MANAGEMENT'S DISCUSSION AND ANALYSIS

July 23, 2012

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Jun. 30**	Mar. 31	Dec. 31	Sep. 30	Jun. 30	Mar. 31	Dec. 31	Sep. 30
($ millions, except where indicated)	**2012**	2012	2011	2011	2011	2011	2010	2010
Production *(mboe/day)*	**281.9**	319.9	318.9	309.1	311.6	310.4	280.5	288.7
Gross revenues[(1)]	**5,748**	5,984	5,894	6,073	6,043	5,072	4,294	4,124
Net earnings	**431**	591	408	521	669	626	139	261
Per share – Basic	**0.44**	0.61	0.42	0.55	0.73	0.70	0.16	0.31
Per share – Diluted	**0.43**	0.60	0.42	0.53	0.71	0.70	0.16	0.30
Cash flow from operations[(2)]	**1,153**	1,172	1,197	1,326	1,511	1,164	685	794
Per share – Basic	**1.18**	1.21	1.25	1.40	1.68	1.31	0.80	0.93
Per share – Diluted	**1.17**	1.20	1.24	1.39	1.67	1.30	0.80	0.93

(1) *Gross revenues have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation for trading activities. Refer to Section 9 and Notes 3 and 12 of the Consolidated Condensed Interim 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 in the quarter decreased by 29.7 mboe/day to 281.9 mboe/day compared with the same period in 2011 due to:
  - Decreased crude oil production in the Atlantic Region as the planned major turnarounds of the SeaRose floating, production, storage and offloading vessel ("FPSO") commenced on May 3, 2012, and Terra Nova FPSO commenced on June 8, 2012. Production in the second quarter of 2012 was approximately 34,000 bbls/day lower than the second quarter of 2011 primarily due to the offstation turnarounds.
  - Decreased natural gas production as a result of natural reservoir declines and limited re-investment as capital is directed to higher return oil and liquids-rich gas developments.
  - Partially offset by increased crude oil production in Western Canada, Heavy Oil and Bitumen.
- Net earnings in the second quarter of 2012 decreased by 30%, excluding a $55 million after-tax gain on an asset swap in the second quarter of 2011, when compared to the second quarter of 2011 due to:

- Decreased production as a result of the Atlantic Region planned offstation turnarounds.
- Lower commodity prices and refined product margins.
- The impact of wider product and Western Canada location differentials was offset by the integration of Infrastructure and Marketing and Downstream operations.

- Cash flow from operations in the quarter decreased compared to the second quarter of 2011 mainly due to decreased crude oil production in the Atlantic Region, lower commodity prices and lower refined product margins.

Key Projects

- White Rose offstation turnaround – the SeaRose FPSO planned maintenance commenced May 3, 2012 and is progressing on schedule. The impact of this offstation turnaround on production is expected to be approximately 12,000 bbls/day averaged over 2012.
- Sunrise Energy Project – detailed engineering work on the field facilities was completed on schedule during the second quarter with related construction approximately 50% complete. The central processing facility is approximately 30% complete.
- Liwan Gas Project – the jacket for the shallow water platform is complete and was loaded out in mid-July for transport to the South China Sea and other project elements remain on track.
- Madura Strait – the development plan for the MDA and MBH fields was submitted to the government and drilling commenced at the end of June on a six-plus well exploration drilling program.
- Atlantic Region – the project description for the full field development at West White Rose was filed with the regulator to commence the review process.
- Heavy Oil Thermal – first oil was achieved ahead of schedule at both Pikes Peak South and Paradise Hill thermal projects at the end of the quarter. Both of these thermal projects are expected to reach full production of 8,000 bbls/day at Pikes Peak South and 3,000 bbls/day at Paradise Hill by the end of the year. The Sandall 3,500 bbls/day heavy oil thermal development project was sanctioned.
- Western Canada oil and liquids-rich gas resource plays – drilling progressed with 52 wells drilled in the first six months of 2012. In the Northwest Territories, the Slater River Project three dimensional ("3-D") seismic processing progressed and planning is underway for the 2012/2013 winter program.

Financial

- On June 15, 2012, the Company repaid U.S. $400 million of 6.25% notes at maturity.
- Dividends on common shares of $292 million for the first quarter of 2012 were declared during the second quarter of 2012 of which $88 million and $204 million were paid in cash and common shares, respectively.

2. Business Environment

		Three months ended				
Average Benchmarks		**Jun. 30 2012**	Mar. 31 2012	Dec. 31 2011	Sep. 30 2011	Jun. 30 2011
WTI crude oil(1)	*(U.S. $/bbl)*	**93.49**	102.93	94.06	89.76	102.56
Brent crude oil(2)	*(U.S. $/bbl)*	**109.29**	118.49	109.31	113.46	117.36
Canadian light crude 0.3% sulphur	*($/bbl)*	**84.37**	92.70	97.70	92.06	102.64
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**60.12**	69.95	76.44	62.08	71.82
NYMEX natural gas(3)	*(U.S. $/mmbtu)*	**2.21**	2.74	3.55	4.19	4.31
NIT natural gas	*($/GJ)*	**1.74**	2.39	3.27	3.53	3.55
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**23.58**	21.99	10.73	18.12	17.89
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**29.21**	26.31	22.05	33.72	25.32
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**27.85**	19.35	19.06	33.43	28.90
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.990**	0.999	0.977	1.021	1.034
Canadian $ Equivalents						
WTI crude oil(4)	*($/bbl)*	**94.43**	103.03	96.27	87.91	99.19
Brent crude oil(4)	*($/bbl)*	**110.39**	118.61	111.88	111.13	113.50
WTI/Lloyd crude blend differential(4)	*($/bbl)*	**23.82**	22.01	10.98	17.75	17.30
NYMEX natural gas(4)	*($/mmbtu)*	**2.23**	2.74	3.63	4.10	4.17

(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) *Prices quoted are average settlement prices for deliveries during the period.*
(4) *Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.*

Oil and Gas Prices

The price Husky receives for production from Western Canada is primarily driven by the price of West Texas Intermediate ("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 crude oil ("Brent"). The price of WTI averaged U.S. $93.49/bbl in the second quarter of 2012 compared with U.S. $102.56/bbl in the second quarter of 2011. The price of WTI averaged U.S. $98.21/bbl in the first six months of 2012 compared with U.S. $98.33/bbl in the first six months of 2011. The price of Brent averaged U.S. $109.29/bbl in the second quarter of 2012 compared with U.S. $117.36/bbl in the second quarter of 2011. The price of Brent averaged U.S. $113.89/bbl in the first six months of 2012 compared with U.S. $111.16/bbl in the first six months of 2011.

Lower U.S. crude oil prices have been partially offset by the weakening of the Canadian dollar against the U.S. dollar. In the second quarter of 2012, the price of WTI in U.S. dollars decreased 9% compared to a decrease of 5% in Canadian dollars when compared to the same period in 2011. In the first six months of 2012, the price of WTI in U.S. dollars decreased by less than 1% compared to an increase of 3% in Canadian dollars when compared to the same period in 2011.

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. In the second quarter of 2012, 57% of Husky's crude oil production was heavy oil or bitumen compared with 47% in the second quarter of 2011 with the increase in 2012 due to lower light crude oil production from the Atlantic Region as a result of the planned FPSO offstation turnarounds. The light/heavy crude oil differential averaged U.S. $23.58/bbl or 25% of WTI in the second quarter of 2012 compared with U.S. $17.89/bbl or 17% of WTI in the second quarter of 2011. In the first six months of 2012, 52% of Husky's crude oil production was heavy oil or bitumen compared with 46% in the first six months of 2011. The light/heavy crude oil differential averaged U.S. $22.81/bbl or 23% of WTI in the first six months of 2012 compared with $20.50/bbl or 21% of WTI in the first six months of 2011.

During the second quarter of 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.21/mmbtu compared with U.S. $4.31/mmbtu in the second quarter of 2011, a decline of 49%. During the first six months of 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.47/mmbtu compared with U.S. $4.21/mmbtu during the first six months of 2011, a decline of 41%.

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 2012, the Canadian dollar averaged U.S. $0.990, weakening by 4% compared with U.S. $1.034 during the second quarter of 2011. In the first six months of 2012, the Canadian dollar averaged U.S. $0.994, weakening by 3% compared with U.S. $1.024 during the first six months of 2011.

