and U.S. $0.794 in the third quarter and the first nine months of 2015, respectively, compared to U.S. $0.918 and U.S. $0.914 in the third quarter and first nine months of 2014, respectively.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the third quarter of 2015 on earnings before income taxes and net earnings. The table below reflects what the effect would have been on the financial results for the third quarter of 2015 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the third quarter of 2015. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	**2015 Third 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]	**46.43**	*U.S. $1.00/bbl*	**97**	**0.10**	**72**	**0.07**
NYMEX benchmark natural gas price[5]	**2.77**	*U.S. $0.20/mmbtu*	**25**	**0.03**	**17**	**0.02**
WTI/Lloyd crude blend differential[6]	**13.24**	*U.S. $1.00/bbl*	**(48)**	**(0.05)**	**(33)**	**(0.03)**
Canadian light oil margins	**0.050**	*Cdn $0.005/litre*	**14**	**0.01**	**11**	**0.01**
Asphalt margins	**27.16**	*Cdn $1.00/bbl*	**14**	**0.01**	**10**	**0.01**
New York Harbour 3:2:1 crack spread	**20.45**	*U.S. $1.00/bbl*	**50**	**0.05**	**31**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.764**	*U.S. $0.01*	**(51)**	**(0.05)**	**(38)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 984.1 million common shares outstanding as of September 30, 2015.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Excludes impact on asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

3. Strategic Plan

Husky's strategy is to maintain and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward thermal developments and resource plays, while advancing growth in the Asia Pacific Region, the Oil Sands and the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation and blending of crude oil and natural gas and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company’s Upstream operations are located primarily in Western Canada, offshore the East Coast of Canada, offshore China and offshore Indonesia.

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

4. Key Growth Highlights

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

4.1 Upstream

Heavy Oil

Heavy Oil Thermal Developments

The Company continued to advance its inventory of heavy oil thermal developments. These long-life developments are being built with modular, repeatable designs and are expected to require low sustaining capital once brought online. Total heavy oil thermal production averaged 50,000 bbls/day in the third quarter of 2015 reflecting the early start and ramp up of the Rush Lake development.

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	First Production Expected
Rush Lake	12,000[(1)]	100%	On production
Edam East	10,000	77%	Q2 2016
Vawn	10,000	69%	Q3 2016
Edam West	4,500	60%	Q3 2016

(1) Design capacity for Rush Lake has been revised to include 2,000 bbls/day from the Rush Lake Pilot project.

First oil was achieved at the Rush Lake heavy oil thermal development on July 16, 2015. Production from the development averaged 10,050 bbls/day in the month of September with current rates exceeding its design capacity.

At the 10,000 bbls/day Edam East and 10,000 bbls/day Vawn heavy oil thermal developments, construction is approximately 77 and 69 percent complete, respectively. First production at both heavy oil thermal developments is now expected ahead of schedule in the second quarter of 2016 at Edam East and in the third quarter of 2016 at Vawn.

At the 4,500 bbls/day Edam West heavy oil thermal development, construction is approximately 60 percent complete. First production is now expected ahead of schedule in the third quarter of 2016.

Several other heavy oil thermal projects are in the pre-development phase.

Asia Pacific Region

China

Block 29/26

Combined gross production from the Liwan 3-1 and Liuhua 34-2 gas fields was maintained at 295 mmcf/day and gross sales of associated natural gas liquids were approximately 14.8 mboe/day in the third quarter of 2015. Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, continue to be pursued together with CNOOC Limited.

Offshore Taiwan

Analysis of the two-dimensional seismic survey data acquired in 2014 on the Company's offshore Taiwan block has been completed and a number of significant structures have been identified on the block. The Company plans to acquire three-dimensional seismic survey data on the most attractive structures during 2016 and 2017.

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block. Wellhead platform and pipeline infrastructure construction at the liquids-rich BD field is ongoing and approximately 54 percent complete. The sailout of the platform jacket and topsides took place in October 2015. Construction of the FPSO vessel is approximately 25 percent complete and all major lead time items have been ordered.

The tendering process for the MDA and MBH development projects continued in the third quarter of 2015.

Anugerah

The two-dimensional and three-dimensional seismic survey data acquired during the second quarter of 2015 on the Anugerah contract area continues to be evaluated to determine the potential for future drilling opportunities.

Oil Sands

Sunrise Energy Project

Production continued to ramp up at the Sunrise Energy Project in the third quarter of 2015. Production from the project averaged approximately 10,000 bbls/day (5,000 bbls/day net to Husky) in September 2015 and is expected to ramp up to 60,000 bbls/day (30,000 bbls/day net to Husky) around the end of 2016. Steam operations commenced in early September 2015 at the second of two processing plants. Fifty-five well pairs are being steamed with 36 currently producing bitumen.

Atlantic Region

White Rose Field and Satellite Extensions

Production commenced from the second well at the South White Rose extension ("SWRX") on September 6, 2015. Peak production at the SWRX of 15,000 bbls/day net to Husky on the first two wells was reached in early September.

Drilling of the Hibernia formation well at North Amethyst has been deferred to 2016/2017, subject to rig availability.

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

Atlantic Exploration

An exploration and appraisal drilling program continues at the Bay du Nord discovery in the Flemish Pass Basin. Evaluation of initial results is ongoing.

Western Canada Resource Play Development

Natural Gas Resource Plays

In the third quarter of 2015, seven wells (gross) were drilled and seven wells (gross) were completed in key plays across the natural gas portfolio.

Natural Gas Resource Plays - Drilling and Completion Activity in Key Plays[(1)(2)]

		Three months ended September 30, 2015		Nine months ended September 30, 2015	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	6	2	18	22
Wilrich	Kakwa, Alberta	—	3	4	5
Strachan Cardium	Rocky Mountain House, Alberta	1	2	5	4
Total Gross		7	7	27	31
Total Net		5	5	17	24

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

In the Ansell multi-zone natural gas resource play, six horizontal wells (gross) were drilled and two horizontal wells (gross) were completed in the third quarter of 2015. Average production from the play was approximately 20,000 boe/day in the third quarter of 2015 and was negatively impacted by turnaround activity at third party facilities and pipeline restrictions.

Development continued on the Strachan liquids-rich natural gas resource play near Rocky Mountain house with one well (gross) drilled and two wells (gross) completed in the third quarter of 2015. Production results from the play are in line with expectations.

Oil Resource Plays and Conventional

Oil related drilling and completion activity in Western Canada has been substantially curtailed.

Infrastructure and Marketing

Construction is ongoing for the expansion of the South Saskatchewan Gathering System which will create incremental capacity to accommodate production from the Rush Lake, Edam East, Vawn and Edam West thermal developments. Construction is now more than three quarters complete.

In order to maintain market flexibility, the Company continued expanding its pumping capacity in the third quarter of 2015 at the Hardisty terminal to meet the new requirements of the Enbridge Clipper pipeline. Expansion work is expected to be completed in the fourth quarter of 2015.

4.2 Downstream

Canadian Refined Products

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

BP-Husky Toledo, Ohio Refinery

The Company continued construction in the third quarter of 2015 to address updated flare stack regulatory monitoring and emission standards and expects work to be completed prior to the new standards coming into effect in the fourth quarter of 2015.

