MANAGEMENT'S DISCUSSION AND ANALYSIS

July 24, 2013

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Jun. 30**	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30
($ millions, except where indicated)	**2013**	2013	2012	2012	2012	2012	2011	2011
Production *(mboe/day)*	**309.9**	321.3	319.3	285.0	281.9	319.9	318.9	309.1
Gross revenues[(1)]	**6,206**	5,807	5,945	5,451	5,748	5,984	5,888	6,079
Net earnings	**605**	535	474	526	431	591	408	521
Per share – Basic	**0.61**	0.54	0.48	0.53	0.44	0.61	0.42	0.55
Per share – Diluted	**0.59**	0.54	0.48	0.53	0.43	0.60	0.42	0.53
Cash flow from operations[(2)]	**1,449**	1,283	1,414	1,271	1,153	1,172	1,197	1,326
Per share – Basic	**1.47**	1.31	1.44	1.29	1.18	1.21	1.25	1.40
Per share – Diluted	**1.47**	1.30	1.44	1.29	1.17	1.20	1.24	1.39

(1) *Gross revenues have been recast to reflect a change in presentation for trading activities. Refer to Note 3 of the 2012 Consolidated Financial Statements.*
(2) *Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.*

Performance

- Production increased by 28.0 mboe/day to 309.9 mboe/day in the second quarter of 2013 compared to the second quarter of 2012 as a result of:
  - Increased crude oil production from heavy oil thermal projects in Western Canada;
  - Higher production in the Atlantic Region compared to the second quarter of 2012, which was impacted by the two major turnarounds of the SeaRose and Terra Nova floating, production, storage and offloading vessels ("FPSO");
  - Partially offset by decreased dry natural gas production due to natural reservoir declines and limited re-investment as capital is being directed to higher return oil and liquids-rich natural gas developments.

- Net earnings increased by $174 million or 40% in the second quarter of 2013 compared to the second quarter of 2012 due to:
  - Higher realized prices for crude oil in Western Canada as differentials to West Texas Intermediate ("WTI") narrowed and a significant increase in natural gas prices;
  - Increased crude oil production partially offset by decreased dry natural gas production;
  - Increased Downstream margins at the Company's Upgrading facility in Western Canada and in U.S. Refining and Marketing;
  - Partially offset by decreased Infrastructure and Marketing margins as Western Canadian location differentials narrowed.

- Cash flow from operations increased by $296 million or 26% in the second quarter of 2013 compared to the second quarter of 2012 due to the same factors impacting net earnings.

Key Projects

- At the Liwan Gas Project in the South China Sea, the central platform topsides were successfully transported and installed onto the jacket. The project is on track at approximately 90% complete at the end of the second quarter with first production planned for late 2013/early 2014. A gas sales agreement has been signed for the Liuhua 34-2 field.
- At the Sunrise Energy Project, work continues on the Central Processing Facility ("CPF") and field facilities. The project is on track at approximately 70% complete at the end of the second quarter with first production scheduled in 2014.
- At the 3,500 bbls/day Sandall heavy oil thermal development, construction is approximately 80% complete with all drilling completed during the second quarter. First production is scheduled in 2014.
- At the Rush Lake thermal development, production performance from the first single well pair pilot is in line with expectations and production from a second well pair is ramping up. First production from the 10,000 bbls/day commercial project is expected in 2015.
- Resource play development progressed in Western Canada with three oil wells (gross) and seven liquids-rich natural gas wells (gross) drilled and 14 oil wells (gross) and six liquids-rich natural gas wells (gross) completed.
- Government and regulatory approval was granted for a development plan amendment to include gas injection and storage at the South White Rose Extension offshore Newfoundland. The first gas injection development well was drilled and completed in the second quarter. Production from the South White Rose Extension is scheduled to commence at the end of 2014.
- Husky and its partner made a discovery of high-quality, light, sweet crude oil at the non-operated Harpoon O-85 exploration well in the Flemish Pass. A full analysis of the well results is ongoing.
- Fabrication of the new *West Mira* rig commenced in early June 2013. The rig will support a range of drilling activities in the Atlantic Region starting in 2015.

Financial

- Dividends on common shares of $295 million for the first quarter of 2013 were declared during the second quarter of 2013, of which $293 million and $2 million were paid in cash and common shares, respectively, on July 2, 2013.

2. Business Environment

Average Benchmarks		Three months ended Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Sept. 30, 2012	Jun. 30, 2012
WTI crude oil[(1)]	*(U.S. $/bbl)*	**94.22**	94.37	88.18	92.22	93.49
Brent crude oil[(2)]	*(U.S. $/bbl)*	**102.52**	112.55	110.00	109.48	109.29
Canadian light crude 0.3% sulphur	*($/bbl)*	**93.78**	88.42	84.43	84.89	84.37
Western Canadian Select[(3)]	*(U.S. $/bbl)*	**75.06**	62.41	70.07	70.49	70.63
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**67.24**	46.44	59.55	61.91	60.12
NYMEX natural gas[(4)]	*(U.S. $/mmbtu)*	**4.09**	3.34	3.40	2.81	2.21
NIT natural gas	*($/GJ)*	**3.40**	2.92	2.90	2.08	1.74
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**19.21**	32.18	18.29	21.94	23.58
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**22.49**	30.61	35.06	34.77	29.21
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**30.78**	26.87	28.00	35.18	27.85
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.977**	0.991	1.009	1.005	0.990
Canadian $ Equivalents						
WTI crude oil[(5)]	*($/bbl)*	**96.44**	95.23	87.39	91.76	94.43
Brent crude oil[(5)]	*($/bbl)*	**104.93**	113.57	109.02	108.94	110.39
WTI/Lloyd crude blend differential[(5)]	*($/bbl)*	**19.66**	32.47	18.13	21.83	23.82
NYMEX natural gas[(5)]	*($/mmbtu)*	**4.19**	3.37	3.37	2.79	2.23

(1) *Prices quoted are near-month contract prices for settlement during the next month.*
(2) *Dated Brent prices are dated less than 15 days prior to loading for delivery.*
(3) *Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils and is traded at Hardisty, Alberta. Quoted prices are based on the average price during the month.*
(4) *Prices quoted are average settlement prices for deliveries during the period.*
(5) *Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.*

The price Husky Energy Inc. ("Husky" or "the Company") receives for production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada, while the majority of the Company's production in the Atlantic and Asia Pacific regions is referenced to the price of Brent. The price of WTI averaged U.S. $94.22/bbl in the second quarter of 2013 compared to U.S. $93.49/bbl in the second quarter of 2012. The price of WTI averaged U.S. $94.30/bbl in the first six months of 2013 compared to U.S. $98.21/bbl in the first six months of 2012. The price of Brent averaged U.S. $102.52/bbl in the second quarter of 2013 compared to U.S. $109.29/bbl in the second quarter of 2012. The price of Brent averaged U.S. $107.54/bbl in the first six months of 2013 compared to U.S. $113.89/bbl in the first six months of 2012.

Canadian crude oil prices in the second quarter of 2013 and in the first six months of 2013 benefited from the weakening of the Canadian dollar against the U.S. dollar as compared to the same periods in 2012. In the second quarter of 2013, the price of WTI in U.S. dollars increased 1% compared to an increase of 2% in Canadian dollars when compared to the same period in 2012. In the first six months of 2013, the price of WTI in U.S. dollars decreased 4% compared to a decrease of 3% in Canadian dollars when compared to the same period in 2012.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. The light/heavy crude oil differential averaged U.S. $19.21/bbl or 20% of WTI in the second quarter of 2013 compared to U.S. $23.58/bbl or 25% of WTI in the second quarter of 2012. The light/heavy crude oil differential averaged U.S. $25.68/bbl or 27% of WTI in the first six months of 2013 compared to $22.81/bbl or 23% of WTI in the first six months of 2012.

During the second quarter of 2013, the NYMEX near-month contract price of natural gas averaged U.S. $4.09/mmbtu compared to U.S. $2.21/mmbtu in the second quarter of 2012, an increase of 85%. During the first six months of 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.72/mmbtu compared to U.S. $2.47/mmbtu during the first six months of 2012, an increase of 51%.