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 necessarily reflect the actual crude purchase costs or product configuration of a specific refinery.

During the second quarter of 2012, the Chicago 3:2:1 crack spread averaged U.S. $27.85/bbl compared with U.S. $28.90/bbl in the second quarter of 2011. In the first six months of 2012, the Chicago 3:2:1 crack spread averaged U.S. $23.63/bbl compared with U.S. $22.63/bbl in the first six months of 2011. During the second quarter of 2012, the New York Harbour 3:2:1 crack spread averaged U.S. $29.21/bbl compared with U.S. $25.32/bbl in the second quarter of 2011. In the first six months of 2012, the New York Harbour 3:2:1 crack spread averaged U.S. $27.77/bbl compared with U.S. $22.27/bbl in the first six months of 2011.

Husky's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, and transportation costs to benchmark hubs and by the time lag between the purchase and delivery of crude oil, which is 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 pre-tax cash flow and net earnings from changes in certain key variables in the second quarter of 2012. The table below reflects what the effect would have been on the financial results for the second quarter of 2012 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the second quarter of 2012.

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	**2012 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]	**93.49**	*U.S. $1.00/bbl*	**61**	**0.06**	**45**	**0.05**
NYMEX benchmark natural gas price[5]	**2.21**	*U.S. $0.20/mmbtu*	**27**	**0.03**	**20**	**0.02**
WTI/Lloyd crude blend differential[6]	**23.58**	*U.S. $1.00/bbl*	**(18)**	**(0.02)**	**(14)**	**(0.01)**
Canadian light oil margins	**0.050**	*Cdn $0.005/litre*	**15**	**0.02**	**11**	**0.01**
Asphalt margins	**15.87**	*Cdn $1.00/bbl*	**9**	**0.01**	**7**	**0.01**
New York Harbour 3:2:1 crack spread	**29.21**	*U.S. $1.00/bbl*	**54**	**0.06**	**34**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.990**	*U.S. $0.01*	**(49)**	**(0.05)**	**(36)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 973.7 million common shares outstanding as of June 30, 2012.*
(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 production in its foundation of Western Canada and Heavy Oil and reposition these areas to resource play and thermal development, while advancing its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands. The Company strategically operates and maintains Downstream assets which provide specialized support and value to its Upstream heavy oil and bitumen assets.

During the first quarter of 2012, the Company completed an evaluation of activities of the Company's former Midstream segment as a service provider to the Upstream or Downstream operations. As a result, and consistent with the Company's strategic view of its integrated business, the previously reported Midstream segment activities are aligned and reported within the Company's core exploration and production, or in upgrading and refining businesses. The Company believes this change in segment presentation allows management and third parties to more effectively assess the Company's performance. Comparative periods have been revised to conform to the new segment presentation.

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, diluents 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 and offshore Indonesia.

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

4. Key Growth Highlights

The 2012 Capital Program builds on the momentum achieved in 2011 with respect to repositioning the Western Canada and Heavy Oil foundation, accelerating near-term production growth as well as continuing to advance Husky's three major growth pillars in the Oil Sands, the Asia Pacific Region and the Atlantic Region through Upstream and Downstream initiatives.

4.1 Upstream

Western Canada (excluding Heavy Oil and Oil Sands)

Oil Resource Plays

During the second quarter of 2012, Husky continued to advance exploration and development projects on its extensive oil resource land base of approximately 800,000 net acres. Operations resumed after spring break-up with eight horizontal wells drilled during the quarter resulting in a total of 34 horizontal and 2 vertical oil wells drilled in the first half of 2012. Planned oil resource drilling activity includes up to 57 additional wells across the portfolio over the remainder of 2012.

At the Oungre Bakken project in southeast Saskatchewan, three horizontal wells were drilled in the second quarter. Seven horizontal wells have been drilled and three wells have been completed to date in 2012. Ten additional wells are planned during the remainder of 2012.

In southwest Saskatchewan at the Lower Shaunavon project, three horizontal wells that were drilled during the first quarter were completed and placed on production. There is no further activity planned for this project for the remainder of 2012.

At the southwest Saskatchewan Viking project, three of the eight horizontal wells drilled during the first quarter were completed and placed on production with up to 12 additional wells planned for the remainder of the year. At the Redwater Viking project, one horizontal well was drilled during the second quarter. A total of eight horizontal wells were drilled at the Redwater Viking project to date in 2012 with 19 more wells planned over the remainder of 2012.

Two wells were drilled in the Alliance area in south central Alberta in the second quarter. Seven additional wells are planned over the remainder of 2012.

In the northern Cardium oil resource trend, two of the three horizontal wells drilled at Wapiti in the first quarter were placed on production during the second quarter and are undergoing post fracture clean up. Two additional wells are planned in the area during 2012.

Two Rainbow Muskwa horizontal shale oil wells were successfully drilled and cased from a single pad including the first monobore well at Rainbow Muskwa in the second quarter. The first 2011 Rainbow Muskwa horizontal shale oil well was placed on production and is being monitored. A four-well summer completion program is planned for the three wells drilled in 2012 and one remaining well which was drilled in 2011. Up to seven additional wells are planned at the Rainbow Muskwa for the remainder of the year.

In the Northwest Territories, analysis of the logs and cores taken from the two vertical pilot wells drilled in the first quarter continued. The 220 square kilometer 3-D seismic program was completed in the second quarter and processing of the data is progressing. Preparations are underway for the 2012/2013 winter program.

Liquids-Rich Gas Resource Plays

At Ansell in west central Alberta, there was minimal drilling and completion activity during the quarter due to spring break-up. One Wilrich horizontal well was drilled to intermediate casing point. One vertical Cardium and one multi-zone vertical well were completed during the quarter. Twelve wells have been drilled and 31 wells have been completed to date in 2012. Up to six additional wells and 18 completions are planned at Ansell for the remainder of 2012.

At Kaybob, a total of four horizontal wells have been drilled to evaluate the Duvernay liquids-rich gas play. One well was completed, tied-in and placed on production during the second quarter. Flow rates from this well continue to be monitored. Two additional wells are scheduled for completion during the third quarter.

One horizontal well was drilled to evaluate the Montney formation on the acreage held in Sinclair, Alberta in the first quarter of 2012. Completion operations are expected during the third quarter of 2012.

Heavy Oil

During the second quarter, first oil was achieved ahead of schedule from the 8,000 bbls/day capacity Pikes Peak South and 3,000 bbls/day capacity Paradise Hill thermal projects. Production commenced on June 16, 2012 at Paradise Hill and on June 29, 2012 at Pikes Peak South. At Paradise Hill, production exited the quarter at approximately 1,200 boe/day. Both of these thermal projects are expected to reach full production by the end of the year. The 3,500 bbls/day Sandall thermal development was sanctioned, with commissioning expected in 2014.

The Rush Lake commercial project design, estimated at 8,000 bbls/day, is continuing based on production performance from the single well pair pilot. The initial planning process is ongoing for three additional commercial thermal projects which are in the early stages of reservoir evaluation and concept selection.

Horizontal developments progressed with 50 wells drilled to date out of a planned 140 to 150 well program for 2012.

Three cold heavy oil production with sand ("CHOPS") wells were drilled during the second quarter of 2012, compared to 60 CHOPS wells in the second quarter of 2011. Seventy two CHOPS wells have been drilled to date in 2012 compared to 121 wells drilled in 2011.

Four solvent Enhanced Oil Recovery ("EOR") pilots were operational during the second quarter with all the carbon dioxide ("CO_2") recovered from the Lloydminster ethanol plant being used in the ongoing solvent EOR piloting program.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. Phase 1 of the project remains on schedule for first production in 2014. Drilling of the planned 49 steam-assisted gravity drainage ("SAGD") horizontal well pairs for Phase 1 has been completed.

Detailed engineering on the field facilities was completed during the second quarter and construction of the field facilities has now reached approximately 50% with significant activity currently underway including pipelining in the field and fabrication in the module shops. The central processing facility is approximately 30% complete with piling and foundation work underway at the site and equipment manufacturing offsite. Development work continued on the next phase of the project with early engineering work proceeding.