5. Results of Operations

5.1 Upstream

Total Upstream net earnings (loss) include results from both the Exploration and Production and Infrastructure and Marketing operations. Net earnings (loss) on a combined basis reflect weaker Exploration and Production earnings compared to the same period in 2014 primarily due to impairment charges, higher exploration and evaluation expenses, lower realized crude oil prices and lower crude oil production in Western Canada and the Atlantic Region. The decreases were partially offset by lower royalties, lower operating costs and a weaker Canadian dollar.

Exploration and Production

Exploration and Production Earnings (Loss) Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2015**	2014	**2015**	2014
Gross revenues	**1,253**	2,210	**4,185**	6,744
Royalties	**(83)**	(260)	**(347)**	(852)
Revenues, net of royalties	**1,170**	1,950	**3,838**	5,892
Purchases, operating, transportation and administrative expenses	**578**	663	**1,766**	1,939
Depletion, depreciation, amortization and impairment	**5,920**	671	**7,352**	1,881
Exploration and evaluation expenses	**308**	42	**408**	101
Other expenses (income)	**(13)**	(8)	**74**	135
Provisions for (recovery of) income taxes	**(1,520)**	146	**(1,558)**	470
Net earnings (loss)	**(4,103)**	436	**(4,204)**	1,366

Third Quarter

Exploration and Production net loss of $4,103 million in the third quarter of 2015 included an after-tax impairment charge of $3,824 million and an after-tax exploration and evaluation asset write-down of $167 million. The after-tax impairment charge was recognized on crude oil and natural gas assets located in Western Canada and was the result of sustained declines in forecasted short and long-term crude oil and natural gas prices and management's plan to reduce capital investment in these areas. Excluding the after-tax impairment charge and write-down of exploration and evaluation assets, the decrease in net earnings was primarily due to lower realized crude oil prices resulting from continued weakness in global crude oil benchmark prices and lower crude oil production in Western Canada and the Atlantic Region. The decreases were partially offset by lower royalties, lower operating costs and a weaker Canadian dollar.

Production decreased by 8.1 mboe/day to 333.0 mboe/day in the third quarter of 2015 compared to 341.1 mboe/day in the third quarter of 2014. The decrease in Western Canada was primarily due to natural reservoir declines at mature crude oil properties and the decrease in the Atlantic Region was primarily due to natural reservoir declines at mature fields. The decreases were partially offset by new production from the Rush Lake heavy oil thermal development, new production from the South White Rose extension, production ramp up from the Sunrise Energy Project, higher production from Wenchang in the Asia Pacific Region and strong production performance from the Tucker thermal development.

The average realized price for crude oil, NGL and bitumen in the third quarter of 2015 was $41.92/bbl compared to $83.73/bbl during the same period in 2014, a decrease of 50 percent, due to significantly lower crude oil benchmark prices partially offset by a weaker Canadian dollar. Realized natural gas prices averaged $5.76/mcf in the third quarter of 2015 compared to $6.11/mcf in the same period in 2014, a decrease of six percent, primarily due to lower natural gas benchmarks in North America.

Nine Months

Exploration and Production net loss of $4,204 million in the first nine months of 2015 included an after-tax impairment charge of $3,824 million and an exploration and evaluation asset write-down of $171 million. Excluding the after-tax impairment charge and write-down of exploration and evaluation assets, the decrease was primarily due to the same factors which impacted the third quarter. During the first nine months of 2015, the average realized price for crude oil, NGL and bitumen was $47.21/bbl compared to $87.11/bbl in the same period in 2014, a decrease of 46 percent. During the first nine months of 2015, the average realized natural gas price was $5.94/mcf comparable to $5.84/mcf in the same period in 2014.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended Sept. 30, 2015	2014	Nine months ended Sept. 30, 2015	2014
Crude oil and NGL *($/bbl)*				
Light crude oil & NGL	**54.96**	96.47	**60.50**	105.97
Medium crude oil	**41.16**	83.35	**46.16**	85.52
Heavy crude oil	**36.51**	77.29	**39.86**	76.36
Bitumen	**33.86**	75.50	**38.50**	74.84
Total crude oil and NGL average	**41.92**	83.73	**47.21**	87.11
Natural gas average *($/mcf)*	**5.76**	6.11	**5.94**	5.84
Total average *($/boe)*	**39.45**	68.35	**43.23**	71.71

The price realized for Western Canada crude oil reflected lower WTI prices partially offset by a weaker Canadian dollar. The price realized for offshore production is based on Brent prices. Realized natural gas prices in the third quarter of 2015 reflect lower natural gas benchmark prices in North America partially offset by favourable contract prices received at the Liwan Gas Project when compared to the same period in 2014.

Daily Gross Production

Daily Gross Production	Three months ended Sept. 30, 2015	2014	Nine months ended Sept. 30, 2015	2014
Crude Oil and NGL *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**25.7**	30.3	**27.8**	29.8
Medium crude oil	**17.7**	20.2	**18.2**	22.1
Heavy crude oil	**67.9**	76.1	**70.0**	76.5
Bitumen[1]	**63.0**	56.2	**55.6**	54.3
	174.3	182.8	**171.6**	182.7
Oil Sands				
Sunrise - bitumen	**3.7**	—	**1.9**	—
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**26.1**	33.3	**29.8**	39.7
Terra Nova – light crude oil	**3.5**	4.0	**4.8**	5.3
	29.6	37.3	**34.6**	45.0
Asia Pacific Region				
Wenchang – light crude oil & NGL	**7.7**	2.8	**7.8**	3.9
Liwan - NGL[2]	**8.1**	6.5	**9.6**	3.0
	15.8	9.3	**17.4**	6.9
	223.4	229.4	**225.5**	234.6
Natural gas *(mmcf/day)*				
Western Canada	**505.0**	509.3	**515.9**	502.0
Asia Pacific Region[2]	**152.7**	161.0	**182.6**	91.9
	657.7	670.3	**698.5**	593.9
Total *(mboe/day)*	**333.0**	341.1	**341.9**	333.6

(1) *Bitumen production includes heavy oil thermal average daily gross production of 50.0 mbbls/day for the three months ended September 30, 2015 compared to 45.4 mbbls/day for the three months ended September 30, 2014.*

(2) *Reported production volumes include Husky's net working interest production from the Liwan Gas Project (49 percent) and an incremental share of production volumes allocated to Husky for exploration cost recoveries. The incremental share of production volumes ceased during the second quarter of 2015 reflecting the completion of cost recoveries.*

Crude Oil and NGL Production

Third Quarter

Crude oil and NGL production decreased in the third quarter of 2015 by 6.0 mbbls/day compared to the same period in 2014 due to lower production in Western Canada and the Atlantic Region. In Western Canada, crude oil production decreased due to natural reservoir declines at mature properties and higher turnaround activity combined with reduced capital investment in a low commodity price environment. In the Atlantic Region, crude oil production decreased primarily due to natural reservoir declines at mature fields. The decreases were partially offset by new production from the Rush Lake heavy oil thermal development and from the South White Rose extension, production ramp up at the Sunrise Energy Project which began producing in the first quarter of 2015, higher production from Wenchang where a planned turnaround on the FPSO vessel offstation impacted production in the third quarter of 2014 and strong production performance from the Tucker thermal development.