Foreign Exchange

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

In the second quarter of 2013, the Canadian dollar averaged U.S. $0.977, weakening by 1% compared to U.S. $0.990 during the second quarter of 2012. In the first six months of 2013, the Canadian dollar averaged U.S. $0.984, weakening by 1% compared to U.S. $0.994 during the first six months of 2012.

Refining Crack Spreads

The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and do not reflect the actual crude purchase costs or product configuration of a specific refinery.

During the second quarter of 2013, the Chicago 3:2:1 crack spread averaged U.S. $30.78/bbl compared to U.S. $27.85/bbl in the second quarter of 2012. In the first six months of 2013, the Chicago 3:2:1 crack spread averaged U.S. $28.89/bbl compared to U.S. $23.63/bbl in the first six months of 2012. During the second quarter of 2013, the New York Harbour 3:2:1 crack spread averaged U.S. $22.49/bbl compared to U.S. $29.21/bbl in the second quarter of 2012. In the first six months of 2013, the New York Harbour 3:2:1 crack spread averaged U.S. $26.42/bbl compared to U.S. $27.77/bbl in the first six months of 2012.

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

Sensitivity Analysis

The following table is indicative of the relative annualized effect on earnings before income taxes and net earnings from changes in certain key variables in the second quarter of 2013. The table below reflects what the effect would have been on the financial results for the second quarter of 2013 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the second quarter of 2013. 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	**2013 Second Quarter Average**	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	**94.22**	*U.S. $1.00/bbl*	**73**	**0.07**	**54**	**0.06**
NYMEX benchmark natural gas price[5]	**4.09**	*U.S. $0.20/mmbtu*	**13**	**0.01**	**10**	**0.01**
WTI/Lloyd crude blend differential[6]	**19.21**	*U.S. $1.00/bbl*	**(19)**	**(0.02)**	**(14)**	**(0.01)**
Canadian light oil margins	**0.049**	*Cdn $0.005/litre*	**15**	**0.01**	**11**	**0.01**
Asphalt margins	**24.24**	*Cdn $1.00/bbl*	**8**	**0.01**	**6**	**0.01**
New York Harbour 3:2:1 crack spread	**22.49**	*U.S. $1.00/bbl*	**53**	**0.05**	**34**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.977**	*U.S. $0.01*	**(66)**	**(0.07)**	**(49)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.1 million common shares outstanding as of June 30, 2013.*
(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 its three major growth pillars in the Asia Pacific Region, the Oil Sands and in 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 ("NGL") (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). The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore Greenland, offshore China, offshore Indonesia and offshore Taiwan.

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).

4. Key Growth Highlights

The 2013 Capital Program builds on the momentum achieved over the past two years with respect to repositioning the Heavy Oil and Western Canada foundation by accelerating near-term production growth and advancing Husky's three major growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

4.1 Upstream

Western Canada (Excluding Heavy Oil and Oil Sands)

Oil Resource Plays

In the second quarter of 2013, a total of three wells (gross) were drilled and 14 wells (gross) were completed across the oil resource project portfolio.

Oil Resource Plays - Drilling and Completion Activity[1][2]		Three months ended June 30, 2013		Six months ended June 30, 2013	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	1	2	6	5
Lower Shaunavon	S.W. Saskatchewan	2	—	4	1
Viking[3]	Alberta and S.W. Saskatchewan	—	12	28	24
N.Cardium	Wapiti, Alberta	—	—	4	4
Muskwa	Rainbow, Northern Alberta	—	—	6	2
Canol Shale	Northwest Territories	—	—	—	2
Total Gross		3	14	48	38
Total Net		3	14	47	37

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*
(2) *Drilling and completion activity includes operated and non-operated wells.*
(3) *Viking is comprised of project activity at Redwater in central Alberta, Alliance in southeast Alberta and drilling in southwest Saskatchewan.*

At Rainbow Muskwa, drilling and completion practices continue to be optimized based upon the results from previous wells.

At the Canol Shale project in the Northwest Territories, regulatory filings were advanced in the second quarter for future development of the play. All-season road operations and baseline studies are set to recommence in the third quarter of 2013.

Liquids-Rich Natural Gas Resource Plays

In the second quarter of 2013, a total of seven wells (gross) were drilled and six wells (gross) were completed in key plays across the liquids-rich natural gas resource portfolio.

Liquids-Rich Natural Gas Plays - Drilling and Completion Activity[1]		Three months ended June 30, 2013		Six months ended June 30, 2013	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	3	6	13	18
Duvernay	Kaybob, Alberta	4	—	4	—
Total Gross		7	6	17	18
Total Net		6	5	16	17

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

In the second quarter of 2013, three liquids-rich horizontal natural gas wells (gross) were drilled and six wells (gross) were completed at the Ansell Multi-Zone play. In addition, the Company completed its planning and preparation for a four-rig horizontal well drilling program which is scheduled to commence in the second half of 2013.

Drilling was completed on the first four-well pad at Kaybob in the Duvernay play in the second quarter of 2013. Completion activity on the four-well pad is planned for the third quarter of 2013 and production is expected to commence in late 2013. This will bring the total number of producing wells in the play to seven.

Conventional Oil and Gas

During the second quarter of 2013, 10 wells (gross) were drilled and 17 wells (gross) were completed in the conventional oil and gas portfolio.

Heavy Oil

Total production from heavy oil and thermal projects was approximately 121,000 bbls/day in the second quarter of 2013.

During the second quarter of 2013, annual turnarounds at the Pikes Peak South and Paradise Hill thermal projects were successfully completed. In the second quarter, average production levels were approximately 11,300 bbls/day at Pikes Peak South and 4,300 bbls/day at Paradise Hill, which includes the impact from the annual turnarounds.

Construction is approximately 80% complete at the 3,500 bbls/day Sandall thermal development project with all drilling completed during the second quarter. First production is scheduled for 2014.

Design and site work continued at the 10,000 bbls/day Rush Lake commercial project with first production expected in 2015. Production performance from the first single well pair pilot is in line with expectations and production from the second well pair is ramping up.

Eight horizontal heavy oil wells were drilled during the second quarter of 2013. Forty-six horizontal wells have been drilled to date, out of the 140 well program for 2013.

Four Cold Heavy Oil Production with Sand ("CHOPS") wells were drilled during the second quarter of 2013. Fifty-nine CHOPS wells have been drilled to date, out of the 200 well program for 2013.

Asia Pacific Region

China

Block 29/26

The Liwan Gas Project development on Block 29/26 in the South China Sea is approximately 90% complete and remains on track to achieve planned first production in late 2013/early 2014.

Drilling and completion work on the Liwan 3-1 gas field has concluded and all nine wells are ready for production. Four major construction vessels and their support vessels are in operation and construction continues on the deep water facilities to connect the wells and the pipeline to the shallow water central platform. During May 2013, the platform topsides were completed and transported approximately 2,500 kilometers from Qingdao, China to the South China Sea and successfully installed onto the jacket. The platform has been successfully occupied and pre-commissioning efforts are underway. The 261 kilometers of shallow water pipeline from the central platform to the gas plant has been completed and construction of the onshore gas plant is more than 95% complete. Planned first production from the Liwan 3-1 gas field remains on track for late 2013/early 2014.

A gas sales agreement has been executed with CNOOC Gas & Power Group for volumes from the Liuhua 34-2 field. The price mechanism is in line with the previously announced market pricing. The single development well for the field is expected to be tied into the Liwan 3-1 field deep water facilities with production expected to commence in the third quarter of 2014.

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

Offshore Taiwan

The Joint Operating Agreement for the block was negotiated and signed during the second quarter. The acquisition of a two-dimensional ("2-D") seismic survey is planned for the third quarter of 2013.

Indonesia

Progress continued on the shallow water gas developments in the Madura Strait Block during the second quarter. The development of the BD field in the Madura Strait Block is progressing through the tender process for major contracts. The engineering, procurement, installation and commissioning contract has been approved by Indonesia's regulatory body and the FPSO tender is under final review. The tender plans for the combined MDA and MBH development projects have been submitted to Indonesia's regulatory body for approval. First gas from the Madura Strait Block is anticipated for the 2015/2016 time frame.