McMullen

During the second quarter of 2012, eight slant wells that were drilled in late 2011 were put on production in the cold production development project. Drilling operations for the 32 slant well program commenced in June. At the air injection pilot, the reservoir process is proceeding as planned with production start-up anticipated in the third quarter of 2012.

Saleski

Evaluation continued on the information obtained from the vertical stratigraphic test wells drilled in 2011. Two water source and disposal test wells have been drilled to date in 2012.

Work continued on the Design Basis Memorandum ("DBM") for the Saleski pilot plant and the initial field environmental monitoring for the pilot development. These activities will support a regulatory application for the pilot development plan.

Asia Pacific Region

Offshore China Exploration, Delineation and Development

The Liwan Gas Project development on Block 29/26 in the South China Sea is making significant progress towards achieving planned first production in late 2013/early 2014.

All nine subsea production trees have been installed on wells and six associated upper completions have also been installed in the Liwan 3-1 gas field. These wells flow tested successfully at the expected production rates. The remainder of the well work is planned to be completed in the second half of 2012. Fabrication of the jacket for the shallow water central platform was completed in early July and the load-out of the jacket onto a barge was achieved on July 20, 2012. During the third quarter, the jacket will be transported from the Qingdao construction yard in Eastern China to its final offshore location in the South China

Sea. Approximately 50 kilometers of pipe has been laid to date in the deep water from the gas field to the central platform and approximately 70 kilometers of pipe has been laid to date in the shallow water from the central platform to the onshore gas plant. Fabrication of the platform topsides and construction of the onshore gas plant are also progressing on schedule. The Overall Development Plan for the development of the Liwan 3-1 gas field is progressing through the Chinese government final approval stages.

Negotiations for the sale of the gas from the Liuhua 34-2 field are ongoing. Front end engineering design ("FEED") for the development of the Liuhua 29-1 gas field is progressing.

Indonesia Exploration and Development

On the Madura Strait Block, drilling has commenced on a six-plus well exploration drilling program. On the BD field, tender prequalification has been completed for the supply of a leased FPSO with bids due for submission in the third quarter. Original Gas-In-Place ("OGIP") and FEED studies have been completed for the joint development of the MDA and MBH fields. The development plan has been submitted and is expected to be approved later this year. First gas production from the Madura Strait Block is anticipated in 2014.

Atlantic Region

White Rose Extension Projects

Development drilling continued at North Amethyst and the drilling of an infill production well commenced at the original White Rose field. The infill production well is scheduled for completion in the third quarter and is expected to facilitate increased oil recovery from this reservoir.

A supporting water injection well was completed during the second quarter of 2012 on the West White Rose pilot project. First production from the project was achieved in September 2011 utilizing existing infrastructure. The results of the two-well pilot program are being monitored to assist in the development plan for the full West White Rose field.

The project description for the full field development for the White Rose Extension Project was filed with the regulator during the second quarter to commence the review process. The Company expects to make a decision on a preferred development option later in 2012. Oil storage and processing for the field is expected to be managed by existing facilities on the SeaRose FPSO. Contracts for pre-FEED and FEED to support this project were awarded in April 2012, and concept evaluation is progressing.

Atlantic Region Exploration

Drilling of up to two exploration wells offshore Newfoundland is planned for the second half of 2012. This includes drilling in the Jeanne d'Arc Basin and further exploration near the non-operated Mizzen discovery in the Flemish Pass.

Offshore Greenland

Geotechnical evaluations continued on the Greenland concessions and socio-economic study work is expected to advance during the remainder of 2012. It is anticipated that a two-year extension on the initial exploration program for the two exploration licenses offshore Greenland will be finalized in the third quarter.

Infrastructure and Marketing

The 300,000 barrel tank constructed at the Hardisty terminal was placed in service May 2012. The tank facilitates moving volumes to U.S. Petroleum Administration for Defense Districts ("PADD") II and PADD III markets.

4.2 Downstream

Lima, Ohio Refinery

The Lima, Ohio Refinery continued to progress reliability and profitability improvement projects. The site construction of a 20 mbbls/day kerosene hydrotreater to increase jet fuel production volume is progressing on schedule and is expected to be operational in the first quarter of 2013.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is progressing as planned. Overall detailed engineering and procurement is complete and construction activities continued during the second quarter of 2012. The project recently exceeded a million person-hours without a recordable injury. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

5. Results of Operations

5.1 Upstream

Exploration and Production

Exploration and Production Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2012**	2011	**2012**	2011
Gross revenues	**1,382**	1,920	**3,353**	3,671
Royalties	**(140)**	(289)	**(359)**	(547)
Net revenues	**1,242**	1,631	**2,994**	3,124
Purchases, operating, transportation and administration expenses	**510**	447	**1,026**	930
Depletion, depreciation and amortization	**463**	483	**992**	919
Exploration and evaluation expense	**53**	88	**128**	181
Other (income)	**(41)**	(56)	**(23)**	(231)
Income taxes	**67**	182	**226**	361
Net earnings	**190**	487	**645**	964

Second Quarter

Exploration and Production net earnings in the second quarter of 2012 decreased by $297 million compared with the second quarter of 2011, which included an after-tax gain on an asset swap of $55 million. Excluding this 2011 gain, net earnings in the second quarter of 2012, related to operations, decreased due to lower oil and natural gas production, increased operating costs as a result of planned turnaround activity and lower commodity prices partially offset by lower royalties and exploration and evaluation expense.

Production decreased by 29.7 mboe/day in the second quarter of 2012 compared to the second quarter of 2011 as a result of lower crude oil production in the Atlantic Region due to the planned maintenance of the SeaRose FPSO which commenced on May 3, 2012 for the scheduled 125 day offstation turnaround and the Terra Nova FPSO offstation turnaround which commenced on June 8, 2012, and due to natural reservoir declines in natural gas properties as capital investment is being directed to higher return oil and liquids-rich gas developments. Higher heavy oil and bitumen production resulted from increased investment, and Western Canada returned to normal operating conditions compared to 2011 when forest fires and the Rainbow pipeline outage impacted production.

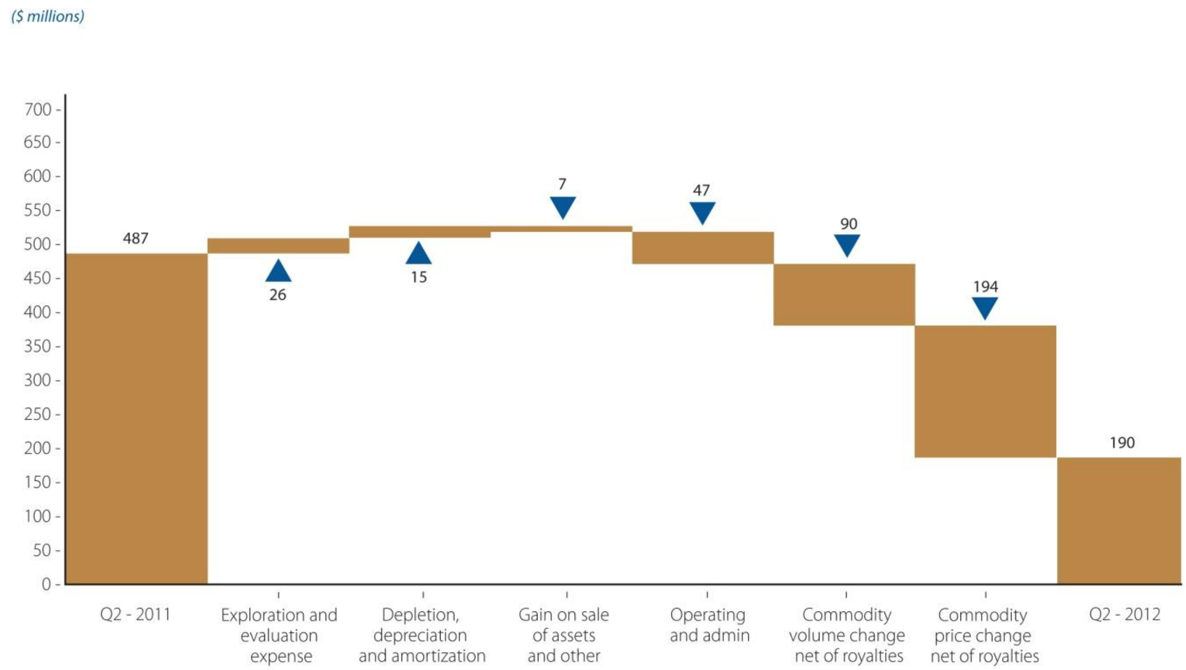
The average realized price in the second quarter of 2012 was $71.61/bbl for crude oil, NGL and bitumen compared with $87.87/bbl during the same period in 2011 due to lower commodity prices and wider differentials. Realized natural gas prices averaged $2.05/mcf in the second quarter of 2012 compared with $4.02/mcf in the same period in 2011, a decline of 49%.

