MANAGEMENT'S DISCUSSION AND ANALYSIS

October 31, 2012

Table of Contents

1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Sept. 30**	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31
($ millions, except where indicated)	**2012**	2012	2012	2011	2011	2011	2011	2010
Production *(mboe/day)*	**285.0**	281.9	319.9	318.9	309.1	311.6	310.4	280.5
Gross revenues[(1)]	**5,451**	5,748	5,984	5,894	6,073	6,043	5,072	4,294
Net earnings	**526**	431	591	408	521	669	626	139
Per share – Basic	**0.53**	0.44	0.61	0.42	0.55	0.73	0.70	0.16
Per share – Diluted	**0.53**	0.43	0.60	0.42	0.53	0.71	0.70	0.16
Cash flow from operations[(2)]	**1,271**	1,153	1,172	1,197	1,326	1,511	1,164	685
Per share – Basic	**1.29**	1.18	1.21	1.25	1.40	1.68	1.31	0.80
Per share – Diluted	**1.29**	1.17	1.20	1.24	1.39	1.67	1.30	0.80

(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 Condensed Interim Consolidated Financial Statements.*

(2) *Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.*

Performance

- Production in the quarter was 285.0 mboe/day, a decrease of 24.1 mboe/day compared with the same period in 2011 due to:
  - Increased crude oil production in Western Canada as a result of new heavy oil thermal development projects;
  - Decreased crude oil production of approximately 35,000 bbls/day in the Atlantic Region as the planned major turnarounds of the SeaRose and Terra Nova floating, production, storage and offloading vessels ("FPSOs") commenced in the second quarter. The SeaRose FPSO restarted production in mid-August, more than three weeks ahead of schedule, and the Terra Nova turnaround continues into the fourth quarter.
  - Decreased natural gas production as a result of natural reservoir declines and limited re-investment as capital is being directed to higher return oil and liquids-rich gas developments.

- Net earnings in the third quarter of 2012 were comparable to the third quarter of 2011, with:
  - Higher throughput in both Canadian Upgrading and Refining and U.S. Refining and Marketing;
  - Stronger realized U.S. refining margins due to favourable market crack spreads; and
  - Higher Infrastructure and Marketing earnings from the utilization of infrastructure to transport crude oil from Canada to the U.S. to mitigate the impact of wider Western Canada crude oil differentials;
  - Decreased production as a result of the Atlantic Region planned FPSO offstation turnarounds; and
  - Lower realized commodity prices in Upstream.
- Cash flow from operations in the quarter decreased when compared to the third quarter of 2011 mainly due to decreased crude oil production in the Atlantic Region and lower realized commodity prices, offset by stronger U.S. refining margins and higher throughput.

Key Projects

- The SeaRose FPSO resumed production at the White Rose and satellite fields in mid-August following a planned maintenance offstation turnaround which was completed in 102 days, more than three weeks ahead of schedule. Net production ramped up to approximately 40,000 bbls/day by the end of the quarter.
- Full production levels of 8,000 bbls/day at Pikes Peak South and 3,000 bbls/day at Paradise Hill heavy oil thermal development projects were reached ahead of schedule in two months from first oil. Construction continues at the 3,500 bbls/day Sandall thermal development.
- At the Liwan Gas Project the jacket for the shallow water platform was completed and successfully placed on the seabed. All critical path project elements remain on track.
- At the Sunrise Energy Project work continues on the central processing facility, field facilities and well completion activities and the project remains on track.
- The development plan for the Madura Strait MDA and MBH fields was submitted to the government of Indonesia and approval is pending. Work continues on the exploration drilling program in the offshore Madura Strait Block. Additional new discoveries have been made which are currently being evaluated.
- Resource play development progressed with 66 horizontal wells and two vertical wells drilled in the first nine months of 2012 in Western Canada oil resource plays.

Financial

- Dividends on common shares of $294 million for the second quarter of 2012 were declared during the third quarter of 2012 of which $293 million and $1 million were paid in cash and common shares, respectively.