Nine Months

Crude oil and NGL production decreased in the first nine months of 2015 by 9.1 mbbls/day compared to the same period in 2014 primarily due to the same factors which impacted the third quarter partially offset by higher NGL production from the Liwan Gas Project where production commenced at the end of the first quarter of 2014.

Natural Gas Production

Third Quarter

Natural gas production decreased in the third quarter of 2015 by 12.6 mmcf/day compared to the same period in 2014 primarily due to lower production from the Asia Pacific Region. The Company's entitlement share of production volumes at the Liwan Gas Project reverted back to 49 percent in late May 2015 following the completion of exploration cost recoveries. The decrease was partially offset by an increase in gross production volumes at the Liwan Gas Project in the third quarter of 2015 compared to the same period in 2014.

Nine Months

Natural gas production increased in the first nine months of 2015 by 104.6 mmcf/day compared to the same period in 2014. The increase was primarily attributable to higher production from the Liwan Gas Project, where production began at the end of the first quarter of 2014, and from higher natural gas resource play production in Western Canada.

2015 Production Guidance

The following table shows actual daily production for the nine months ended September 30, 2015 and the year ended December 31, 2014, as well as the previously issued production guidance for 2015.

		Actual Production	
	2015 Guidance	**Nine months ended September 30, 2015**	Year ended December 31, 2014
Canada			
Light / Medium crude oil & NGL *(mbbls/day)*	87 - 92	**81**	96
Heavy crude oil & bitumen *(mbbls/day)*	125 - 135	**127**	131
Natural gas *(mmcf/day)*	440 - 480	**516**	507
Canada total *(mboe/day)*	285 - 307	**294**	312
Asia Pacific			
Light crude oil & NGL *(mbbls/day)*	13 - 15	**17**	9
Natural gas *(mmcf/day)*	160 - 195	**183**	114
Asia Pacific total *(mboe/day)*	40 - 48	**48**	28
Total *(mboe/day)*	325 - 355	**342**	340

Royalties

Third Quarter

In the third quarter of 2015, royalty rates as a percentage of gross revenues averaged 7 percent compared to 12 percent in the same period in 2014. Royalty rates in Western Canada averaged 8 percent in the third quarter of 2015 compared to 12 percent in the same period in 2014 primarily due to lower commodity prices with a sliding scale price sensitivity rate. Royalty rates for the Atlantic Region averaged 7 percent in the third quarter of 2015 compared to 17 percent in the same period in 2014 primarily due to lower production, lower crude oil prices and higher eligible royalty costs in the third quarter of 2015. Royalty rates in the Asia Pacific Region averaged 5 percent in the third quarter of 2015 compared to 7 percent in the same period in 2014 primarily due to lower crude oil prices which resulted in lower levies on production from Wenchang.

Nine Months

Royalty rates averaged 9 percent of gross revenues in the first nine months of 2015 compared to 13 percent in the same period in 2014. Royalty rates in Western Canada averaged 9 percent in the first nine months of 2015 compared to 12 percent in the first nine months of 2014 due to the same factors which impacted the third quarter of 2015. Royalty rates for the Atlantic Region averaged 12 percent in the first nine months of 2015 compared to 19 percent in the same period in 2014 primarily due to the same factors which impacted the the third quarter of 2015. Royalty rates in the Asia Pacific Region averaged 5 percent in the first nine months of 2015 compared to 9 percent in the same period in 2014 due to lower royalty rates associated with production from the Liwan Gas Project combined with the same factors which impacted the third quarter of 2015.

Operating Costs

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2015**	2014	**2015**	2014
Western Canada	**422**	456	**1,269**	1,382
Atlantic Region	**57**	62	**164**	164
Asia Pacific	**25**	30	**74**	48
Total	**504**	548	**1,507**	1,594
Unit operating costs ($/boe)	**15.52**	16.61	**15.36**	16.48

Third Quarter

Total Exploration and Production operating costs in the third quarter of 2015 were $504 million compared to $548 million in the same period in 2014. Total unit operating costs averaged $15.52/boe in the third quarter of 2015 compared to $16.61/boe in the same period in 2014.

Unit operating costs in Western Canada averaged $16.33/boe in the third quarter of 2015 compared to $17.44/boe in the same period in 2014. The decrease in unit operating costs per boe was primarily attributable to cost savings initiatives and lower energy costs.

Unit operating costs in the Atlantic Region averaged $20.94/boe in the third quarter of 2015 compared to $17.86/boe in the same period in 2014. The increase in unit operating costs per boe was primarily attributable to lower production volumes.

Unit operating costs in the Asia Pacific Region averaged $6.52/boe in the third quarter of 2015 compared to $9.38/boe in the same period in 2014. The decrease in unit operating costs per boe was primarily attributable to lower insurance, chemical and helicopter costs at the Liwan Gas Project in the third quarter of 2015 combined with the Wenchang FPSO vessel offstation turnaround activity in the third quarter of 2014.

Nine Months

Total Exploration and Production operating costs in the first nine months of 2015 were $1,507 million compared to $1,594 million in the same period in 2014. Total unit operating costs in the first nine months of 2015 averaged $15.36/boe compared to $16.48/boe in the same period in 2014.

Unit operating costs in Western Canada averaged $16.89/boe in the first nine months of 2015 compared to $17.71/boe in the same period in 2014. The decrease in unit operating costs was primarily attributable to the same factors which impacted the third quarter.

Unit operating costs in the Atlantic Region averaged $17.38/boe in the first nine months of 2015 compared to $13.33/boe in the same period in 2014. The increase in unit operating costs was primarily attributable to insurance recoveries received in the second quarter of 2014 combined with the same factors which impacted the third quarter.

Unit operating costs in the Asia Pacific Region averaged $5.66/boe in the first nine months of 2015 compared to $7.97/boe in the same period in 2014. The decrease was primarily attributable to lower unit cost production from the Liwan Gas Project which commenced at the end of the first quarter of 2014 combined with the same factors which impacted the third quarter.

Exploration and Evaluation Expenses

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2015**	2014	**2015**	2014
Seismic, geological and geophysical	**27**	37	**78**	79
Expensed drilling	**246**	1	**285**	14
Expensed land	**35**	4	**45**	8
Exploration and evaluation expenses	**308**	42	**408**	101

Third Quarter

Exploration and evaluation expenses in the third quarter of 2015 were $308 million compared to $42 million in the third quarter of 2014. The increase in expensed drilling and land costs was primarily attributable to a $277 million write-down of certain Western Canada resource play assets including associated unfulfilled work commitment penalties. The write-down was the result of management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices.

Nine Months

Exploration and evaluation expenses in the first nine months of 2015 were $408 million compared to $101 million in the same period of 2014. The increase in expensed drilling and land costs was primarily attributable to same factors which impacted the third quarter in addition to the expensed Aster exploration well in the Atlantic Region during the first quarter of 2015.

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

Third Quarter

During the third quarter of 2015, the Company recognized a pre-tax impairment charge of $5,181 million on crude oil and natural gas assets, including associated goodwill, located in Western Canada. The impairment charge was the result of sustained declines in forecasted short and long-term crude oil and natural gas prices and management's plan to reduce capital investment in these areas.