Six Months

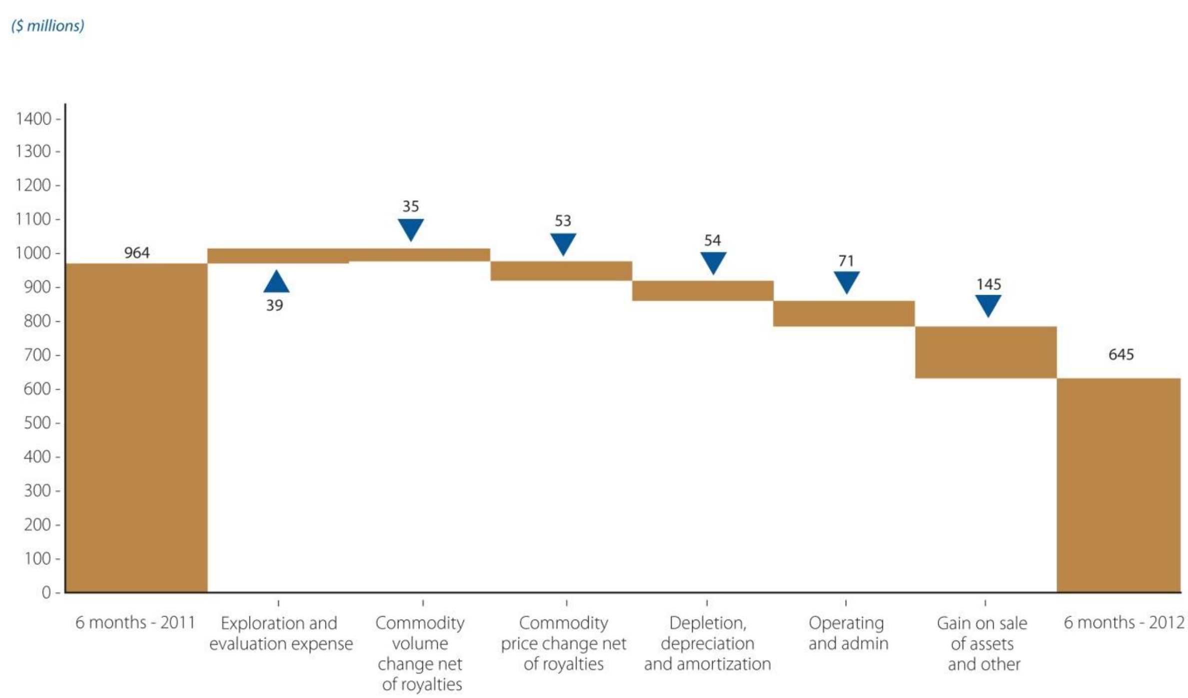
Exploration and Production net earnings in the first six months of 2012 were $319 million lower compared with the same period in 2011. In addition to the same factors impacting the second quarter, Husky realized an after-tax gain on the sale of non-core assets of $143 million in the first quarter of 2011 for a total of $198 million in the six month period. During the first six months of 2012, average realized prices decreased by 4% to $79.98/bbl for crude oil, NGL and bitumen combined compared with $83.02/bbl during the same period in 2011. Average realized natural gas prices were $2.35/mcf during the first six months of 2012 compared with $3.95/mcf in the same period in 2011.

Exploration and Production After Tax Earnings Variance Analysis

Second Quarter



Six Months



Average Sales Prices Realized	Three months ended June 30, 2012	2011	Six months ended June 30, 2012	2011
Crude oil *($/bbl)*				
Light crude oil & NGL	**94.71**	108.26	**105.06**	104.10
Medium crude oil	**69.92**	81.24	**74.35**	74.87
Heavy crude oil	**60.42**	72.51	**64.62**	66.80
Bitumen	**58.09**	69.76	**61.97**	63.90
Total average	**71.61**	87.87	**79.98**	83.02
Natural gas average *($/mcf)*	**2.05**	4.02	**2.35**	3.95
Total average *($/boe)*	**51.98**	66.33	**59.04**	63.70

The price realized for Western Canada located crude oil reflects decreases in WTI combined with wider Western Canada differentials. The significant premium realized for offshore production reflects Brent prices.

Daily Gross Production	Three months ended June 30, 2012	2011	Six months ended June 30, 2012	2011
Crude oil *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**29.4**	21.7	**29.9**	23.8
Medium crude oil	**24.1**	24.6	**24.5**	24.6
Heavy crude oil	**78.1**	73.6	**77.2**	73.5
Bitumen	**29.6**	23.6	**29.6**	23.9
	161.2	143.5	**161.2**	145.8
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**14.5**	48.8	**29.9**	49.3
Terra Nova – light crude oil	**4.5**	4.9	**5.7**	5.3
	19.0	53.7	**35.6**	54.6
China				
Wenchang – light crude oil & NGL	**8.4**	9.1	**8.5**	9.3
	188.6	206.3	**205.3**	209.7
Natural gas *(mmcf/day)*	**559.5**	631.8	**574.0**	607.7
Total *(mboe/day)*	**281.9**	311.6	**301.0**	311.0

Crude Oil and NGL Production

Second Quarter

Crude oil and NGL production in the second quarter of 2012 decreased by 17.7 mbbls/day or 9% compared with the same period in 2011. The decrease was primarily due to lower production in the Atlantic Region as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs, partially offset by higher heavy oil and bitumen production from increased investment and the return to normal operating conditions in Western Canada which was impacted by forest fires and the Rainbow pipeline outage in 2011.

Six Months

In the first six months of 2012, crude oil and NGL production decreased by 2% compared with the same period in 2011 primarily due to the same factors impacting the second quarter as well as lower production at maturing White Rose fields due to natural reservoir declines partially offset by the impact of a full six months of production from an acquisition that closed in February 2011 and new production at the West White Rose pilot program.

Natural Gas Production

Second Quarter

Natural gas production in the second quarter of 2012 decreased by 72.3 mmcf (11%) compared to the same period in 2011 due to natural reservoir declines in mature properties as capital investment is being directed to higher return oil and liquids-rich developments.

Six Months

In the first six months of 2012, natural gas production decreased 6% compared with the same period in 2011 primarily due to the same factors impacting the second quarter partially offset by the impact of a full six months of production from an acquisition that closed in February 2011.

2012 Production Guidance

The following table shows actual daily production for the six months ended June 30, 2012 and the year ended December 31, 2011, as well as the production guidance for 2012. Guidance for 2012 reflects the impacts of the planned White Rose and Terra Nova FPSO offstation turnarounds.

		Actual Production	
	2012 Guidance	**Six months ended June 30, 2012**	Year ended December 31, 2011
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	70 – 75	**74**	88
Medium crude oil	25 – 30	**24**	24
Heavy crude oil & bitumen	100 – 110	**107**	99
	195 – 215	**205**	211
Natural gas *(mmcf/day)*	560 – 610	**574**	607
Total *(mboe/day)*	290 – 315	**301**	312

Royalties

Second Quarter

In the second quarter of 2012, royalty rates as a percentage of gross revenues averaged 11% compared with 16% in the same period in 2011. Royalty rates in Western Canada averaged 11% in the second quarter of 2012 compared to 14% in the same period in 2011 due to lower natural gas prices in the quarter compared to the same period in 2011. Royalty rates for the Atlantic Region averaged 4% in the second quarter of 2012 down from 17% in the second quarter of 2011 mainly due to the settlement of a royalty audit for Terra Nova, as well as the impacts of the North Amethyst and West White Rose fields which are subject to a basic royalty of 1%. Royalty rates at North Amethyst and West White Rose will increase and reach levels similar to Terra Nova and White Rose after production levels and project payouts as prescribed in the royalty regulations are met. Royalty rates in the Asia Pacific Region averaged 26% in the second quarter of 2012 compared to 33% in the second quarter of 2011 due to decreased crude oil windfall gain taxes.