2. Business Environment

Average Benchmarks		Three months ended Sept. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011	Sept. 30 2011
WTI crude oil[(1)]	*(U.S. $/bbl)*	**92.22**	93.49	102.93	94.06	89.76
Brent crude oil[(2)]	*(U.S. $/bbl)*	**109.48**	109.29	118.49	109.31	113.46
Western Canada Select[(3)]	*(U.S. $/bbl)*	**70.49**	70.63	81.51	83.57	72.14
Canadian light crude 0.3% sulphur	*($/bbl)*	**84.89**	84.37	92.70	97.70	92.06
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**61.91**	60.12	69.95	76.44	62.08
NYMEX natural gas[(4)]	*(U.S. $/mmbtu)*	**2.81**	2.21	2.74	3.55	4.19
NIT natural gas	*($/GJ)*	**2.08**	1.74	2.39	3.27	3.53
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.94**	23.58	21.99	10.73	18.12
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**34.77**	29.21	26.31	22.05	33.72
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**35.18**	27.85	19.35	19.06	33.43
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.005**	0.990	0.999	0.977	1.021
Canadian $ Equivalents						
WTI crude oil[(5)]	*($/bbl)*	**91.76**	94.43	103.03	96.27	87.91
Brent crude oil[(5)]	*($/bbl)*	**108.94**	110.39	118.61	111.88	111.13
WTI/Lloyd crude blend differential[(5)]	*($/bbl)*	**21.83**	23.82	22.01	10.98	17.75
NYMEX natural gas[(5)]	*($/mmbtu)*	**2.79**	2.23	2.74	3.63	4.10

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

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. $92.22/bbl in the third quarter of 2012 compared with U.S. $89.76/bbl in the third quarter of 2011. The price of WTI averaged U.S. $96.21/bbl in the first nine months of 2012 compared with U.S. $95.48/bbl in the first nine months of 2011. The price of Brent averaged U.S. $109.48/bbl in the third quarter of 2012 compared with U.S. $113.46/bbl in the third quarter of 2011. The price of Brent averaged U.S. $113.89/bbl in the first nine months of 2012 compared with U.S. $111.93/bbl in the first nine months of 2011.

The weakening of the Canadian dollar against the U.S. dollar was partially offset by crude oil price movements. In the third quarter of 2012, the price of WTI in U.S. dollars increased by 3% compared to 4% in Canadian dollars when compared to the same period in 2011. In the first nine months of 2012, the price of WTI in U.S. dollars increased by 1% compared to 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 third quarter of 2012, 59% of Husky's crude oil production was heavy oil or bitumen compared with 48% in the third 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 and increased production from new heavy oil thermal projects. The light/heavy crude oil differential averaged U.S. $21.94/bbl or 24% of WTI in the third quarter of 2012 compared with U.S. $18.12/bbl or 20% of WTI in the third quarter of 2011. In the first nine months of 2012, 54% of Husky's crude oil production was heavy oil or bitumen compared with 47% in the first nine months of 2011. The light/heavy crude oil differential averaged U.S. $22.51/bbl or 23% of WTI in the first nine months of 2012 compared with U.S. $19.71/bbl or 21% of WTI in the first nine months of 2011.

During the third quarter of 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.81/mmbtu compared with U.S. $4.19/mmbtu in the third quarter of 2011, a decline of 33%. During the first nine months of 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.59/mmbtu compared with U.S. $4.20/mmbtu during the first nine months of 2011, a decline of 38%.