Oil Sands

Sunrise Energy Project

Phase 1 of the Sunrise Energy Project is approximately 70% complete and remains on track for first production in 2014.

The CPF is approximately 60% complete with all critical modules delivered and equipment for plant 1A installed. Field facilities are approximately 95% complete, all pipelines are complete and the first well pad is being commissioned. All well pads are targeted to be completed by the end of 2013. To date, more than two-thirds of the project's total cost estimate has been spent.

A Design Basis Memorandum has been completed for the next phase of the Sunrise Energy Project. Project development continues toward the Front End Engineering Design phase.

Saleski

A regulatory application for a 3,000 bbls/day bitumen carbonate pilot was filed on May 3, 2013.

McMullen

During the second quarter of 2013, drilling and completion activities continued at McMullen. Three wells were drilled and eight slant development wells, which were drilled in the first quarter, were placed on production. At the air injection pilot, ongoing testing and monitoring of the horizontal production wells continued as planned. An amendment application to the Energy Resources Conservation Board and Alberta Environment and Sustainable Resource Development was submitted to allow the remaining three horizontal wells to be brought on production later in the year.

Atlantic Region

White Rose Field and Satellite Extensions

Government and regulatory approval was granted for a development plan amendment to include gas injection and storage at the South White Rose Extension. The development plan amendment will also enable the production of additional reserves from the main White Rose field. The project will be developed in two phases with the installation of gas injection equipment in 2013 and oil production equipment in 2014 with first oil production scheduled for the end of 2014. Installation of gas injection equipment has commenced at the South White Rose Extension drill centre offshore Newfoundland and a gas injection well for the field was drilled and completed during the second quarter. Gas injection is scheduled to commence in the second half of 2013.

Husky and its partners continue to evaluate options for the full field development of the West White Rose satellite extension. Work is underway on the proposed wellhead platform and the environmental assessment ("EA") for the wellhead platform option continues to proceed through the regulatory process.

The North Amethyst G-25-8 water injection well was re-entered and is scheduled to be drilled to total depth and completed in the third quarter of 2013 which will result in a total of eight wells in operation including four water injection wells and four production wells.

Atlantic Exploration

In mid-June, Husky and its partner announced the discovery of a high-quality, light, sweet crude oil resource at the non-operated Harpoon O-85 well in the Flemish Pass. A full analysis of the well results is ongoing. The new discovery is southeast of the Mizzen Significant Discovery Licence and Husky is a 35% partner in both discoveries. Drilling commenced in the third quarter on the non-operated Bay du Nord prospect which is located south of the Mizzen and west of the Harpoon discoveries. Husky holds a 35% working interest in the prospect.

The non-operated Federation exploration well in the southern Jeanne d'Arc Basin was spud on June 20, 2013. Husky holds a 35% working interest in the well.

Fabrication is underway on the third party owned semi-submersible drill rig *West Mira*. The rig will be used to support a range of exploration and development drilling activities in the Atlantic region commencing in 2015.

Infrastructure and Marketing

During the second quarter, construction was initiated on the Hardisty terminal expansion project which will add two 300,000 barrel storage tanks. The project is intended to increase connectivity to the Keystone Pipeline facility and re-configure the existing terminal facility to accommodate the expansion and inclusion of the Company as a Western Canadian Select stream participant by 2015.

4.2 Downstream

Lima, Ohio Refinery

Preliminary engineering design will commence in the third quarter of 2013 to revamp existing refinery process units and add new equipment to allow the Refinery to process up to 40,000 bbls/day of Western Canadian heavy oil by 2017 while maintaining the capability to refine existing light crude oil.

BP-Husky Toledo, Ohio Refinery

The Refinery continues to advance a multi-year program to improve feedstock flexibility, operational integrity and plant performance while reducing operating costs and environmental impacts.

The Hydrotreater Recycle Gas Compressor Project is scheduled to be completed in 2014. The installation of a new recycle gas compressor in the existing hydrotreater is intended to improve operational integrity and plant performance.

The Toledo Feedstock Optimization Project is intended to improve feedstock flexibility and refinery on-stream performance and allow the Refinery to reduce sulphur in refined products. The project is intended to allow the Refinery to process Sunrise Phase 1 production. The project is expected to be complete in 2015.

5. Results of Operations

5.1 Upstream

Total Second Quarter Upstream Earnings 2013 - $344 million, 2012 - $290 million.

Total Upstream net earnings include results from both the Exploration and Production operations and the Infrastructure and Marketing operations. Net earnings on a combined basis were higher in the second quarter of 2013 compared to the same period in 2012 due to increases in realized commodity prices and higher crude oil production. Realized prices in Western Canada reflect narrower location differentials to WTI benchmark prices, which drove higher Exploration and Production results, partially offset by a decrease in margins in Infrastructure and Marketing. The shift in earnings between the two operations reflects the Company's integration strategy and the ability to capture differentials as they move along the value chain.

Exploration and Production

Exploration and Production Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Gross revenues	**1,843**	1,382	**3,488**	3,353
Royalties	**(208)**	(140)	**(412)**	(359)
Net revenues	**1,635**	1,242	**3,076**	2,994
Purchases, operating, transportation and administration expenses	**608**	510	**1,167**	1,026
Depletion, depreciation and amortization	**568**	463	**1,130**	992
Exploration and evaluation expenses	**74**	53	**162**	128
Other expenses (income)	**3**	(41)	**73**	(23)
Income taxes	**99**	67	**140**	226
Net earnings	**283**	190	**404**	645

Second Quarter

Exploration and Production net earnings in the second quarter of 2013 increased by $93 million compared with the second quarter of 2012 primarily due to stronger realized commodity prices combined with higher production from the Atlantic Region and Western Canada heavy oil thermal projects, partially offset by lower natural gas production and increased operating costs and depletion, depreciation and amortization.

Production was 309.9 mboe/day in the second quarter of 2013 compared with 281.9 mboe/day in the second quarter of 2012 with an increased crude oil weighting as a result of higher production from the Atlantic Region, where the Company initiated two major turnarounds in the second quarter of 2012, and increased production in Western Canada at the Pikes Peak South and Paradise Hill heavy oil thermal projects. Natural gas production in mature fields decreased in the second quarter of 2013 compared to the same period in 2012 due to natural reservoir declines as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

The average realized price for crude oil, NGL and bitumen in the second quarter of 2013 was $77.98/bbl compared with $71.61/bbl during the same period in 2012, a 9% increase, due to higher WTI crude oil market prices combined with improved Western Canada crude oil differentials, partially offset by lower Brent crude oil market prices. Realized natural gas prices averaged $3.72/mcf in the second quarter of 2013 compared with $2.05/mcf in the same period in 2012, an increase of 81%, as natural gas supply and demand fundamentals improved from the same period in 2012.

Six Months

Exploration and Production net earnings in the first six months of 2013 were $241 million lower compared with the same period in 2012 primarily due to lower realized crude oil prices, lower natural gas production, increased operating costs in Western Canada and higher depletion, depreciation and amortization, partially offset by increased crude oil production and higher realized natural gas prices. During the first six months of 2013, average realized prices decreased by 9% to $73.11/bbl for crude oil, NGL and bitumen compared with $79.98/bbl during the same period in 2012 as Western Canadian differentials in the first quarter of 2013 widened significantly. Average realized natural gas prices were $3.39/mcf during the first six months of 2013 compared with $2.35/mcf in the same period in 2012, a 44% increase.

Average Sales Prices Realized	Three months ended June 30, 2013	2012	Six months ended June 30, 2013	2012
Crude oil and NGL *($/bbl)*				
Light crude oil & NGL	**96.22**	94.71	**99.97**	105.06
Medium crude oil	**73.62**	69.92	**67.68**	74.35
Heavy crude oil	**66.77**	60.42	**56.12**	64.62
Bitumen	**65.71**	58.09	**54.52**	61.97
Total average	**77.98**	71.61	**73.11**	79.98
Natural gas average *($/mcf)*	**3.72**	2.05	**3.39**	2.35
Total average *($/boe)*	**62.88**	51.98	**58.60**	59.04

The price realized for Western Canada crude oil in the second quarter of 2013 reflects the narrowing of Western Canada light and heavy crude oil and bitumen differentials. The significant premium to WTI realized for offshore production reflects Brent prices.