In the third quarter of 2015, total DD&A excluding impairment averaged $24.13/boe compared to $21.36/boe in the third quarter of 2014. The increase was primarily due to the derecognition of approximately $46 million pre-tax of assets related to the cancellation of the West Mira drilling rig contract.

Nine Months

In the first nine months of 2015, total DD&A excluding impairment averaged $23.25/boe compared to $20.64/boe in the same period of 2014. The increase was primarily attributable to higher depletion rates on production from the Liwan Gas Project which began producing at the end of the first quarter of 2014 combined with the same factors which impacted the third quarter.

Exploration and Production Capital Expenditures

In the first nine months of 2015, Upstream Exploration and Production capital expenditures were $1,906 million. Capital expenditures were $338 million (18 percent) in Western Canada conventional and resource plays, $760 million (40 percent) in Heavy Oil, $237 million (12 percent) in Oil Sands, $510 million (27 percent) in the Atlantic Region and $61 million (three percent) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1]	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2015**	2014	**2015**	2014
Exploration				
Western Canada[2]	**9**	40	**22**	145
Heavy Oil[2]	**—**	—	**8**	25
Oil Sands[2]	**—**	2	**—**	7
Atlantic Region	**51**	12	**155**	34
Asia Pacific Region	**2**	2	**3**	11
	62	56	**188**	222
Development				
Western Canada[2]	**87**	175	**314**	743
Heavy Oil[2]	**212**	301	**701**	825
Oil Sands[2]	**54**	183	**237**	430
Atlantic Region	**125**	201	**355**	445
Asia Pacific Region	**12**	139	**58**	368
	490	999	**1,665**	2,811
Acquisitions				
Western Canada[2]	**1**	1	**2**	2
Heavy Oil[2]	**50**	14	**51**	18
	603	1,070	**1,906**	3,053

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *During the second quarter of 2015, the Company reclassified capital expenditures to Heavy Oil, previously classified as part of Western Canada and Oil Sands.*

Western Canada

During the first nine months of 2015, $338 million was invested in Western Canada conventional and resource plays, compared to $890 million in the same period in 2014, primarily on the development of the Company's natural gas resource plays including the Ansell multi-zone, Strachan Cardium and Wilrich projects.

Heavy Oil

During the first nine months of 2015, $760 million was invested in Heavy Oil, compared to $868 million in the same period in 2014, primarily on the development of the Company's heavy oil thermal developments including the Rush Lake, Edam East, Edam West and Vawn developments.

Oil Sands

During the first nine months of 2015, $237 million was invested in Oil Sands projects, compared to $437 million in the same period in 2014, primarily on development of Phase 1 of the Sunrise Energy Project.

Atlantic Region

During the first nine months of 2015, $510 million was invested in Atlantic Region projects, compared to $479 million in the same period in 2014, primarily on the continued development of the White Rose extension projects, including the North Amethyst, West White Rose and South White Rose extension satellite fields and on the Bay du Nord discovery in the Flemish Pass Basin.

Asia Pacific Region

During the first nine months of 2015, $61 million was invested in Asia Pacific Region projects, compared to $379 million in the same period of 2014 primarily on the development of the Liwan Gas Project and the shallow water gas developments in the Madura Strait.

Exploration and Production Wells Drilled

Onshore drilling activity

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

	Three months ended Sept. 30,				Nine months ended Sept. 30,			
Wells Drilled [(1)]		**2015**		2014		**2015**		2014
(wells)	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**—**	**—**	4	1	**5**	**4**	52	45
Gas	**2**	**1**	1	1	**4**	**1**	6	4
Dry	**1**	**1**	—	—	**1**	**1**	—	—
	3	**2**	5	2	**10**	**6**	58	49
Development								
Oil	**20**	**20**	153	132	**107**	**92**	370	326
Gas	**6**	**3**	27	25	**28**	**18**	69	60
Dry	**—**	**—**	1	1	**—**	**—**	1	1
	26	**23**	181	158	**135**	**110**	440	387
Total	**29**	**25**	186	160	**145**	**116**	498	436

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

The Company drilled 116 net wells in the Western Canada conventional and resource plays, Heavy Oil and Oil Sands business units in the first nine months of 2015 resulting in 96 net oil wells and 19 net natural gas wells compared to 436 net wells resulting in 371 net oil wells and 64 net natural gas wells in the same period of 2014.

Offshore drilling activity

The following table discloses Husky's offshore Atlantic and Asia Pacific Region drilling activity during the first nine months of 2015:

Region	**Well**	**Working Interest**	**Well Type**
Atlantic Region	Bay du Nord P-78	WI 35 percent	Exploration
Atlantic Region	Bay du Nord L-76	WI 35 percent	Exploration
Atlantic Region	Bay du Nord L-76Z	WI 35 percent	Exploration
Atlantic Region	Aster C-93A[(1)]	WI 40 percent	Exploration
Atlantic Region	Bay d'Espoir B-09	WI 35 percent	Exploration
Atlantic Region	White Rose J-05 3	WI 68.875 percent	Development
Atlantic Region	White Rose J-05 2	WI 72.5 percent	Development
Asia Pacific Region	Wenchang 13-1A4H2	WI 40 percent	Development

(1) *The Aster well was fully written off in the first quarter of 2015 as the well did not encounter economic quantities of hydrocarbons.*

Upstream Planned Turnarounds

- A three week turnaround at the Ram River plant is scheduled for June 2016 and is expected to impact production by approximately 2,400 bbls/day in the second quarter of 2016.
- Other scheduled turnarounds in Western Canada are expected to impact production by approximately 3,000 bbls/day in the second and third quarters of 2016.

Infrastructure and Marketing

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

Infrastructure and Marketing Earnings Summary	Three months ended Sept 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Infrastructure gross margin	**33**	36	**99**	112
Marketing and other gross margin	**23**	11	**48**	48
Gross margin	**56**	47	**147**	160
Operating and administrative expenses	**9**	10	**30**	27
Depreciation and amortization	**6**	6	**17**	19
Other income	**(4)**	(1)	**(2)**	(1)
Provisions for income taxes	**13**	8	**28**	29
Net earnings	**32**	24	**74**	86
Commodity volumes managed *(mboe/day)* [(1)]	**116.2**	138.5	**140.8**	144.8

[(1)] *Commodity volumes managed was revised in the third quarter of 2015 to exclude hedged volumes and now represents physical volumes managed only. Prior periods have been revised to conform with the current period presentation.*

Third Quarter

Infrastructure and Marketing net earnings in the third quarter of 2015 increased by $8 million compared to the same period in 2014 resulting primarily from declining crude oil prices at the end of the quarter which led to unrealized mark to market gains on forward crude oil contracts.

Nine Months

Infrastructure and Marketing net earnings in the first nine months of 2015 decreased by $12 million compared to the same period in 2014 primarily due to lower pipeline revenue in a weak commodity price environment.

Infrastructure and Marketing Capital Expenditures

In the first nine months of 2015, Infrastructure and Marketing capital expenditures totalled $126 million compared to $113 million in 2014 primarily related to the expansion of the South Saskatchewan Gathering System into Lloydminster.