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 third quarter of 2012, the Canadian dollar averaged U.S. $1.005, weakening by 2% compared with U.S. $1.021 during the third quarter of 2011. In the first nine months of 2012, the Canadian dollar averaged U.S. $0.998, weakening by 2% compared with U.S. $1.023 during the first nine 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 third quarter of 2012, the Chicago 3:2:1 crack spread averaged U.S. $35.18/bbl compared with U.S. $33.43/bbl in the third quarter of 2011. In the first nine months of 2012, the Chicago 3:2:1 crack spread averaged U.S. $27.50/bbl compared with U.S. $26.27/bbl in the first nine months of 2011. During the third quarter of 2012, the New York Harbour 3:2:1 crack spread averaged U.S. $34.77/bbl compared with U.S. $33.72/bbl in the third quarter of 2011. In the first nine months of 2012, the New York Harbour 3:2:1 crack spread averaged U.S. $27.77/bbl compared with U.S. $26.12/bbl in the first nine 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 earnings before income taxes and net earnings from changes in certain key variables in the third quarter of 2012. The table below reflects what the effect would have been on the financial results for the third quarter of 2012 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the third 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 Third Quarter Average**	Increase	Effect on Earnings before income taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	**92.22**	*U.S. $1.00/bbl*	**61**	**0.06**	**45**	**0.05**
NYMEX benchmark natural gas price[5]	**2.81**	*U.S. $0.20/mmbtu*	**26**	**0.03**	**18**	**0.02**
WTI/Lloyd crude blend differential[6]	**21.94**	*U.S. $1.00/bbl*	**(17)**	**(0.02)**	**(12)**	**(0.01)**
Canadian light oil margins	**0.044**	*Cdn $0.005/litre*	**17**	**0.02**	**11**	**0.01**
Asphalt margins	**20.29**	*Cdn $1.00/bbl*	**12**	**0.01**	**8**	**0.01**
New York Harbour 3:2:1 crack spread	**34.77**	*U.S. $1.00/bbl*	**50**	**0.05**	**32**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**1.005**	*U.S. $0.01*	**(50)**	**(0.05)**	**(37)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 982.0 million common shares outstanding as of September 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 plays and thermal developments, 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 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 third quarter of 2012, Husky accelerated its oil resource exploration and development projects with a total of 32 horizontal wells drilled and 32 horizontal wells completed during the quarter. A total of 66 horizontal wells and two vertical wells have been drilled, and 60 horizontal wells have been completed during the first nine months of 2012. Planned oil resource play activity includes an additional 31 wells across the portfolio for the remainder of 2012.

At the Oungre Bakken project in southeast Saskatchewan, nine horizontal wells were drilled and 13 were completed in the third quarter. A total of 16 horizontal wells have been drilled and 16 completed in the first nine months of 2012. Up to seven additional wells are planned for the remainder of 2012.

In southwest Saskatchewan at the Lower Shaunavon project, one horizontal well was drilled and completed in the third quarter. Four horizontal wells have been drilled and completed in the first nine months of 2012. The 2012 drilling program is complete.

At the southwest Saskatchewan Viking project, seven horizontal wells were drilled and five horizontal wells completed in the third quarter. A total of 15 horizontal wells have been drilled and 13 completed in the first nine months of 2012. Five additional wells are planned for the remainder of 2012.

In central Alberta at the Redwater Viking project, nine horizontal wells were drilled and seven horizontal wells were completed in the third quarter. A total of 17 horizontal wells have been drilled and 15 completed in the first nine months of 2012. Nine additional wells are planned for the remainder of 2012.

In the Alliance area in south central Alberta, three horizontal wells were drilled and one horizontal well was completed in the third quarter. A total of five horizontal wells have been drilled and three completed in the first nine months of 2012. Four additional wells are planned for the remainder of 2012.

In the northern Cardium oil trend at Wapiti, two horizontal wells were drilled and completed in the third quarter. A total of five horizontal wells have been drilled and completed in the first nine months of 2012.

At the Rainbow Muskwa shale oil project, one horizontal well was drilled and three horizontal wells completed in the third quarter. A total of four horizontal wells have been drilled and four have been completed in the first nine months of 2012, including completion of a well drilled in 2011. Up to six additional wells are planned for the remainder of 2012.