Daily Gross Production	Three months ended June 30, 2013	2012	Six months ended June 30, 2013	2012
Crude oil and NGL *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**28.6**	29.4	**29.6**	29.9
Medium crude oil	**22.9**	24.1	**23.0**	24.5
Heavy crude oil	**72.3**	78.1	**73.4**	77.2
Bitumen[1]	**48.3**	29.6	**48.0**	29.6
	172.1	161.2	**174.0**	161.2
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**40.4**	14.5	**41.8**	29.9
Terra Nova – light crude oil	**5.7**	4.5	**5.3**	5.7
	46.1	19.0	**47.1**	35.6
China				
Wenchang – light crude oil & NGL	**7.6**	8.4	**7.7**	8.5
	225.8	188.6	**228.8**	205.3
Natural gas *(mmcf/day)*	**504.7**	559.5	**521.0**	574.0
Total *(mboe/day)*	**309.9**	281.9	**315.6**	301.0

[1] *Bitumen production includes heavy oil thermal average daily gross production of 37.4 boe/day and 37.6 boe/day for the three and six months ended June 30, 2013, respectively. Heavy oil thermal production typically receives a higher price than bitumen production.*

Crude Oil and NGL Production

Second Quarter

Crude oil and NGL production in the second quarter of 2013 increased by 37.2 mbbls/day or 20% compared with the same period in 2012 due to increased production in Western Canada at the Pikes Peak South and Paradise Hill heavy oil thermal projects combined with higher production in the Atlantic Region, where the Company initiated the SeaRose and Terra Nova FPSO turnarounds in the second quarter of 2012, partially offset by lower production at maturing White Rose fields due to natural reservoir declines.

Six Months

In the first six months of 2013, crude oil and NGL production increased by 11% compared with the same period in 2012 primarily due to the same factors impacting the second quarter.

Natural Gas Production

Second Quarter

Natural gas production in the second quarter of 2013 decreased by 54.8 mmcf/day or 10% compared with the second quarter of 2012 due to natural reservoir declines in mature properties as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

Six Months

In the first six months of 2013, natural gas production decreased 9% compared with the same period in 2012 primarily due to the same factors impacting the second quarter.

2013 Production Guidance

The following table shows actual daily production for the six months ended June 30, 2013 and the year ended December 31, 2012, as well as the production guidance for 2013.

		Actual Production	
	2013 Guidance	**Six months ended June 30, 2013**	Year ended December 31, 2012
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	85 – 90	**85**	72
Medium crude oil	25 – 30	**23**	24
Heavy crude oil & bitumen	110 – 120	**121**	113
	220 – 240	**229**	209
Natural gas *(mmcf/day)*	540 – 580	**521**	554
Total *(mboe/day)*	310 – 330	**316**	302

Royalties

Second Quarter

In the second quarter of 2013, royalty rates as a percentage of gross revenues averaged 12% compared with 11% in the same period in 2012. Royalty rates in Western Canada averaged 11% in the second quarters of 2013 and 2012. Royalty rates for the Atlantic Region averaged 12% in the second quarter of 2013 up from 4% in the second quarter of 2012 when low rates reflected the initiation of the SeaRose and Terra Nova FPSO turnarounds. Royalty rates in the Asia Pacific Region averaged 23% in the second quarter of 2013 compared with 26% in the same period in 2012 primarily due to lower Brent crude oil prices.

Six Months

Royalty rates averaged 13% of gross revenues in the first six months of 2013 compared with 11% in the same period in 2012. Royalty rates in Western Canada averaged 12% in the first six months of 2013 compared with 10% in the same period in 2012 due to a royalty credit adjustment received during the second quarter of 2012. Royalty rates for the Atlantic Region averaged 13% in the first six months of 2013 compared with 12% in the same period in 2012. Royalty rates in the Asia Pacific Region averaged 25% in each of the first six months of 2013 and 2012.

Operating Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Western Canada	**438**	359	**861**	748
Atlantic Region	**50**	55	**93**	110
Asia Pacific	**6**	9	**13**	15
Total	**494**	423	**967**	873
Unit operating costs *($/boe)*	**16.79**	15.83	**15.80**	15.15

Second Quarter

Total Exploration and Production operating costs increased by $71 million in the second quarter of 2013 compared with the same period in 2012 primarily due to increased higher netback thermal crude oil production in Western Canada. Total operating costs averaged $16.79/boe in the second quarter of 2013 compared with $15.83/boe in the same period in 2012 primarily due to higher energy consumption and increased natural gas and electricity prices associated with Western Canada thermal crude oil production.

Operating costs in Western Canada averaged $17.76/boe in the second quarter of 2013 compared with $15.70/boe in the same period in 2012 primarily due to increased electricity, licensing costs, taxes, maintenance, servicing and labour costs combined with higher natural gas prices and energy consumption associated with thermal production.

Operating costs in the Atlantic Region averaged $12.16/boe in the second quarter of 2013 compared with $31.77/boe in the same period in 2012. The decrease in operating costs was attributable to higher production and lower maintenance and supply costs compared to the same period in 2012 when the SeaRose and Terra Nova FPSOs turnarounds were underway.

Operating costs in the Asia Pacific Region averaged $10.28/boe in the second quarter of 2013 compared with $11.31/boe in the same period in 2012. The decrease was due to lower helicopter, workover and health, safety, and environment costs, partially offset by lower production compared to the same period in 2012.

Six Months

Total Exploration and Production operating costs in the first half of 2013 were $967 million compared with $873 million in the same period in 2012. Operating costs in the first half of 2013 compared with the first half of 2012 averaged $16.83/boe and $15.95/boe in Western Canada, $10.89/boe and $17.02/boe in the Atlantic Region, and $9.71/boe and $9.55/boe in the Asia Pacific Region. Operating costs in the first six months of 2013 were impacted by the same factors affecting the second quarter of 2012.

Exploration and Evaluation Expenses

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Seismic, geological and geophysical	**44**	46	**77**	78
Expensed drilling	**27**	3	**79**	41
Expensed land	**3**	4	**6**	9
Exploration and evaluation expenses	**74**	53	**162**	128

Second Quarter

Exploration and evaluation expenses in the second quarter of 2013 were $74 million compared with $53 million in the second quarter of 2012 primarily due to higher expensed drilling in the current quarter as a result of adjustments to drilling rig cost allocations related to wells previously drilled.

Six Months

Exploration and evaluation expenses for the first half of 2013 were $162 million compared to $128 million in the same period of 2012 due to the same factors impacting the second quarter, as well as costs related to the winter program at the Slater River Canol Shale project where the Company completed the drilling and testing of two vertical wells and completed the baseline groundwater study in the first quarter of 2013.

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

Second Quarter

In the second quarter of 2013, total DD&A averaged $20.10/boe compared with $18.05/boe in the second quarter of 2012 as the Company continues to shift focus to investments in oil and liquids-rich natural gas properties with offsetting higher netbacks.

Six Months

For the first six months of 2013, total DD&A averaged $19.77/boe compared with $18.12/boe during the same period in 2012 due to the same factors impacting the second quarter.

Exploration and Production Capital Expenditures

In the first six months of 2013, Upstream Exploration and Production capital expenditures were $1,849 million. Capital expenditures were $964 million (52%) in Western Canada including Heavy Oil, $295 million (16%) in Oil Sands, $299 million (16%) in the Atlantic Region and $291 million (16%) in the Asia Pacific Region. Husky's major projects remain on budget and on schedule.