5.2 Downstream

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing. The decrease in Upgrader net earnings (loss) was primarily due to lower throughput and lower sales volumes resulting from unplanned maintenance that temporarily suspended operations in the third quarter of 2015. The increase in Canadian Refined Products was primarily due to strong contract pricing and lower feedstock costs at the Lloydminster Refinery partially offset by lower realized product pricing and higher feedstock costs at the Lloydminister and Minnedosa Ethanol plants. The increase in U.S. Refining and Marketing net earnings was primarily due to higher Chicago 3:2:1 market crack spreads, a weaker Canadian dollar and accrued insurance recoveries partially offset by FIFO losses and lower throughput at the Lima Refinery.

Upgrader

Upgrader Earnings (loss) Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Gross revenues	**190**	604	**955**	1,737
Gross margin	**28**	113	**245**	441
Operating and administrative expenses	**41**	45	**128**	139
Depreciation and amortization	**26**	27	**78**	79
Other expenses (income)	**—**	—	**(11)**	9
Provisions for (recovery of) income taxes	**(10)**	10	**14**	55
Net earnings (loss)	**(29)**	31	**36**	159
Upgrader throughput *(mbbls/day)*(1)	**44.2**	73.9	**66.0**	71.5
Total sales *(mbbls/day)*(2)	**42.5**	76.3	**65.4**	71.5
Synthetic crude oil sales *(mbbls/day)*	**31.6**	56.1	**48.3**	52.7
Upgrading differential *($/bbl)*	**17.58**	19.98	**17.47**	23.99
Unit margin *($/bbl)*(2)	**7.16**	16.10	**13.72**	22.59
Unit operating cost *($/bbl)*(3)	**9.84**	6.18	**6.94**	6.76

(1) *Throughput includes diluent returned to the field.*
(2) *Unit margin was revised in the first quarter of 2015 to reflect total sales volumes. Prior periods have been adjusted to conform to current period presentation.*
(3) *Based on throughput.*

Third Quarter

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

Upgrader net earnings (loss) decreased by $60 million in the third quarter of 2015 compared to the same period in 2014 primarily due to lower throughput, lower sales volumes and higher unit operating costs resulting from unplanned maintenance to the facility's coke drums that suspended operations for approximately eight weeks during the third quarter of 2015. In addition, the upgrading differential was lower in the third quarter of 2015 compared to the third quarter of 2014.

During the third quarter of 2015, the upgrading differential averaged $17.58/bbl, a decrease of $2.40/bbl or 12 percent compared to the same period in 2014. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in the upgrading differential was attributable to lower realized prices for Husky Synthetic Blend partially offset by lower heavy oil feedstock costs. The average price for Husky Synthetic Blend in the third quarter of 2015 was $59.40/bbl compared to $106.80/bbl in the same period in 2014.

Nine Months

Upgrader net earnings for the first nine months of 2015 decreased by $123 million compared to the same period in 2014 primarily due to the same factors which impacted the third quarter. The average price for Husky Synthetic Blend in the first nine months of 2015 was $62.95/bbl compared to $108.62/bbl in the same period in 2014.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Gross revenues	**839**	1,145	**2,187**	3,075
Gross margin				
Fuel	**40**	45	**106**	110
Refining	**36**	57	**102**	202
Asphalt	**92**	64	**198**	183
Ancillary	**16**	15	**44**	43
	184	181	**450**	538
Operating and administrative expenses	**64**	76	**206**	226
Depreciation and amortization	**26**	26	**77**	75
Other expenses	**—**	2	**2**	4
Provisions for income taxes	**25**	20	**44**	60
Net earnings	**69**	57	**121**	173
Number of fuel outlets(1)	**486**	502	**487**	502
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**7.7**	8.5	**7.6**	8.0
Fuel sales per retail outlet *(thousands of litres/day)*	**13.2**	13.7	**12.7**	13.2
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**11.0**	11.7	**10.5**	11.7
Lloydminster Refinery *(mbbls/day)*	**26.4**	28.3	**28.0**	28.8
Ethanol production *(thousands of litres/day)*	**814.2**	768.1	**785.8**	779.5

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

Third Quarter

Asphalt gross margins were higher in the third quarter of 2015 compared to the same period in 2014 primarily due to strong contract pricing and lower feedstock costs partially offset by lower throughput resulting from unplanned maintenance completed in the quarter.

Refining gross margins were lower in the third quarter of 2015 compared to the same period in 2014 primarily due to lower realized product pricing and higher feedstock costs at the Lloydminister and Minnedosa Ethanol plants.

Fuel gross margins were lower in the third quarter of 2015 compared to the same period in 2014 primarily due to lower commercial demand caused by decreased oil and gas drilling activity.

Nine Months

Refining gross margins were lower due to an unplanned outage at the Prince George Refinery in the second quarter of 2015 which resulted in lower throughput and the need to purchase finished products from third parties to deliver on committed sales volumes in addition to the factors which impacted the third quarter.

Asphalt gross margins were higher due to the same factors which impacted the third quarter partially offset by lower margins in the first quarter of 2015 due to reduced drilling activity in Western Canada which led to lower demand and sales prices for drilling fluids.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Gross revenues	**1,973**	2,811	**5,653**	8,159
Gross refining margin	**189**	240	**781**	873
Operating and administrative expenses	**122**	116	**362**	358
Depreciation and amortization	**74**	77	**257**	200
Other expenses (income)	**(65)**	1	**(154)**	2
Provisions for (recovery of) income taxes	**22**	17	**(86)**	116
Net earnings	**36**	29	**402**	197
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**142.9**	156.0	**133.1**	134.3
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**66.4**	64.2	**63.0**	63.0
Refining margin *(U.S. $/bbl crude throughput)*	**8.10**	11.42	**12.10**	15.26
Refinery inventory *(mmbbls)*(1)	**12.5**	11.3	**12.5**	11.3

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

Third Quarter

U.S. Refining and Marketing net earnings were $36 million in the third quarter of 2015 compared to $29 million in the same period in 2014. The impact of higher Chicago 3:2:1 market crack spreads with a weaker Canadian dollar was offset by FIFO losses and lower throughput volumes at the Lima Refinery which continued to be negatively impacted by unplanned outages in the isocracker unit in January 2015 and in the coker unit in September 2015. During the third quarter of 2015, the Company recorded business interruption loss and property damage insurance recoveries associated with the isocracker fire of $64 million which is reflected in other expenses (income).

The Chicago 3:2:1 market crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter. The FIFO impact was a decrease in net earnings of approximately $127 million in the third quarter of 2015 compared to a decrease in net earnings of approximately $28 million in the same period in 2014. In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10 to 15 percent of other products which are sold at discounted market prices compared to gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Nine Months

Net earnings in the first nine months of 2015 increased by $205 million compared to the same period in 2014 primarily due to a $203 million deferred income tax recovery recognized in the first quarter of 2015 related to the partial payment of the contribution payable to BP-Husky Refining LLC, higher Chicago 3:2:1 market crack spreads and a weaker Canadian dollar. The increases were partially offset by FIFO losses in realized refining margins. During the first nine months of 2015, the Company wrote-off $46 million of the carrying value of the isocracker unit which is included in depreciation and amortization. Total business interruption loss and property damage insurance recoveries of $156 million associated with the isocracker unit fire have been recorded during the first nine months of 2015.