Six Months

Royalty rates averaged 11% of gross revenues in the first six months compared with 16% in the same period in 2011. Rates in Western Canada averaged 10% compared with 14% in 2011 due to a royalty credit adjustment received during the first quarter of 2012 and royalty rate decreases due to price sensitivity impacts. Royalty rates for the Atlantic Region averaged 12% compared with 17% in the same period in 2011. Royalty rates in the Asia Pacific Region averaged 25% in the first six months compared with 29% in the same period in 2011. The change in rates for the first six months was due to the same factors impacting the second quarter.

Operating Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2012**	2011	**2012**	2011
Western Canada	**359**	357	**748**	714
Atlantic Region	**55**	44	**110**	82
Asia Pacific	**9**	7	**15**	12
Total	**423**	408	**873**	808
Unit operating costs *($/boe)*	**15.83**	13.83	**15.15**	13.62

Second Quarter

Total Exploration and Production operating costs in the second quarter of 2012 increased to $423 million compared to $408 million in the second quarter of 2011. Total unit operating costs in the second quarter of 2012 averaged $15.83/boe compared to $13.83/boe for the same period in 2011 as a result of lower Atlantic Region production due to the planned FPSO offstation turnarounds.

Operating costs in Western Canada averaged $15.70/boe in the second quarter of 2012 compared with $15.63/boe in the same period in 2011. Higher maintenance, servicing and labour costs and land taxes were partially offset by lower treating and fuel costs to produce heavy oil primarily as a result of lower natural gas prices. Maturing fields in Western Canada require more extensive infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive gathering systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs associated with the increased infrastructure through cost reduction and efficiency initiatives and maximizing the utilization of the infrastructures in place.

Operating costs in the Atlantic Region averaged $31.77/boe in the second quarter of 2012 compared with $9.00/boe in the second quarter of 2011. The increase was mainly due to higher maintenance costs and lower production as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs.

Operating costs in the Asia Pacific Region averaged $11.31/boe in the second quarter of 2012 compared with $7.38/boe in the same period in 2011. This increase was due to lower production and higher maintenance, servicing and workover costs in the second quarter of 2012 compared with the same period in 2011.

Six Months

Total Exploration and Production operating costs in the first half of 2012 was $873 million compared to $808 million in the same period in 2011. Operating costs in Western Canada averaged $15.95/boe in the first half of 2012 compared to $15.72/boe in the first half of 2011 due to the same factors impacting the second quarter of 2012. Operating costs in the Atlantic Region averaged $17.02/boe in the first half of 2012 compared to $8.33/boe in the same period in 2011 due to the same factors impacting the second quarter of 2012. Operating costs in the Asia Pacific Region averaged $9.55/boe in the first half of 2012 compared to $6.66/boe in the same period in 2011 due to the same factors impacting the second quarter of 2012.

Exploration and Evaluation Expenses

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2012**	2011	**2012**	2011
Seismic, geological and geophysical	**46**	22	**78**	78
Expensed drilling	**3**	23	**41**	60
Expensed land	**4**	43	**9**	43
Exploration and evaluation expense	**53**	88	**128**	181

Second Quarter

Exploration and evaluation expenses in the second quarter of 2012 were $53 million compared with $88 million in the second quarter of 2011 primarily due to lower expensed drilling and expensed land, offset by increased seismic, geological and geophysical activity.

Increased seismic, geological and geophysical expenses related to activity in the Northwest Territories. Expensed drilling costs in the second quarter of 2011 included pilot test wells that are not subject to evaluation for economic viability as well as the Liwan 4-3-1 exploration well which was drilled and abandoned during that quarter. Expensed land costs in the second quarter of 2011 included acquisition costs expensed for properties in the Columbia River Basin located in the states of Washington and Oregon.

Six Months

Exploration and evaluation expenses for the first half of 2012 were $128 million compared to $181 million due to the same factors impacting the second quarter of 2012.

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

Second Quarter

In the second quarter of 2012, total DD&A averaged $18.05/boe compared with $17.04/boe in the second quarter of 2011. The increased DD&A rate was primarily due to production from North Amethyst and West White Rose, which have a higher capital cost base than the original White Rose field, and higher cost production replacing lower cost production in Western Canada.

Six Months

For the first six months of 2012, total DD&A averaged $18.12/boe compared with $16.34/boe during the same period in 2011 due to the same factors affecting the second quarter.

Exploration and Production Capital Expenditures

In the first six months of 2012, Upstream Exploration and Production capital expenditures were $1,779 million. Capital expenditures were $991 million (56%) in Western Canada, $286 million (16%) in the Oil Sands, $165 million (9%) in the Atlantic Region and $337 million (19%) 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)]	**2012**	2011	**2012**	2011
Exploration				
Western Canada	**29**	5	**116**	127
Atlantic Region	**6**	–	**6**	–
	35	5	**122**	127
Development				
Western Canada	**293**	254	**870**	658
Oil Sands	**132**	82	**286**	117
Atlantic Region	**101**	73	**159**	135
Asia Pacific Region	**203**	175	**337**	222
	729	584	**1,652**	1,132
Acquisitions				
Western Canada	**–**	18	**5**	860
	764	607	**1,779**	2,119

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

Western Canada, Heavy Oil & Oil Sands

The following table discloses the number of gross and net exploration and development wells Husky 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	**2012**		2011		**2012**		2011	
(wells) [(1)]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**7**	**3**	7	4	**30**	**21**	17	13
Gas	**–**	**–**	1	1	**11**	**10**	10	10
Dry	**–**	**–**	–	–	**–**	**–**	3	3
	7	**3**	8	5	**41**	**31**	30	26
Development								
Oil	**58**	**56**	107	93	**275**	**253**	309	283
Gas	**2**	**2**	5	3	**13**	**10**	36	30
Dry	**1**	**–**	2	1	**2**	**1**	2	1
	61	**58**	114	97	**290**	**264**	347	314
Total	**68**	**61**	122	102	**331**	**295**	377	340

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

The Company drilled 295 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first six months of 2012 resulting in 274 net oil wells and 20 net natural gas wells compared with the drilling of 340 net wells resulting in 296 net oil wells and 40 net natural gas wells in the same period in 2011.

Capital expenditures for wells drilled in Western Canada increased substantially in the first six months of 2012 compared with the same period in 2011 due to the increased focus on resource development drilling in areas such as the Ansell liquids-rich gas resource play, a larger number of horizontal wells drilled and more multi-stage fracture completions performed.

During the first six months of 2012, Husky invested $991 million on exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $1,645 million in the first half of 2011. Property acquisitions totaling $5 million were completed during the first six months of 2012 compared with $860 million in the first half of 2011. Oil related exploration and development investment was $245 million and $225 million was invested in natural gas related exploration and development during the first six months of 2012 compared with $218 million for oil related exploration and development and $150 million for natural gas related exploration and development in the same period in 2011.

In addition, $110 million was spent on production optimization and cost reduction initiatives in the first six months of 2012. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $161 million.

During the first six months of 2012, capital expenditures on heavy oil projects, related to thermal projects, CHOPS drilling and horizontal drilling, were $245 million compared to $232 million in the same period of 2011.

Oil Sands

During the first six months of 2012, capital expenditures on Oil Sands projects increased to $286 million compared to $117 million in the same period in 2011 as Sunrise Phase 1 progressed and activity at the central processing facility and field facilities accelerated. In addition, the Company drilled 29 gross (15 net) evaluation wells for Phase 2 at the Sunrise Energy Project during the first six months of 2012.

Atlantic Region

During the first six months of 2012, $159 million was invested in Atlantic Region projects, primarily on the continued development of the White Rose Extension Project including the West White Rose and North Amethyst satellite fields. No exploration wells were drilled in the Atlantic Region during the first six months of 2012.

Asia Pacific Region

During the first six months of 2012, total capital expenditures of $337 million were invested in the Asia Pacific Region for development related activities for the Liwan Gas Project. No exploration wells were drilled in the Asia Pacific Region during the first six months of 2012.