Exploration and Production Capital Expenditures	Three months ended June 30,		Six months ended June 30,	
($ millions)[1]	**2013**	2012	**2013**	2012
Exploration				
Western Canada	**64**	29	**174**	116
Atlantic Region	**39**	6	**44**	6
Asia Pacific Region	**—**	—	**6**	—
	103	35	**224**	122
Development				
Western Canada	**267**	293	**780**	870
Oil Sands	**137**	132	**295**	286
Atlantic Region	**116**	101	**255**	159
Asia Pacific Region	**156**	203	**285**	337
	676	729	**1,615**	1,652
Acquisitions				
Western Canada	**4**	—	**10**	5
	783	764	**1,849**	1,779

[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

Western Canada, Heavy Oil and Oil Sands

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

	Three months ended June 30,				Six months ended June 30,			
Wells Drilled	**2013**		2012		**2013**		2012	
(wells)[1]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**2**	**—**	7	3	**17**	**9**	30	21
Gas	**6**	**4**	—	—	**11**	**9**	11	10
Dry	**—**	**—**	—	—	**—**	**—**	—	—
	8	**4**	7	3	**28**	**18**	41	31
Development								
Oil	**34**	**30**	58	56	**282**	**259**	275	253
Gas	**3**	**2**	2	2	**38**	**17**	13	10
Dry	**1**	**—**	1	—	**1**	**—**	2	1
	38	**32**	61	58	**321**	**276**	290	264
Total	**46**	**36**	68	61	**349**	**294**	331	295

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

The Company drilled 294 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first six months of 2013 resulting in 268 net oil wells and 26 net natural gas wells compared with 295 net wells resulting in 274 net oil wells and 20 net natural gas wells in the same period of 2012.

During the first six months of 2013, Husky invested $964 million in exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $991 million in the same period in 2012. Property acquisitions totalling $10 million were completed in the first six months of 2013 compared with $5 million in the same period in 2012. Oil related exploration and development investment was $242 million and $245 million was invested in natural gas related exploration and development in the first six months of 2013 compared with $245 million for oil related exploration and development and $225 million for natural gas related exploration and development in the same period in 2012.

In addition, $102 million was spent on production optimization and cost reduction initiatives and $148 million was spent on facilities, land acquisition and retention and environmental protection in the first six months of 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $217 million in the first six months of 2013 compared with $245 million in the same period in 2012.

Oil Sands

During the first six months of 2013, capital expenditures on Oil Sands projects were $295 million, compared to $286 million in the same period in 2012, primarily for Phase 1 of the Sunrise Energy Project. In addition, the Company drilled 34 gross (17 net) evaluation wells for the next phase of the Sunrise Energy Project.

Atlantic Region

During the first six months of 2013, $299 million was invested in Atlantic Region projects primarily on the continued development of the White Rose Extension projects, including the North Amethyst and South White Rose Extension satellite fields. In addition, drilling is underway on one water injection well at North Amethyst and one gas injection well at the South White Rose Extension was drilled and completed in the second quarter.

Asia Pacific Region

Total capital expenditures of $291 million were invested in the Asia Pacific Region in the first six months of 2013 primarily for the development of the Liwan Gas Project.

Upstream Planned Turnarounds

A planned maintenance program on the Terra Nova FPSO is expected to be extended to 11 weeks to replace a damaged mooring chain and carry out preventative maintenance on the eight remaining mooring chains. The extended maintenance program is scheduled to commence in the third quarter of 2013.

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke production. The Company owns extensive infrastructure in Western Canada, including pipeline and storage facilities, and has access to capacity on third party pipelines and storage facilities in both Canada and the United States.

Infrastructure and Marketing Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Infrastructure gross margin	**42**	42	**74**	65
Marketing and other gross margin	**57**	120	**219**	191
Gross margin	**99**	162	**293**	256
Operating and administration expenses	**12**	20	**21**	36
Depletion, depreciation and amortization	**6**	6	**12**	11
Other income (expense)	**(1)**	1	**(1)**	—
Income taxes	**21**	35	**66**	53
Net earnings	**61**	100	**195**	156
Commodity trading volumes managed *(mboe/day)*	**167.4**	175.8	**173.9**	178.8

Second Quarter

Infrastructure and Marketing net earnings in the second quarter of 2013 decreased by $39 million compared with the same period in 2012 primarily due to decreased marketing margins in the second quarter of 2013 as a result of the narrowing of Western Canadian crude oil price differentials and fewer arbitrage opportunities available from utilizing the Company's access to infrastructure to move crude oil from Canada to the United States.

Six Months

Infrastructure and Marketing net earnings in the first six months of 2013 increased by $39 million compared with the same period in 2012 as a result of marketing activities utilizing the Company's access to infrastructure to move crude oil from Canada to the United States to mitigate the impact of wider Western Canadian crude oil differentials in the first quarter of 2013, partially offset by the impact of narrowing differentials in the second quarter.

In the first six months of 2013, Infrastructure and Marketing capital expenditures totalled $28 million and were primarily related to pipeline expenditures.

5.2 Downstream

Total Second Quarter Downstream Earnings 2013 - $295 million, 2012 - $184 million

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing. Net earnings on a combined basis reflect strong Upgrading net earnings due to an increase in the realized price of Husky Synthetic Blend and increased net earnings in U.S Refining and Marketing where realized margins were driven by higher market prices for refined products, partially offset by decreased net earnings in Canadian Refined Products where asphalt margins were impacted by turnaround activity at the Lloydminster Refinery and a reduction in government infrastructure spending.

Upgrader

Upgrader Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**573**	472	**1,102**	1,053
Gross margin[(1)]	**185**	128	**427**	257
Operating and administration expenses[(1)]	**42**	43	**81**	79
Depreciation and amortization	**23**	25	**47**	50
Other expenses	**1**	3	**2**	6
Income taxes	**31**	15	**77**	32
Net earnings	**88**	42	**220**	90
Upgrader throughput *(mbbls/day)*[(2)]	**73.8**	68.1	**74.0**	73.5
Synthetic crude oil sales *(mbbls/day)*	**56.7**	53.1	**56.4**	57.1
Upgrading differential *($/bbl)*	**27.39**	22.64	**32.96**	21.53
Unit margin *($/bbl)*[(1)]	**35.85**	26.49	**41.83**	24.73
Unit operating cost *($/bbl)*[(1)(3)]	**6.25**	6.94	**6.05**	5.91

(1) The Company reclassified certain hydrogen feedstock costs from operating and administration expenses to cost of sales in the third quarter of 2012. The 2012 periods have been reclassified to conform with current period presentation.
(2) Throughput includes diluent returned to the field.
(3) Based on throughput.

Second 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.

Upgrading net earnings in the second quarter of 2013 were $88 million compared with $42 million in the same period in 2012. The increase was primarily due to higher average upgrading differentials, throughput, and synthetic crude oil sale volumes compared to the same period in 2012 when the Company completed a turnaround for regular maintenance and a catalyst change-out.

During the second quarter of 2013, the upgrading differential averaged $27.39/bbl, an increase of $4.75/bbl or 21%, compared with the same period in 2012. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The increase in the upgrading differential was attributable to higher realized synthetic crude oil prices in the second quarter of 2013 compared to the same period in 2012 partially offset by higher Lloyd Heavy Blend costs as location differentials have narrowed. The average price for Husky Synthetic Blend in the second quarter of 2013 was $100.90/bbl compared with $90.16/bbl in the same period in 2012. The overall unit margin increased to $35.85/bbl in the second quarter of 2013 from $26.49/bbl in the same period in 2012.

Six Months

Upgrading net earnings for the first six months of 2013 increased by $130 million compared to the same period in 2012 due to higher upgrading differentials primarily driven by a deep discount on Lloyd Heavy Blend feedstock in the first quarter of 2013 and an increase in the realized price for Husky Synthetic Blend feedstock in the second quarter of 2013 when compared to the same period in 2012.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**613**	968	**1,456**	1,848
Gross margin				
Fuel	**38**	41	**74**	76
Refining	**45**	41	**93**	82
Asphalt	**49**	71	**133**	100
Ancillary	**13**	13	**26**	25
	145	166	**326**	283
Operating and administration expenses	**64**	65	**122**	119
Depreciation and amortization	**22**	21	**44**	41
Other expenses	**—**	2	**—**	3
Income taxes	**15**	20	**41**	31
Net earnings	**44**	58	**119**	89
Number of fuel outlets[(1)]	**513**	548	**513**	549
Refined products sales volume				
Light oil products *(millions of litres/day)*	**8.0**	8.4	**8.1**	8.3
Light oil products per outlet *(thousands of litres/day)*	**15.7**	12.4	**15.8**	12.1
Asphalt products *(mbbls/day)*	**22.4**	26.2	**22.3**	23.3
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**6.3**	10.4	**8.7**	10.8
Lloydminster Refinery *(mbbls/day)*	**18.7**	29.1	**23.4**	28.2
Ethanol production *(thousands of litres/day)*	**698.7**	731.8	**740.8**	727.1

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

Second Quarter

Lower fuel margins in the second quarter of 2013 compared with the same period in 2012 were primarily due to decreased sales volumes in the wholesale and bulk plant businesses resulting from an extended spring break-up and refinery turnarounds.