Downstream Capital Expenditures

In the first nine months of 2015, Downstream capital expenditures totalled $293 million compared to $347 million in the same period in 2014. In Canada, capital expenditures of $50 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. At the Lima Refinery, $178 million was spent primarily on various reliability and environmental initiatives in addition to the repair of the isocracker unit. At the BP-Husky Toledo Refinery, capital expenditures totalled $65 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Turnarounds

- A large maintenance turnaround has been scheduled at the Toledo Refinery starting in the second quarter of 2016.
- A six to eight-week maintenance turnaround has been scheduled at the Lima Refinery starting in the second quarter of 2016. The isocracker is expected to resume operations at the same time as the Refinery startup.

5.3 Corporate

Corporate Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions) income (expense)	**2015**	2014	**2015**	2014
Administrative expenses	**5**	(16)	**(45)**	(46)
Stock-based compensation	**10**	51	**24**	(2)
Depreciation and amortization	**(22)**	(18)	**(62)**	(52)
Other - net	**3**	(4)	**3**	5
Net foreign exchange gain (loss)	**(14)**	31	**54**	46
Finance expense	**(45)**	(21)	**(93)**	(48)
Provisions for (recovery of) income taxes	**(34)**	(29)	**(91)**	(23)
Net loss	**(97)**	(6)	**(210)**	(120)

Third Quarter

The Corporate segment reported a net loss of $97 million in the third quarter of 2015 compared to a net loss of $6 million in the same period in 2014. Foreign exchange expense increased by $45 million due to a weakening of the Canadian dollar against the U.S. dollar which impacted the translation of the Company's foreign currency denominated working capital. Finance expense increased by $24 million due to higher debt and a decrease in the amount of capitalized interest. The Company recognized a stock-based compensation recovery of $10 million and $51 million in the third quarter of 2015 and 2014, respectively, due to declines in the Company's share price. The stock-based compensation recovery was lower in the third quarter of 2015 as a significant portion of the Company's stock-based compensation liability was reversed in previous quarters. At September 30, 2015 and 2014 the Company's stock-based compensation liability was $33 million and $99 million, respectively. Administrative expenses decreased by $21 million in the third quarter of 2015 compared to the same period in 2014 primarily due to a recovery on the release of a long-term insurance liability partially offset by the reclassification of early invoice payment discounts to the Company's Upstream and Downstream segments.

Nine Months

In the first nine months of 2015, the Corporate segment reported a loss of $210 million compared to a loss of $120 million in the same period of 2014. Stock-based compensation recovery increased due to a significant decrease in the Company's share price in the first nine months of 2015. Finance expense increased by $45 million due to the same factors which impacted the third quarter.

Foreign Exchange Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2015**	2014	**2015**	2014
Gain (loss) on translation of U.S. dollar denominated long-term debt	**(12)**	(11)	**(34)**	17
Gain on contribution receivable	**—**	—	**—**	7
Gain on non-cash working capital	**9**	25	**28**	25
Other foreign exchange gain (loss)	**(11)**	17	**60**	(3)
Net foreign exchange gain (loss)	**(14)**	31	**54**	46
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S $0.802**	U.S. $0.937	**U.S $0.862**	U.S. $0.940
At end of period	**U.S $0.747**	U.S. $0.892	**U.S $0.747**	U.S. $0.892

Included in other foreign exchange gain (loss) are realized and unrealized foreign exchange gains and losses on working capital and intercompany financing. The foreign exchange gains (losses) on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period.

Corporate Capital Expenditures

In the first nine months of 2015, Corporate capital expenditures were $54 million compared to $91 million in the same period of 2014 and were primarily related to computer hardware and software and leasehold improvements.

Consolidated Income Taxes

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2015**	2014	**2015**	2014
Provisions for (recovery of) income taxes	**(1,436)**	230	**(1,467)**	753
Income taxes paid	**50**	145	**196**	526

Third Quarter

Consolidated income taxes were a recovery of $1,436 million in the third quarter of 2015 compared to an expense of $230 million in the same period in 2014. The decrease in consolidated income taxes was primarily due to a $1,357 million deferred income tax recovery associated with impairment charge recognized on crude oil and natural gas assets located in Western Canada.

Nine Months

Consolidated income taxes were a recovery of $1,467 million in the first nine months of 2015 compared to income tax expense of $753 million in the same period in 2014. The decrease in consolidated income taxes was primarily due to the same factors which impacted the third quarter combined with a future income tax recovery from the distribution of U.S. $1.0 billion by BP-Husky Refining LLC to each member following the partial payment of the contribution payable by the Company in the first quarter of 2015. The decreases were partially offset by the recognition of a $157 million deferred income tax expense related to the increase in Alberta provincial tax rates in the second quarter of 2015.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the third quarter of 2015, Husky funded its capital programs and dividend payments through cash generated from operating activities, cash on hand, the issuance of commercial paper and direct borrowings against committed credit facilities and operating facilities. At September 30, 2015, Husky had net debt of $6,842 million compared to $4,025 million of net debt at December 31, 2014. At September 30, 2015, the Company had $2,997 million of unused credit facilities of which $2,632 million are long-term committed credit facilities and $365 million are short-term uncommitted credit facilities. In addition, the Company had $1.90 billion in unused capacity under its February 2015 Canadian universal short form base shelf prospectus (the "Canadian Shelf Prospectus") and U.S. $2.25 billion in unused capacity under its October 2013 U.S. universal short form base shelf prospectus (the "U.S. Shelf Prospectus"). The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions at the time of sale. Refer to Section 6.2.

Cash Flow Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except ratios)	**2015**	2014	**2015**	2014
Cash flow				
Operating activities	**703**	1,518	**2,469**	4,001
Financing activities	**72**	292	**354**	(211)
Investing activities	**(956)**	(968)	**(4,169)**	(3,979)

Cash Flow from Operating Activities

Third Quarter

In the third quarter of 2015, cash flow generated from operating activities was $703 million compared to $1,518 million in the same period in 2014. The decrease in cash flow generated from operating activities was primarily due to lower realized crude oil prices and from the impact of changes in non-cash working capital in the third quarter of 2015 partially offset by lower cash taxes paid.

Nine Months

In the first nine months of 2015, cash flow generated from operating activities was $2,469 million compared to $4,001 million in the same period in 2014. The decrease was primarily due to the same factors which impacted the third quarter.

Cash Flow from (used for) Financing Activities

Third Quarter

In the third quarter of 2015, cash flow generated from financing activities was $72 million compared to cash flow generated from financing activities of $292 million in the same period in 2014. The decrease was primarily due to the repayment of $149 million in commercial paper in the third quarter of 2015 versus the issuance of $600 million in commercial paper in the third quarter of 2014, partially offset by the draw-down of $55 million from the Company's operating facilities and $649 million from the Company's syndicated credit facilities in the third quarter of 2015.

Nine Months

Cash flow generated from financing activities was $354 million in the first nine months of 2015 compared to cash flow used for financing of $211 million in the same period in 2014. The increase in cash flow generated from financing activities was primarily due to the issuance of $750 million of unsecured notes and the issuance of $350 million in total of Cumulative Redeemable Preferred Shares, Series 5 ("Series 5 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 7 ("Series 7 Preferred Shares") in the first half of 2015, partially offset by the same factors which impacted the third quarter of 2015.