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)	**2012**	2011	**2012**	2011
Gross revenues	**633**	336	**1,247**	831
Marketing and other	**120**	2	**191**	37
Total revenues	**753**	338	**1,438**	868
Gross margin	**162**	53	**256**	135
Operating and administrative expenses	**20**	26	**36**	47
Depletion, depreciation and amortization	**6**	6	**11**	12
Other expenses	**1**	–	**–**	–
Income taxes	**35**	6	**53**	20
Net earnings	**100**	15	**156**	56
Commodity trading volumes managed *(mboe/day)*	**175.8**	149.8	**178.8**	194.6

Second Quarter

Infrastructure and Marketing net earnings in the second quarter of 2012 increased by $85 million compared with the second quarter of 2011 as a result of marketing activities utilizing the Company's access to infrastructure to move crude oil from Canada to the United States. Location differentials on Canadian crude oil widened during the quarter which was partially offset by lower natural gas storage margins.

Six Months

Infrastructure and Marketing net earnings in the first six months of 2012 increased by $100 million compared with the same period in 2011 and were affected by the same factors that applied in the second quarter.

In the first six months of 2012, Infrastructure and Marketing capital expenditures totalled $21 million compared to $16 million in the same period in 2011.

Upstream Planned Turnarounds

Both the SeaRose and Terra Nova FPSOs commenced planned maintenance offstation turnarounds in the second quarter. Production from the SeaRose FPSO was shut in on May 3, 2012 affecting the White Rose, North Amethyst and West White Rose fields for a planned 125 day program from production shut down to production re-start. The impact to Husky's production, averaged over the entire year, is forecasted to be approximately 12,000 bbls/day. The offstation turnaround is on schedule and on budget.

Production was shut down at the Terra Nova field on June 8, 2012 as the Terra Nova FPSO commenced a 21-week dockside maintenance program. The impact to Husky's annual production is estimated to be approximately 4,000 bbls/day. The program anticipates a return to field and reinstatement of production by the end of 2012.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues	**472**	648	**1,053**	1,016
Gross margin	**133**	174	**267**	273
Operating and administration expenses	**48**	43	**89**	101
Depreciation and amortization	**25**	88	**50**	113
Other expenses	**3**	16	**6**	28
Income taxes	**15**	7	**32**	8
Net earnings	**42**	20	**90**	23
Upgrader throughput *(mbbls/day)* (1)	**68.1**	76.1	**73.5**	64.7
Synthetic crude oil sales *(mbbls/day)*	**53.1**	61.0	**57.1**	51.0
Upgrading differential *($/bbl)*	**22.64**	33.09	**21.53**	28.62
Unit margin *($/bbl)*	**27.30**	31.35	**25.56**	29.25
Unit operating cost *($/bbl)*(2)	**7.68**	8.44	**6.53**	10.81

(1) *Throughput includes diluent returned to the field.*
(2) *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 2012 were $42 million compared with $20 million in the same period in 2011. The increase was primarily due to lower depreciation and amortization in the second quarter of 2012 compared to the second quarter of 2011 in which certain intangible costs were derecognized, partially offset by lower upgrading differentials and lower volumes due to a scheduled turnaround for regular maintenance and catalyst change-out.

During the second quarter of 2012, the upgrading differential averaged $22.64/bbl, a decrease of $10.45/bbl or 32% compared with the same period in 2011. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. In 2011, Western Canadian synthetic crude traded at a premium to WTI; however in the first and second quarter of 2012, synthetic crude traded at a discount to WTI as a result of oversupply and export pipeline constraints in Western Canada. The average price for Husky Synthetic Blend in the second quarter of 2012 was $90.16/bbl compared to $110.79/bbl in the second quarter of 2011. The overall unit margin decreased to $27.30/bbl in the second quarter of 2012 from $31.35/bbl in the same period in 2011 primarily as a result of lower product prices partially offset by lower unit operating costs resulting mainly from lower energy costs.

Six Months

Upgrading net earnings for the first six months of 2012 were affected by the same factors impacting the second quarter in addition to decreased operating expenses in the first six months of 2012 compared to the same period in 2011 due to a minor fire in early 2011.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues[1]	**968**	945	**1,848**	1,772
Gross margin				
Fuel	**41**	41	**76**	79
Refining	**41**	44	**82**	93
Asphalt	**71**	51	**100**	73
Ancillary	**13**	11	**25**	22
	166	147	**283**	267
Operating and administration expenses	**65**	61	**119**	116
Depreciation and amortization	**21**	19	**41**	37
Interest – net	**2**	2	**3**	3
Income taxes	**20**	16	**31**	28
Net earnings	**58**	49	**89**	83
Number of fuel outlets[2]	**548**	548	**549**	549
Refined products sales volume				
Light oil products *(millions of litres/day)*[3]	**8.4**	8.3	**8.3**	8.4
Light oil products per outlet *(thousands of litres/day)*[3]	**12.4**	12.1	**12.1**	12.7
Asphalt products *(mbbls/day)*	**26.2**	20.2	**23.3**	20.1
Refinery throughput				
Prince George refinery *(mbbls/day)*	**10.4**	9.1	**10.8**	10.0
Lloydminster refinery *(mbbls/day)*	**29.1**	26.2	**28.2**	27.5
Ethanol production *(thousands of litres/day)*	**731.8**	730.0	**727.1**	724.1

[1] *Gross margin and operating and administrative expenses have been recast for reclassification of certain purchases and operating expenses. Prior periods have been recast to reflect this reclassification.*
[2] *Average number of fuel outlets for period indicated.*
[3] *Light oil products have been redefined to include ethanol sales. Prior periods have been recast to reflect this change in definition.*

Second Quarter

Lower refining gross margins in the second quarter of 2012 compared to the same period in 2011 were primarily due to lower government assistance grants related to the ethanol plants.

Asphalt gross margins were significantly higher in the second quarter of 2012 compared with the second quarter of 2011 due to lower feedstock costs as crude oil prices declined.

Six Months

During the first half of 2012, refined products earnings were higher than the same period in 2011 primarily due to the same factors that affected the second quarter of 2012.

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)	**2012**	2011	**2012**	2011
Gross revenues	**2,657**	2,600	**5,149**	4,844
Gross refining margin	**289**	398	**548**	727
Operating and administration expenses	**103**	93	**198**	188
Depreciation and amortization	**52**	45	**103**	95
Interest – net	**2**	1	**3**	2
Income taxes	**48**	94	**89**	161
Net earnings	**84**	165	**155**	281
Selected operating data:				
Lima Refinery throughput *(mbbls/day)*	**150.7**	148.6	**145.1**	148.8
Toledo Refinery throughput *(mbbls/day)*	**64.9**	62.6	**66.0**	64.0
Refining margin *(U.S. $/bbl crude throughput)*	**14.79**	21.37	**14.48**	19.29
Refinery inventory *(mmbbls)*[(1)]	**11.02**	11.65	**11.02**	11.65

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

Second Quarter

U.S. Refining and Marketing net earnings decreased in the second quarter of 2012 compared with the second quarter of 2011 due to the consumption of higher priced feedstock on a FIFO basis in a declining commodity price environment combined with lower market crack spreads.

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 in the first quarter when crude oil prices were higher. The estimated FIFO impact was a reduction in net earnings of approximately $60 million in the quarter.

In addition, the product slates produced at the Lima and 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.

The unionized workforce at the Lima Refinery commenced a strike on May 25, 2012 following a breakdown in contract negotiations. Salaried employees and contractors assumed operation of the refinery maintaining optimum crude oil intake and on time and on specification delivery of products.

Six Months

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

Downstream Capital Expenditures

In the first six months of 2012, Downstream capital expenditures totalled $157 million compared with $133 million in the first six months of 2011. In Canada, capital expenditures were $49 million related to upgrades at retail stations, the Prince George Refinery and the Upgrader. In the United States, capital expenditures totalled $108 million related to U.S. refineries. At the Lima Refinery, $59 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $49 million (Husky's 50% share) primarily for construction on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Refinery has a major turnaround scheduled in the spring of 2013. The refinery is expected to be shutdown for 30 days during the turnaround for inspections and equipment repair.

The Toledo Refinery is scheduled to have a turnaround during the third quarter of 2012. The partial outage is expected to last approximately 30 days.