Higher refining gross margins in the second quarter of 2013 compared with the same period in 2012 were primarily due to higher realized pricing partially offset by lower gasoline and diesel sales volumes, higher grain feedstock prices at the Minnedosa Ethanol Plant and lower throughput at the Prince George Refinery where the Company completed a turnaround in the second quarter of 2013.

Asphalt gross margins were lower in the second quarter of 2013 compared with the same period in 2012 due to a five-week turnaround at the Lloydminster Refinery combined with an extended spring break-up and lower government infrastructure spending.

Six Months

During the first half of 2013, refined products earnings were higher than during the same period in 2012 primarily due to higher asphalt and refining margins resulting from favourable pricing and lower feedstock costs in the first quarter of 2013, partially offset by decreased throughput as a result of planned turnarounds.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Gross revenues	**2,922**	2,657	**5,633**	5,149
Gross refining margin	**418**	289	**804**	548
Operating and administration expenses	**108**	103	**213**	198
Depreciation and amortization	**58**	52	**115**	103
Other expenses	**1**	2	**2**	3
Income taxes	**88**	48	**166**	89
Net earnings	**163**	84	**308**	155
Selected operating data:				
Lima Refinery throughput *(mbbls/day)*	**149.8**	150.7	**148.3**	145.1
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**68.1**	64.9	**67.2**	66.0
Refining margin *(U.S. $/bbl crude throughput)*	**20.24**	14.79	**20.36**	14.48
Refinery inventory *(mmbbls)*[1]	**10.9**	11.0	**10.9**	11.0

[1] *Included in refinery inventory is feedstock and refined products.*

Second Quarter

U.S. Refining and Marketing net earnings increased in the second quarter of 2013 compared with the same period in 2012 primarily due to higher realized market prices for refined products and higher throughput at the BP-Husky Toledo Refinery due to minor maintenance in the second quarter of 2012 which imposed crude throughput restrictions.

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 when crude oil prices were higher. The estimated FIFO impact was an increase in net earnings of approximately $19 million in the second quarter of 2013 compared with a reduction in net earnings of approximately $60 million in the same period in 2012.

In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10% to 15% of other products which are sold at discounted market prices compared with gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Six Months

Refining margins in the first six months of 2013 were impacted primarily by the same factors affecting the second quarter. The estimated FIFO impact was an increase in net earnings of approximately $29 million in the first six months of 2013 compared with a reduction in net earnings of $40 million in the same period in 2012.

Downstream Capital Expenditures

In the first six months of 2013, Downstream capital expenditures totalled $155 million compared with $157 million in the same period in 2012. In Canada, capital expenditures of $86 million were related to upgrades at the Upgrader and the Prince George Refinery. At the Lima Refinery, $43 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $26 million (Husky's 50% share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lima Refinery is scheduled to complete a turnaround in 2014 on 70% of its operating units. The Refinery is expected to be shut down for 45 days. The remaining 30% of the operating units are scheduled to be addressed in a turnaround planned for 2015.

The Upgrader has a turnaround scheduled in the fall of 2013 and is expected to be shut down for 45 days.

5.3 Corporate

Corporate Summary	Three months ended June 30,		Six months ended June 30,	
($ millions) income (expense)	**2013**	2012	**2013**	2012
Administration expenses	**(27)**	(33)	**(70)**	(73)
Stock-based compensation	**7**	(8)	**(2)**	(12)
Depreciation and amortization	**(11)**	(9)	**(21)**	(16)
Other income (expenses)	**(5)**	(7)	**9**	(12)
Foreign exchange gains (losses)	**10**	—	**2**	(1)
Interest expense	**(1)**	(20)	**(10)**	(40)
Income taxes	**(7)**	34	**(14)**	41
Net loss	**(34)**	(43)	**(106)**	(113)

Second Quarter

The Corporate segment reported a loss of $34 million in the second quarter of 2013 compared with a loss of $43 million in the same period in 2012. Interest expense decreased by $19 million compared with the same period in 2012 due to an increase in the amount of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project. Stock-based compensation decreased by $15 million compared to the same period in 2012 due to a decrease in the Company's share price from the first quarter of 2013.

Six Months

In the first six months of 2013, the Corporate segment reported a loss of $106 million compared with a loss of $113 million in the same period of 2012. Interest expense and stock-based compensation expense were lower in the first six months of 2013 compared with the same period in 2012 due to the same factors affecting the second quarter. Other income increased by $21 million in the first six months of 2013 compared with the same period in 2012 primarily due to an insurance provision made in the second quarter of 2012 which was recovered in 2013.

Foreign Exchange Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2013**	2012	**2013**	2012
Losses on translation of U.S. dollar denominated long-term debt	**(13)**	(34)	**(21)**	(2)
Gains on cross currency swaps	**—**	8	**—**	2
Gains on contribution receivable	**16**	23	**30**	5
Other foreign exchange gains (losses)	**7**	3	**(7)**	(6)
Net foreign exchange gains (losses)	**10**	—	**2**	(1)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.985**	U.S. $1.001	**U.S. $1.005**	U.S. $0.983
At end of period	**U.S. $0.951**	U.S. $1.019	**U.S. $0.951**	U.S. $1.019

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

Consolidated Income Taxes

Consolidated income taxes increased in the second quarter of 2013 to $261 million from $151 million in the same period in 2012 resulting in an effective tax rate of 30% in the second quarter of 2013 and 26% in the same period in 2012. The effective tax rate was higher in the second quarter of 2013 compared with the same period in 2012 due to increased U.S. taxed income.

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Income taxes as reported	**261**	151	**504**	390
Cash taxes paid	**232**	206	**373**	405

Corporate Capital Expenditures

In the first six months of 2013, Corporate capital expenditures were $52 million compared with $19 million in the same period of 2012 primarily related to computer hardware and software.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the second quarter of 2013, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At June 30, 2013, Husky had total debt of $4,088 million, partially offset by cash on hand of $1,770 million, for $2,318 million of net debt compared to $1,893 million of net debt at December 31, 2012. At June 30, 2013, the Company had $3.5 billion of unused credit facilities of which $3.2 billion is long-term committed credit facilities and $290 million is short-term uncommitted credit facilities. In addition, the Company had $3.0 billion in unused capacity under its December 2012 Canadian universal short form base shelf prospectus and U.S. $1.5 billion in unused capacity under its June 2011 U.S. universal short form base shelf prospectus. The U.S. universal short form prospectus expired on July 12, 2013. The ability of the Company to utilize the capacity under its base shelf prospectus is subject to market conditions. Refer to Section 6.2.

Cash Flow Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except ratios)	**2013**	2012	**2013**	2012
Cash flow				
Operating activities	**1,225**	1,056	**2,540**	2,539
Financing activities	**(230)**	(485)	**(435)**	(8)
Investing activities	**(1,124)**	(1,164)	**(2,358)**	(2,290)
Financial Ratios[1]				
Debt to capital employed *(percent)*[2]			**17.0**	17.7
Debt to cash flow *(times)*[3][4]			**0.8**	0.8
Corporate reinvestment ratio *(percent)*[3][5]			**101**	102
Interest coverage ratios on long-term debt only[3][6]				
Earnings			**13.7**	12.2
Cash flow			**25.7**	23.7
Interest coverage ratios on total debt[3][7]				
Earnings			**13.7**	12.0
Cash flow			**25.8**	23.2

(1) Financial ratios constitute non-GAAP measures. Refer to Section 11.
(2) Debt to capital employed is equal to long-term debt and long-term debt due within one year divided by capital employed.
(3) Calculated for the 12 months ended for the dates shown.
(4) Debt to cash flow (times) is equal to long-term debt and long-term debt due within one year divided by cash flow from operations.
(5) Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations.
(6) Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow – operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.
(7) Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow – operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized interest. Total debt includes short and long-term debt.