Cash Flow used for Investing Activities

Third Quarter

In the third quarter of 2015, cash flow used for investing activities was $956 million compared to $968 million in the same period in 2014. The increase was primarily due to increased restricted cash reserves for future remediation costs of $107 million and from the impact of changes in non-cash working capital in the third quarter of 2015 partially offset by a reduction in capital expenditures during the third quarter of 2015.

Nine Months

Cash flow used for investing activities was $4,169 million in the first nine months of 2015 compared to $3,979 million in the first nine months of 2014. The increase was primarily due to the payment of $1.3 billion of the Company's BP-Husky Refining LLC contribution payable in the first quarter of 2015 partially offset by a reduction in capital expenditures in the first nine months of 2015.

6.2 Sources of Capital

Husky funds its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, cash on hand, the issuance of long-term debt, borrowings under committed and uncommitted credit facilities, the issuance of short-term commercial paper and the issuance of equity. The Company also maintains access to sufficient capital via debt and equity markets commensurate with its balance sheet. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility. At September 30, 2015, the Company's debt to capital employed was 28.9 percent (December 31, 2014 - 20.5 percent). Debt to capital employed constitutes a non-GAAP measure. Refer to Section 11.

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2015, working capital deficiency was $380 million compared to a working capital deficiency of $1,314 million at December 31, 2014. The increase in working capital was mainly attributable to the payment of $1.3 billion of the Company's BP-Husky Refining LLC contribution payable in the first quarter of 2015 partially funded by the issuance of the Series 5 Preferred Shares.

At September 30, 2015, Husky had unused short and long-term credit facilities totalling $2,997 million. A total of $204 million of the Company's short-term credit facilities was used in support of outstanding letters of credit, and $718 million of the Company's long-term borrowing credit facilities was used in support of commercial paper. At September 30, 2015, the Company had direct borrowings of $76 million against short-term credit facilities and $649 million against committed credit facilities.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at September 30, 2015.

On October 31, 2013 and November 1, 2013, Husky filed the U.S. Shelf Prospectus with the Alberta Securities Commission and the U.S. Securities and Exchange Commission, respectively, that enables the Company to offer up to U.S. $3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including November 30, 2015. At September 30, 2015, the Company had unused capacity of U.S. $2.25 billion under its U.S. Shelf Prospectus.

On March 17, 2014, the Company issued U.S. $750 million of 4.00 percent notes due April 15, 2024 pursuant to the U.S. Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On February 23, 2015, the Company filed the 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 units in Canada up to and including March 22, 2017. At September 30, 2015, the Company had unused capacity of $1.90 billion under its Canadian Shelf Prospectus.

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

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

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

On June 17, 2015, the Company issued six million Series 7 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $150 million, by way of a prospectus supplement dated June 10, 2015 to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $145 million. Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the board of directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

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

Capital Structure	**September 30, 2015**	
($ millions)	**Outstanding**	**Available[(1)]**
Total debt	**6,842**	**2,997**
Common shares, preferred shares, retained earnings and other reserves	**16,805**	

(1) Available long-term debt includes committed and uncommitted credit facilities.

6.3 Contractual Obligations and Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to Husky's 2014 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2014.

During the three months ended September 30, 2015, the Company had the following material changes to non-cancellable commitments:

- During the fourth quarter of 2012, the Company executed an operating lease agreement with Seadrill Limited ("Seadrill") for the semi-submersible rig, West Mira. In September 2015, Seadrill exercised its right to cancel the construction contract with its supplier due to the supplier's inability to deliver West Mira within the timeframe required. Husky subsequently cancelled its contract with Seadrill for the West Mira resulting in a reduction of approximately $780 million of minimum contractual obligations. The Company will continue to evaluate drilling rigs that are suitable for the Newfoundland offshore environment.
- During the third quarter of 2015, the Company renewed its non-cancellable agreements for $4.3 billion to supply gasoline and diesel to the Company's retail locations.

6.4 Off-Balance Sheet Arrangements

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

6.5 Transactions with Related Parties and Major Customers

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the 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 nine months ended September 30, 2015, the amount of natural gas sales to Meridian totalled $13 million and $38 million, respectively. For the three and nine months ended September 30, 2015, the amount of steam purchased by the Company from Meridian totalled $4 million and $12 million, respectively. For the three and nine months ended September 30, 2015, the total cost recovery by the Company for facilities services was $2 million and $11 million, respectively.

At September 30, 2015, $36 million of the May 11, 2009 7.25% senior notes were held by related parties and are included in long-term debt in the Company's consolidated balance sheet. Mr. Canning Fok, co-chair and a director of the Company, indirectly subscribed for $3 million of the senior notes. Ace Dimension Limited subscribed for $33 million of the senior notes. These related party transactions were measured at fair market value at the date of the transactions and have been carried out on the same terms as applied with unrelated parties.

7. Risk Management and Financial Risks

7.1 Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2014 Annual Information Form.

The Company has processes in place to identify the principal risks of the business and put in place appropriate mitigation to manage such risks where possible. The Company's exposure to operational, political, environmental, financial, liquidity and contract and credit risk has not materially changed since December 31, 2014, as discussed in Husky's 2014 Annual MD&A.

7.2 Financial Risks

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

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production and firm commitments for the purchase or sale of crude oil and natural gas. These contracts are recorded at fair value.

At September 30, 2015, the Company was party to crude oil purchase and sale derivative contracts to mitigate its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company was also party to third party physical natural gas purchase and sale derivative contracts in order to mitigate commodity price fluctuations. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities.

Interest Rate Risk Management

During 2014, the Company discontinued its cash flow hedge with respect to forward starting interest rate swaps. Accordingly, the accrued gain in other reserves is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated. The amortization period is ten years. At September 30, 2015, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $21 million (December 31, 2014 – $23 million), net of tax of $7 million (December 31, 2014 – net of tax of $8 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in offsets to finance expenses of less than $1 million and $2 million for the three and nine months ended September 30, 2015, respectively.

Refer to the interest rate swaps disclosure within Note 15 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At September 30, 2015, 71 percent or $4.3 billion of Husky's outstanding long-term debt was denominated in U.S. dollars. No long-term debt, including amounts due within one year, is exposed to changes in the Canadian/U.S. exchange rate, as all U.S. denominated debt has been designated as a hedge of the Company's net investment in its U.S. refining operations.

At September 30, 2015, the Company had designated all of its U.S. $3.2 billion denominated debt as a hedge of the Company's net investment in its U.S. refining operations. Of this amount, U.S. $250 million was designated in the third quarter of 2015. For the three and nine months ended September 30, 2015, the Company incurred an unrealized loss of $243 million and loss of $464 million, respectively, arising from the translation of the debt, net of tax of $38 million and $73 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 September 30, 2015, Husky's share of this obligation was U.S. $271 million including accrued interest. At September 30, 2015, the cost of a Canadian dollar in U.S. currency was $0.747.