At the Lima Refinery, a 29-day aromatics turnaround is planned to commence in the third quarter of 2012. The planned outage is not expected to have a material impact on the crude oil rate and the unit feed will be stored and reprocessed in the fourth quarter. The Lima Refinery is scheduled to complete a major turnaround in 2014 on 70% of the operating units. The refinery is expected to be shut down for 45 days during the turnaround. The remaining 30% of the operating units are scheduled to be addressed in a major turnaround currently planned for 2015.

The Upgrader has a major turnaround scheduled in the fall of 2013. The Upgrader is expected to be shutdown for 45 days during the turnaround.

5.3 Corporate

Corporate Earnings Summary	Three months ended June 30,		Six months ended June 30,	
($ millions) income(expense)	**2012**	2011	**2012**	2011
Operating and administration expenses	**(33)**	(78)	**(73)**	(96)
Stock-based compensation	**(8)**	8	**(12)**	3
Depreciation and amortization	**(9)**	(9)	**(16)**	(16)
Other income (expenses)	**(7)**	(1)	**(12)**	1
Foreign exchange gains (losses)	**–**	17	**(1)**	19
Interest – net	**(20)**	(45)	**(40)**	(91)
Income taxes	**34**	41	**41**	68
Net loss	**(43)**	(67)	**(113)**	(112)

Second Quarter

The Corporate segment reported a loss of $43 million in the second quarter of 2012 compared with a loss of $67 million in the same period in 2011. Operating and administration expenses were significantly lower in the second quarter of 2012 compared to the same period in 2011 in which the Company incurred costs related to financing projects and other initiatives. Interest – net decreased by $25 million compared to the second quarter of 2011 due to increased amounts of capitalized interest related to projects in the Asia Pacific Region. Stock-based compensation expense increased by $16 million in the first quarter of 2012 as compared to the same period in 2011 due to new share and performance share options granted and higher share price volatility.

Six Months

In the first half of 2012, the Corporate segment reported a loss of $113 million compared with $112 million in the same period of 2011. Interest – net and operating and administration expenses were lower in the first six months of 2012 compared with the same period in 2011 due to the same factors affecting the second quarter. Other expense increased by $13 million in the first six months of 2012 compared with the same period in 2011 primarily due to an insurance provision made in the second quarter of 2012.

Foreign Exchange Summary	Three months ended June 30,		Six months ended June 30,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(34)**	15	**(2)**	63
Gains (losses) on cross currency swaps	**8**	(3)	**2**	(11)
Gains (losses) on contribution receivable	**23**	(7)	**5**	(35)
Other foreign exchange gains (losses)	**3**	12	**(6)**	2
Net foreign exchange gains (losses)	**–**	17	**(1)**	19
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $1.001**	U.S. $1.029	**U.S. $0.983**	U.S. $1.005
At end of period	**U.S. $1.019**	U.S. $1.037	**U.S. $1.019**	U.S. $1.037

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 decreased in the second quarter of 2012 to $151 million from $264 million in the second quarter of 2011 resulting in an effective tax rate of 26.1% and 28.3%, respectively.

	Three months ended June 30,		Six months ended June 30,	
($ millions)	**2012**	2011	**2012**	2011
Income taxes as reported	**151**	264	**390**	510
Cash taxes paid	**206**	32	**405**	53

Cash taxes paid in the second quarter of 2012 were $206 million compared with $32 million in the same period in 2011. Cash taxes for the remainder of 2012 are now expected to be approximately $85 million as a result of the impact of the final legislation related to the taxation of partnerships being effective for Husky in 2013, not 2012 as previously estimated.

Corporate Capital Expenditures

In the first six months of 2012, Corporate capital expenditures of $19 million were primarily related to computer hardware and software.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the second quarter of 2012, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At June 30, 2012, Husky had total debt of $4,004 million partially offset by cash on hand of $2,074 million for $1,930 million of net debt compared to $2,070 million of net debt as at December 31, 2011. At June 30, 2012, the Company had $3.3 billion in unused committed credit facilities, $311 million in unused short-term uncommitted credit facilities, $1.4 billion in unused capacity under the November 2010 universal short form base shelf prospectus filed in Canada, and U.S. $1.5 billion in unused capacity under the June 2011 U.S. base shelf prospectus. The ability of the Company to utilize the capacity under its prospectuses 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)	**2012**	2011	**2012**	2011
Cash flow				
Operating activities	**1,056**	1,451	**2,539**	2,734
Financing activities	**(485)**	571	**(8)**	648
Investing activities	**(1,164)**	(697)	**(2,290)**	(2,251)
Financial Ratios(1)				
Debt to capital employed *(percent)*(2)			**17.7**	18.0
Debt to cash flow *(times)*(3)(4)			**0.8**	0.9
Corporate reinvestment ratio *(percent)*(3)(5)			**102**	123
Interest coverage ratios on long-term debt only(3)(6)				
Earnings			**12.2**	12.4
Cash flow			**23.7**	20.9
Interest coverage on ratios of total debt(3)(7)				
Earnings			**12.0**	11.9
Cash flow			**23.2**	20.1

(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 2012, cash generated from operating activities was $1.1 billion compared with $1.5 billion in the second quarter of 2011. Lower cash flow from operating activities was primarily due to lower upstream production and lower commodity prices.

Six Months

Cash generated from operating activities amounted to $2.5 billion in the first six months of 2012 compared with $2.7 billion in the first six months of 2011. Lower cash flow from operating activities was primarily due to the same factors impacting the second quarter.

Cash Flow from Financing Activities

Second Quarter

In the second quarter of 2012, cash used in financing activities was $485 million compared to cash flow from financing activities of $571 million in the same period in 2011. The decrease in cash from financing activities was primarily due to no common share issuances in the quarter compared to a common share issuance of $1.2 billion in June 2011.

Six Months

Cash used in financing activities was $8 million for the first six months of 2012 compared to cash flow from financing activities of $648 million in 2011 due to the same factors impacting the second quarter.

Cash Flow used for Investing Activities

Second Quarter

In the second quarter of 2012, cash used for investing activities was $1.2 billion compared with $697 million in the same period in 2011. Cash invested in the current period was primarily for capital expenditures.

Six Months

Cash used for investing activities was $2.3 billion in both the first six months of 2012 and first six months of 2011. Cash invested in the current period 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, 2012, working capital was $2,735 million compared with $2,054 million at December 31, 2011.

At June 30, 2012, Husky had unused short and long-term borrowing credit facilities totalling $3.6 billion. A total of $204 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 available of $10 million for general purposes. The Company's proportionate share is $5 million.

On March 22, 2012, the Company issued U.S. $500 million of 3.95% senior unsecured notes due April 15, 2022 pursuant to a universal short form base shelf prospectus filed with the Alberta Securities Commission and the U.S. Securities and Exchange Commission on June 13, 2011 and an accompanying prospectus supplement. The notes are redeemable at the option of the Company at a make-whole premium and interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On June 15, 2012, the Company repaid the maturing 6.25% notes issued under a trust indenture dated June 14, 2002. The amount paid to note holders was U.S. $413 million, including U.S. $13 million of interest.

Capital Structure	**June 30, 2012**	
($ millions)	**Outstanding**	**Available**[(1)]
Total long-term debt	**4,004**	**3,611**
Common shares, retained earnings and other reserves	**18,610**	

[(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 2011 Annual MD&A under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments as at December 31, 2011. During the second quarter of 2012, the Company executed a new firm transportation agreement that will require future payments of approximately $12 million in 2014, $51 million in 2015/2016 and $240 million thereafter.

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 the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales are related party transactions and have been measured at fair value. For the three and six months ended June 30, 2012, the total value of natural gas sales to the Meridian and other cogeneration facilities was $8 million and $20 million, respectively. For the three and six months ended June 30, 2012, the total value of obligated steam purchases from the Meridian and other cogeneration facilities was $2 million and $6 million, respectively.

7. Risks and Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2011 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, 2011, as discussed in the Company's 2011 Annual MD&A. The following provides an update on the Company's commodity, 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 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, 2012, 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.

At June 30, 2012, the Company was party to third party crude oil purchase derivative contracts, which have been designated as a fair value hedge. The related crude oil inventory held in storage is recorded at fair value.