Cash Flow from Operating Activities

Second Quarter

In the second quarter of 2013, cash flow generated from operating activities was $1.2 billion compared with $1.1 billion in the second quarter of 2012 primarily due to higher realized commodity prices and production in Exploration and Production and increased realized margins in Upgrading and U.S. Refining and Marketing.

Six Months

Cash flow generated from operating activities was $2.5 billion in each of the first six months of 2013 and 2012.

Cash Flow used for Financing Activities

Second Quarter

In the second quarter of 2013, cash flow used for financing activities was $230 million compared to cash flow used for financing activities of $485 million in the same period in 2012. The decrease was primarily due to the repayment of $400 million in long-term debt in the second quarter of 2012. This repayment of debt was funded in the first quarter of 2012 with the issuance of U.S. $500 million in senior unsecured notes.

Six Months

Cash flow used for financing activities was $435 million for the first six months of 2013 compared to cash flow used for financing activities of $8 million in the first six months of 2012. The increase in cash flow used for financing activities was primarily due to an increase in cash versus stock dividends paid in the first six months of 2013 compared to the same period in 2012.

Cash Flow used for Investing Activities

Second Quarter

Cash flow used for investing activities was $1.1 billion in the second quarter of 2013 compared to $1.2 billion in the same period in 2012. Cash invested in both periods was primarily for capital expenditures.

Six Months

Cash flow used for investing activities was $2.4 billion in the first six months of 2013 compared to $2.3 billion in the same period in 2012. Cash invested in both periods was primarily for capital expenditures.

6.2 Sources of Capital

Husky is currently able to fund its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of long-term debt and borrowings under committed and uncommitted credit facilities. The Company also maintains access to sufficient capital via debt 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.

Working capital is the amount by which current assets exceed current liabilities. At June 30, 2013, working capital was $1,647 million compared with $2,401 million at December 31, 2012.

At June 30, 2013, Husky had unused short and long-term credit facilities totalling $3.5 billion. A total of $226 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

Husky Energy (HK) Limited and Husky Oil China Ltd., subsidiaries of Husky, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes.

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.

In December 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $3.1 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. In February 2013, this amount was increased to $3.2 billion. One facility matures in August 2014 and the other facility was extended to December 2016.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Base Prospectus") with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada up to and including January 30, 2015. As of June 30, 2013, the Company had not issued Securities under the Canadian Base Prospectus. The ability of the Company to raise capital utilizing its Canadian Base Prospectus is dependent on market conditions at the time of sale.

Capital Structure		**June 30, 2013**
($ millions)	**Outstanding**	**Available[1]**
Total debt	4,088	3,481
Common shares, preferred shares, retained earnings and other reserves	19,928	

[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 2012 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2012. There were no material changes to commitments noted during the second quarter of 2013.

6.4 Off-Balance Sheet Arrangements

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

6.5 Transactions with Related Parties and Major Customers

The Company sells natural gas to and purchases steam from the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the three and six months ended June 30, 2013, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $15 million and $30 million, respectively. For the three and six months ended June 30, 2013, the amount of steam purchased by the Company from Meridian totalled $4 million and $9 million, respectively.

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 2012 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 changed since December 31, 2012, as discussed in Husky's 2012 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 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 June 30, 2013, 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

At June 30, 2013, the Company had designated a cash flow hedge using forward starting interest rate swap arrangements whereby the Company fixed the underlying U.S. 10-year Treasury Bond rate on U.S. $500 million to June 16, 2014, which is the Company's forecasted debt issuance on the same date. The effective portion of these contracts has been recorded at fair value in other assets; there was no ineffective portion at June 30, 2013. The weighted average swap rate for these forward starting swaps is 2.24%.

Refer to Note 11 of the Condensed Interim Consolidated Financial Statements.

Foreign Currency Risk Management

At June 30, 2013, 83% or $3.4 billion of Husky's outstanding debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, 10% of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At June 30, 2013, the Company had designated U.S. $2.8 billion of its U.S. denominated debt as a hedge of the Company's net investment in its U.S. refining operations. For the three and six months ended June 30, 2013, the Company incurred unrealized losses of $87 million and $137 million, respectively, arising from the translation of the debt, net of tax of $13 million and $20 million, respectively, which was recorded in net investment hedge within other comprehensive income ("OCI").

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange in current period earnings. At June 30, 2013, Husky's share of this receivable was U.S. $403 million including accrued interest. The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At June 30, 2013, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At June 30, 2013, the cost of a Canadian dollar in U.S. currency was $0.951.

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)	As at June 30, 2013	As at December 31, 2012
Derivatives – FVTPL (held-for-trading)		
Accounts receivable	16	13
Accounts payable and accrued liabilities	(2)	(5)
Other assets, including derivatives	(3)	1
Other – FVTPL (held-for-trading)[(1)]		
Accounts payable and accrued liabilities	(51)	(27)
Other long-term liabilities	(30)	(78)
Hedging instruments [(2)]		
Derivatives designated as cash flow hedge	30	1
Hedge of net investment[(3)]	(49)	88
	(89)	(7)

(1) *Non-derivative items related to contingent consideration recognized as part of a business acquisition.*
(2) *Hedging instruments are presented net of tax.*
(3) *Represents the translation of the Company's U.S. denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.*

8. Critical Accounting Estimates and Key Judgments

Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in Husky's 2012 Annual MD&A, as well as critical areas of judgments have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

9. Change in Accounting Policies and Recent Accounting Standards

9.1 Change in Accounting Policies

The following new accounting standards and amendments to existing standards, as issued by the International Accounting Standards Board ("IASB"), have been adopted by the Company effective January 1, 2013.

New Accounting Standards

IFRS 10, "Consolidated Financial Statements" provides a single control model to be applied in the assessment of control for all entities in which the Company has an investment. The adoption of this standard had no impact on the Company's consolidated financial statements.

IFRS 11, "Joint Arrangements" classifies joint arrangements as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation and apply proportionate consolidation, while parties to a joint venture have rights to the net assets of the venture and apply equity accounting. As a result of identifying and analyzing the applicability of these new standards, the Company's Madura joint arrangement will no longer be accounted for using proportionate consolidation. It will now be accounted for on an equity basis as it meets the IFRS 11 definition of a joint venture. The Company's share of income or loss in the Madura joint arrangement is included as share of equity investment on the consolidated statements of income. The adoption of this standard resulted in the following cumulative balance sheet impact, applied prospectively from January 1, 2012.

	December 31, 2012	January 1, 2012
Accounts receivable	(4)	(4)
Exploration and evaluation assets	(37)	(14)
Property, plant and equipment, net	(45)	(42)
Investment in joint ventures	132	91
Other assets	(25)	—
Accounts payable and accrued liabilities	1	18
Other long-term liabilities	3	(24)
Deferred tax liabilities	(25)	(25)
Total Balance Sheet Impact	—	—

IFRS 12, "Disclosure of Interests in Other Entities" contains new annual disclosure requirements for interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. The adoption of this standard will not have a material impact on the Company's annual consolidated financial statement disclosures.

IFRS 13, "Fair Value Measurement" establishes a single source of guidance for fair value measurement and disclosure of financial and non-financial items under IFRS. The adoption of this standard had an immaterial impact on the Company's consolidated financial statements.

Amendments to Standards

Amendments to IFRS 7, "Financial Instruments Disclosures" require additional disclosures regarding the Company's financial assets and financial liabilities that are subject to set-off rights and related arrangements. Refer to Note 11 of the Condensed Interim Consolidated Financial Statements for the additional disclosure required.

Amendments to IAS 28, "Investments in Associates and Joint Ventures" provide additional guidance applicable to accounting for interests in joint ventures or associates using the equity method of accounting. The adoption of this amended standard had no impact on the Company's consolidated financial statements.