The following table summarizes the Company's financial instruments that are carried at fair value in the consolidated balance sheets:

Financial Instruments at Fair Value *($ millions)*	**September 30, 2015**	December 31, 2014
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**6**	(5)
Crude oil[(2)]	**5**	4
Foreign currency contracts – FVTPL		
Foreign currency forwards	**1**	(1)
Other assets – FVTPL	**2**	2
Contingent consideration	**—**	(40)
Hedge of net investment[(3)(4)]	**(817)**	(353)
	(803)	(393)

(1) Natural gas contracts includes a $4 million decrease at September 30, 2015 (December 31, 2014 – $12 million decrease) to the fair value of held-for-trading inventory, recognized in the Condensed Interim Consolidated Balance Sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $76 million at September 30, 2015.

(2) Crude oil contracts includes a $2 million increase at September 30, 2015 (December 31, 2014 – $21 million decrease) to the fair value of held-for-trading inventory, recognized in the Condensed Interim Consolidated Balance Sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $194 million at September 30, 2015.

(3) Hedging instruments are presented net of tax.

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

8. Critical Accounting Estimates and Key Judgments

Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in Husky's 2014 Annual MD&A, as well as critical areas of judgments have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

9. Changes in Accounting Policies

Effective January 1, 2015, the Company adopted the following new accounting standards issued by the IASB:

IFRS 8 Operating Segments

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

IFRS 2 Share-based Payment

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

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

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

IFRS 3 Business Combinations

The amendment is applied prospectively and clarifies that all contingent consideration arrangements classified as liabilities (or assets) arising from a business combination should be subsequently measured at fair value through profit or loss whether or not they fall within the scope of IFRS 9 (or International Accounting Standard ("IAS") 39, as applicable). The adoption of this amended standard has no impact on the Company's Consolidated Financial Statements.

10. Outstanding Share Data

Authorized:

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

Issued and outstanding: October 27, 2015	
• common shares	984,328,915
• cumulative redeemable preferred shares, series 1	12,000,000
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	27,877,375
• stock options exercisable	16,776,429

11. Reader Advisories

This MD&A should be read in conjunction with the Condensed Interim Consolidated Financial Statements and related Notes.

Readers are encouraged to refer to Husky's 2014 Annual MD&A, the 2014 Consolidated Financial Statements and the 2014 Annual Information Form filed with Canadian securities regulatory authorities and the 2014 Form 40-F filed with the U.S. Securities and Exchange Commission for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A, the terms "Husky" and "the Company" denote the corporate entity Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended September 30, 2015 are compared to the results for the three months ended September 30, 2014 and the results for the nine months ended September 30, 2015 are compared to the results for the nine months ended September 30, 2014. Discussions with respect to Husky's financial position as at September 30, 2015 are compared to its financial position at December 31, 2014. Amounts presented within this MD&A are unaudited.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in this MD&A have been prepared in accordance with IAS 34, “Interim Financial Reporting” as issued by the International Accounting Standards Board.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended September 30, 2015 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Non-GAAP Measures

Disclosure of non-GAAP Measurements

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

Disclosure of Adjusted Net Earnings (loss)

The term "Adjusted Net Earnings (loss)" is a non-GAAP measure comprised of net earnings excluding extraordinary and non-recurring items such as after-tax property, plant and equipment impairment charges, goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing Husky's financial performance through providing comparability between periods. Adjusted net earnings (loss) was redefined in the third quarter of 2015. Previously, adjusted net earnings (loss) was defined as net earnings plus after-tax property, plant and equipment impairment charges and inventory write-downs.

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the three and nine months ended September 30, 2015 and 2014:

		Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)		**2015**	2014	**2015**	2014
GAAP	Net earnings (loss)	**(4,092)**	571	**(3,781)**	1,861
	Impairment of property, plant and equipment, net of tax	**3,664**	—	**3,664**	—
	Impairment of goodwill	**160**	—	**160**	—
	Exploration and evaluation asset write-downs, net of tax	**167**	1	**171**	3
	Inventory write-downs, net of tax	**—**	—	**—**	7
Non-GAAP	Adjusted net earnings (loss)	**(101)**	572	**214**	1,871

Disclosure of Cash Flow from Operations

The term "Cash Flow From Operations" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Cash flow from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment and other non-cash items.

The following table shows the reconciliation of net earnings to cash flow from operations and related per share amounts for the three and nine months ended September 30, 2015 and 2014:

		Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)		**2015**	2014	**2015**	2014
GAAP	Net earnings (loss)	**(4,092)**	571	**(3,781)**	1,861
	Items not affecting cash:				
	Accretion	**30**	34	**91**	102
	Depletion, depreciation, amortization and impairment	**6,074**	825	**7,843**	2,306
	Inventory write-down to net realizable value	**—**	—	**—**	9
	Exploration and evaluation expenses	**229**	2	**235**	5
	Deferred income taxes (recoveries)	**(1,510)**	7	**(1,690)**	91
	Foreign exchange (gain) loss	**14**	23	**35**	(22)
	Stock-based compensation	**(10)**	(51)	**(24)**	2
	Loss (gain) on sale of assets	**(16)**	(18)	**(10)**	(35)
	Other	**(45)**	(52)	**(10)**	71
Non-GAAP	Cash flow from operations	**674**	1,341	**2,689**	4,390
	Cash flow from operations – basic	**0.68**	1.36	**2.73**	4.46
	Cash flow from operations – diluted	**0.68**	1.36	**2.73**	4.45

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. Management believes this measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. The operating netback was determined as realized price less royalties, operating costs and transportation on a per unit basis.

Debt to Capital Employed

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

LIFO

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

Cautionary Note Required by National Instrument 51-101

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

The Company uses the term barrels of oil equivalent ("boe"), which is consistent with other oil and gas producers' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other producers 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, goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs*
Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Capital Employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gain or loss on sale of property, plant, and equipment and other non-cash items*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Production	*A company's working interest share of production before deduction of royalties*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Seismic	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Common shares, preferred shares, retained earnings and other reserves*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt including long-term debt due within one year and short-term debt*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

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

12. Forward-Looking Statements and Information

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

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", “is targeting”, "estimated", "intend", "plan", "projection", "could", “aim”, "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company’s general strategic plans and growth strategies; and anticipated production guidance range for the year;
- with respect to the Company's Asia Pacific Region: planned timing of acquisition of three-dimensional seismic survey data on the Company's offshore Taiwan block;
- with respect to the Company's Atlantic Region: anticipated timing of drilling of the Hibernia formation well at the North Amethyst field; and plans to evaluate drilling rigs suitable for a Newfoundland offshore environment;
- with respect to the Company's Oil Sands properties: expected timing and volume of increase in production from the Company's Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: anticipated timing of first production from, and forecast net peak daily production from, the Company’s Rush Lake, Edam East, Edam West and Vawn heavy oil thermal projects; and expected levels of sustaining capital required by the Company's heavy oil thermal developments once brought online;
- with respect to the Company's Western Canadian oil and gas resource plays: scheduled timing and duration, and expected impacts, of turnarounds at the Ram River plant and elsewhere in Western Canada;
- with respect to the Company's Infrastructure and Marketing segment: anticipated benefits of the expansion of the South Saskatchewan Gathering System; and expected timing of completion of expansion work at the Hardisty terminal; and
- with respect to the Company's Downstream operating segment: expected timing of completion of construction work at the BP-Husky Toledo Refinery to address updated regulatory standards; and scheduled timing and duration of maintenance turnarounds at the Lima and Toledo Refineries.

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

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky.

The Company’s Annual Information Form for the year ended December 31, 2014 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.