Foreign Currency Risk Management

At June 30, 2012, 81% or $3.2 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, 30% of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and a major portion of this receivable 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, 2012, Husky's share of this receivable was U.S. $1.0 billion 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, 2012, Husky's share of this obligation was U.S. $1.4 billion including accrued interest. At June 30, 2012, the cost of a U.S. dollar in Canadian currency was $0.9813.

8. Critical Accounting Estimates

Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in the Company's 2011 Annual MD&A, as well as critical 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 Presentation

During the first quarter of 2012, the Company completed a review of the trading activities within its Infrastructure and Marketing segment and determined that the realized and the unrealized gains and losses previously presented on a gross basis in gross revenues, purchases of crude oil and products and other – net, would be more appropriately presented on a net basis to reflect the nature of trading activities. As a result, these realized and unrealized gains and losses, and the underlying settlement of these contracts, have been recognized and recorded on a net basis in marketing and other in the condensed interim consolidated statements of income.

The net impact of this change on net earnings was nil.

10. Outstanding Share Data

Authorized:

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

Issued and outstanding: July 18, 2012

• common shares	981,998,839
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	30,994,198
• stock options exercisable	11,997,648

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 2011 Annual MD&A, the 2011 Consolidated Financial Statements and the 2011 Annual Information Form filed with Canadian regulatory agencies and the 2011 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, 2012 are compared with results for the three months ended June 30, 2011 and the results for the six months ended June 30, 2012 are compared with results for the six months ended June 30, 2011. Discussions with respect to Husky's financial position as at June 30, 2012 are compared with its financial position at December 31, 2011. Amounts presented within this MD&A are unaudited.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in this MD&A have been prepared in accordance with IAS 34.
- 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 six months ended June 30, 2012 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 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:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		**2012**	2011	**2012**	2011
GAAP	Net earnings	**431**	669	**1,022**	1,295
	Foreign exchange	**–**	(14)	**–**	(15)
	Financial instruments	**8**	7	**(20)**	15
	Stock-based compensation	**6**	(6)	**9**	(2)
	Asset impairment and write-downs	**–**	–	**–**	–
Non-GAAP	Adjusted net earnings	**445**	656	**1,011**	1,293
	Adjusted net earnings – basic	**0.46**	0.73	**1.04**	1.45
	Adjusted net earnings – diluted	**0.45**	0.72	**1.03**	1.43

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, 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:

		Three months ended June 30,		Six months ended June 30,	
($ millions)		**2012**	2011	**2012**	2011
GAAP	Cash flow – operating activities	**1,056**	1,451	**2,539**	2,734
	Settlement of asset retirement obligations	**24**	30	**57**	53
	Income taxes paid	**206**	32	**405**	53
	Interest received	**(8)**	–	**(19)**	–
	Change in non-cash working capital	**(125)**	(2)	**(657)**	(165)
Non-GAAP	Cash flow from operations	**1,153**	1,511	**2,325**	2,675
	Cash flow from operations – basic	**1.18**	1.68	**2.40**	2.99
	Cash flow from operations – diluted	**1.17**	1.67	**2.38**	2.97

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 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*
Coal Bed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
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*
Delineation Well	*A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Equity	*Shares, retained earnings and other reserves*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Feedstock	*Raw materials which are processed into petroleum products*
Front End Engineering Design	*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 Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Hectare	*One hectare is equal to 2.47 acres*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
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*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Return on Average Capital Employed	*Net earnings plus after tax interest expense divided by the two-year average capital employed*
Return on Equity	*Net earnings divided by the two-year average shareholder's equity*
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*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being competed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

bbls	*barrels*	*CDOR*	*Certificate of Deposit Offered Rate*
Bpd	*barrels per day*	*C-NLOPB*	*Canada-Newfoundland and Labrador Offshore Petroleum*
bps	*basis points*	*EOR*	*Enhanced oil recovery*
mbbls	*thousand barrels*	*EDGAR*	*Electronic Data Gathering, Analysis and Retrieval (U.S.A)*
mbbls/day	*thousand barrels per day*	*FEED*	*Front end engineering design*
mmbbls	*million barrels*	*FPSO*	*Floating production, storage and offloading vessel*
mcf	*thousand cubic feet*	*GAAP*	*Generally Accepted Accounting Principles*
mmcf	*million cubic feet*	*GDP*	*Gross domestic product*
mmcf/day	*million cubic feet per day*	*GJ*	*gigajoule*
bcf	*billion cubic feet*	*LIBOR*	*London Interbank Offered Rate*
tcf	*trillion cubic feet*	*MD&A*	*Management's Discussion and Analysis*
boe	*barrels of oil equivalent*	*MW*	*megawatt*
mboe	*thousand barrels of oil equivalent*	*NGL*	*natural gas liquids*
mboe/day	*thousand barrels of oil equivalent per day*	*NIT*	*NOVA Inventory Transfer*
mmboe	*million barrels of oil equivalent*	*NYMEX*	*New York Mercantile Exchange*
mcfge	*thousand cubic feet of gas equivalent*	*OPEC*	*Organization of Petroleum Exporting Countries*
mmbtu	*million British Thermal Units*	*PSC*	*Production sharing contract*
mmlt	*million long tons*	*PIIP*	*Petroleum initially-in-place*
tcfe	*trillion cubic feet equivalent*	*SAGD*	*Steam assisted gravity drainage*
tgal	*thousand gallons*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
ASP	*alkaline surfactant polymer*	*WI*	*working interest*
CHOPS	*cold heavy oil production with sand*	*WTI*	*West Texas Intermediate*
CNOOC	*China National Offshore Oil Corporation*	*IFRS*	*International Financial Reporting Standards*

12. Forward-Looking Statements and Information

Certain statements in this document are forward looking statements within the meaning of 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, and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements"). The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements. Any 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," "are expected to," "will continue," "is anticipated," "is targeting," "estimated," "intend," "plan," "projection," "could," "aim," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and 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 in the forward-looking statements.

In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; the Company's 2012 production guidance; the anticipated impacts of the offstation of the SeaRose FPSO and Terra Nova FPSO on the Company's annual production; and expected cash taxes for the remainder of 2012;

- with respect to the Company's Asia Pacific Region: planned timing of first production at the Company's Liwan Gas Project; planned timing of completion of well work and jacket transport at the Company's Liwan Gas Project; exploration and drilling plans at the Company's Madura Strait Block; expected timing of regulatory approval of the development plan for the Company's Madura Strait Block; and anticipated timing of first production at the Company's Madura Strait Block;

- with respect to the Company's Atlantic Region: scheduled timing and anticipated results of completion of an infill production well at the Company's White Rose field; anticipated timing of development option decisions for the Company's White Rose Extension Project; exploration and drilling plans in the region for the remainder of 2012; expected timing of socio-economic study work relating to the Company's offshore Greenland licenses; anticipated timing of a return to field and reinstatement of production for the Terra Nova FPSO; and expected timing of finalization of a two-year extension on the initial exploration program for the Company's Greenland licenses;

- with respect to the Company's Oil Sands properties: anticipated timing of first production from Phase 1 of the Company's Sunrise Energy Project; and anticipated timing of production start-up at the Company's McMullen project;

- with respect to the Company's Heavy Oil properties: planned timing of commissioning of the Company's Sandall thermal development; expected timing of full production at the Company's Pikes Peak South and Paradise Hill thermal projects; and the Company's 2012 horizontal drilling program;

- with respect to the Company's Western Canadian oil and gas resource plays: planned drilling activity in the Company's oil resource portfolio for the remainder of 2012, including drilling plans at Lower Shaunavon, Oungre Bakken, Saskatchewan Viking, Redwater Viking, Alliance, Wapiti, and drilling and completion plans at Rainbow Muskwa; drilling and completion plans for the remainder of 2012 at Ansell; and completion plans during the third quarter of 2012 at Kaybob and Sinclair; and

- with respect to the Company's Downstream operating segment: expected timing of operation of a kerosene hydrotreater at the Company's Lima Refinery; expected timing and duration of scheduled turnarounds at the Company's Lloydminster, Lima and Toledo Refineries; and expected timing and duration of a scheduled turnaround at the Company's Lloydminster Upgrader.

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

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

The Company's Annual Information Form for the year ended December 31, 2011 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.