Amendments to IAS 19, "Employee Benefits" replaced the corridor approach with immediate recognition of actuarial re-measurements and past service costs, modified the calculation of benefit costs and eliminated the expected returns on plan assets through profit or loss. Additional disclosures regarding risk, judgments and assumptions are required.

The adoption of this amended standard resulted in the following balance sheet impact, applied retrospectively to January 1, 2010.

(millions of Canadian dollars) (unaudited)	2012	2011	2010	Total
Increase/(decrease) in net defined benefit liability	1	2	(12)	(9)
Increase/(decrease) in retained earnings	(1)	(2)	12	9
Total balance sheet impact	—	—	—	—

9.2 Recent Accounting Standards

The IASB issued amendments to IAS 36, "Impairment of Assets" which require retrospective application and will be adopted by the Company on January 1, 2014. The adoption of these amended standards is not expected to have a material 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: July 19, 2013	
• common shares	983,229,181
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	32,680,760
• stock options exercisable	16,704,276

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 2012 Annual MD&A, the 2012 Consolidated Financial Statements and the 2012 Annual Information Form filed with Canadian securities regulatory authorities and the 2012 Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency, for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended June 30, 2013 are compared with results for the three months ended June 30, 2012 and the results for the six months ended June 30, 2013 are compared with results for the six months ended June 30, 2012. Discussions with respect to Husky's financial position as at June 30, 2013 are compared with its financial position at December 31, 2012. 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 International Accounting Standard ("IAS") 34, “Interim Financial Reporting” as issued by the IASB.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices 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 June 30, 2013 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 cash flow from operations, adjusted net earnings, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt and interest coverage on total debt. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of cash flow from operations and adjusted net earnings, there are no comparable measures in accordance with IFRS. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application. Except as described below, the definitions of these measurements are found in Section 6.1.

Disclosure of Adjusted Net Earnings

The term "Adjusted Net Earnings" is a non-GAAP measure comprised of net earnings adjusted for certain items not considered indicative of the Company's on-going financial performance. Adjusted net earnings is a complementary measure used in assessing Husky's financial performance through providing comparability between periods.

The following table shows the reconciliation of net earnings to adjusted net earnings and related per share amounts for the three and six months ended June 30, 2013:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		**2013**	2012	**2013**	2012
GAAP	Net earnings	**605**	431	**1,140**	1,022
	Foreign exchange	**(3)**	—	**3**	—
	Financial instruments	**12**	8	**11**	(20)
	Stock-based compensation	**(6)**	6	**1**	9
	Inventory write-downs	**2**	—	**2**	—
Non-GAAP	Adjusted net earnings	**610**	445	**1,157**	1,011
	Adjusted net earnings – basic	**0.62**	0.46	**1.18**	1.04
	Adjusted net earnings – diluted	**0.62**	0.45	**1.18**	1.03

Disclosure of Cash Flow from Operations

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

The following table shows the reconciliation of cash flow – operating activities to cash flow from operations and related per share amounts for the three and six months ended June 30, 2013:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		**2013**	2012	**2013**	2012
GAAP	Cash flow – operating activities	**1,225**	1,056	**2,540**	2,539
	Settlement of asset retirement obligations	**20**	24	**63**	57
	Income taxes paid	**232**	206	**373**	405
	Interest received	**(5)**	(8)	**(8)**	(19)
	Change in non-cash working capital	**(23)**	(125)	**(236)**	(657)
Non-GAAP	Cash flow from operations	**1,449**	1,153	**2,732**	2,325
	Cash flow from operations – basic	**1.47**	1.18	**2.78**	2.40
	Cash flow from operations – diluted	**1.47**	1.17	**2.78**	2.38

Cautionary Note Required by National Instrument 51-101

The Company uses the term barrels of oil equivalent ("boe"), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

Terms

Adjusted Net Earnings	*Net earnings plus after-tax foreign exchange gains and losses, gains and losses from the use of financial instruments, stock-based compensation expense or recovery and any asset impairments and 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	*Short and long-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	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid, interest received and changes in non-cash working capital*
Corporate Reinvestment Ratio	*Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations*
Debt to Capital Employed	*Long-term debt and long-term debt due within one year divided by capital employed*
Debt to Cash Flow	*Long-term debt and long-term debt due within one year divided by cash flow from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Front End Engineering Design ("FEED")	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Production	*A company's working interest share of production before deduction of royalties*
Interest Coverage Ratio	*A calculation of a company's ability to meet its interest payment obligation. It is equal to net earnings or cash flow – operating activities before finance expense divided by finance expense and capitalized interest*
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	*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 current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

bbls	*barrels*	*mbbls*	*thousand barrels*
boe	*barrels of oil equivalent*	*mbbls/day*	*thousand barrels per day*
CHOPS	*cold heavy oil production with sand*	*mboe*	*thousand barrels of oil equivalent*
CNOOC	*China National Offshore Oil Corporation*	*mboe/day*	*thousand barrels of oil equivalent per day*
CPF	*Central Processing Facility*	*mcf*	*thousand cubic feet*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A)*	*MD&A*	*Management's Discussion and Analysis*
FEED	*Front end engineering design*	*mmbbls*	*million barrels*
FIFO	*first in first out*	*mmboe*	*million barrels of oil equivalent*
FPSO	*Floating production, storage and offloading vessel*	*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*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
IFRS	*International Financial Reporting Standards*	*WTI*	*West Texas Intermediate*

12. Forward-Looking Statements and Information

Certain statements in this interim report 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 interim report are forward-looking and not historical facts. Such forward-looking statements are based on the Company's current expectations, estimates, projections and assumptions that were made by the Company in light of its experience and its perception of historical trends. Further, such forward-looking statements are subject to risks, uncertainties and other factors, some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed or projected in the forward-looking statements.

Some of the forward-looking statements and information 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 interim report include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; the Company's production guidance for 2013; and anticipated timing of a forecasted debt issuance;
- with respect to the Company's Asia Pacific region: planned timing of first production at the Company's Liwan Gas Project; tie-in plans and timing of planned first production from the Company's Liuhua 34-2 field; and planned acquisition of seismic survey work for the Company's offshore Taiwan block;
- with respect to the Company's Atlantic region: anticipated timing of completion and benefits of the *West Mira* rig; planned timing of and anticipated benefits from installation of gas injection equipment and oil production equipment at the Company's South White Rose Extension project; scheduled timing of first oil production from the Company's South White Rose Extension project; scheduled timing of commencement of gas injection at the Company's South White Rose Extension project; scheduled timing of drilling and completion at the Company's North Amethyst G-25-8 water injection well; and scheduled timing and duration of a maintenance program at the Terra Nova FPSO;
- with respect to the Company's Oil Sands properties: anticipated timing of first production from the Company's Sunrise Energy Project; anticipated timing of additional production being brought on at McMullen; targeted timing of completion of well pads at the Company's Sunrise Energy Project; and anticipated volumes of production from a bitumen carbonate pilot project at the Company's Saleski field;
- with respect to the Company's Heavy Oil properties: anticipated timing and volume of production from the Company's Sandall heavy oil thermal development project; anticipated timing and volume of production from the Company's Rush Lake thermal development project; and 2013 drilling programs for horizontal wells and CHOPS wells;

- with respect to the Company's Western Canadian oil and gas resource plays: anticipated timing of recommencement of all-season road operations and baseline studies at the Company's Canol Shale project in the Northwest Territories; scheduled timing of commencement of the drilling program at the Company's Ansell play; and planned timing of completion activity and commencement of production at the Company's Duvernay play at Kaybob; and
- with respect to the Company's Infrastructure and Marketing and Downstream operating segments: expected timing of commencement of preliminary engineering redesign for refinery process units at the Lima, Ohio Refinery, including anticipated timeline and outcomes of such redesign; anticipated benefits of the multi-year improvement project at the BP-Husky Toledo, Ohio Refinery; scheduled timing of completion, and anticipated benefits of, the Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo, Ohio Refinery; anticipated timing and benefits of the Toledo Feedstock Optimization Project at the BP-Husky Toledo, Ohio Refinery; and expected timing and duration of scheduled turnarounds at the Lima Refinery and the Lloydminster Upgrader.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this interim report 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, 2012 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the 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.