At the Slater River Project in the Northwest Territories, analysis of logs and cores taken from the two vertical pilot wells drilled in the first quarter continued. The final processed version of the 220 square kilometer 3-D seismic program was received late in the third quarter and is being evaluated. Community consultations were undertaken as the first step in the submission of the land use permit applications for the upcoming winter program which includes two vertical completions of the pilot wells and construction of an all season access road to the project area.

Liquids-Rich Gas Resource Plays

At Ansell in west central Alberta, the horizontal well drilling program recommenced after a prolonged spring break-up. The third Wilrich horizontal well and fourth Cardium horizontal well in the 2012 program were drilled during the third quarter. Husky also participated in one partner-operated Wilrich horizontal well (25% working interest). One horizontal Cardium and one horizontal Wilrich well along with three vertical Cardium and two multi-zone vertical wells were completed during the quarter, all with propane fracture stimulation. Fourteen wells have been drilled and 38.5 net wells have been completed, including two partner-operated Cardium wells (25% working interest), in the first nine months of 2012. Up to four additional wells and 10 completions are planned at Ansell for the remainder of 2012.

At Kaybob, the second Duvernay horizontal well was completed and tested during the third quarter. A third well and a partner-operated well (50% working interest) are scheduled for completion in the fourth quarter. One well is currently on production.

Alkaline Surfactant Polymer Floods

Construction continued on the Fosterton, Saskatchewan alkaline surfactant polymer ("ASP") facility in the third quarter of 2012. Husky is the operator and holds a 62.4% working interest in this project. Chemical injection is expected to begin in the fourth quarter of 2012. Initial response is expected in the third quarter of 2013.

Heavy Oil

Both the 8,000 bbls/day capacity Pikes Peak South and the 3,000 bbls/day capacity Paradise Hill thermal projects reached design rates for production ahead of schedule in two months from first oil. Construction continues at the 3,500 bbls/day Sandall thermal development where site grading, foundation work and shop module fabrication are underway. This project is scheduled for first production in 2014.

The Rush Lake commercial project design, estimated at 8,000 bbls/day, is continuing, with first production anticipated in 2015. Production performance from the single well pair pilot is in line with expectations. The initial planning process is ongoing for three additional commercial thermal projects.

Horizontal development progressed in the third quarter with 49 wells drilled. Ninety nine horizontal wells have been drilled to date out of a planned 140 to 150 well program for 2012.

Ninety-seven cold heavy oil production with sand ("CHOPS") wells were drilled during the third quarter of 2012 compared to 121 CHOPS wells drilled in the third quarter of 2011. A total of 169 CHOPS wells have been drilled to date in 2012 compared to 242 wells drilled in the first nine months of 2011.

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.

Overall, the project is approximately 50% complete with all of the wells drilled and modules for both the field facilities as well as the central processing facility now arriving on site. Development work continued on the next phase of the project with early engineering work proceeding.

McMullen

During the first nine months of 2012, 32 slant wells were drilled in the primary production development project. The air injection pilot project is continuing as planned with further testing expected to occur in the fourth quarter of 2012.

Asia Pacific Region

Offshore China Exploration, Delineation and Development

The Liwan Gas Project development on Block 29/26 in the South China Sea is approximately 75% complete and on track to achieve planned first production in late 2013/early 2014. All critical path project elements remain on track.

The contract for the use of the West Hercules deep water drilling rig expired in July 2012, at which time the rig was released. The deepwater semi-submersible drilling rig, Hai Yang Shi You 981, has been engaged to continue the deep water development project.

The jacket for the shallow water central platform was transported from the Qingdao construction yard in Eastern China to its final offshore location in the South China Sea and successfully launched from the transport barge onto the ocean floor on August 30, 2012. Piling to anchor the feet of the jacket to the seabed has also been completed. The setting of the jacket is well in advance of the floatover of the topsides for the central platform which is planned for the second quarter of 2013. The Mono-ethylene Glycol Recovery Unit, a key module on the central platform, is in the final stages of completion.

Approximately 90 kilometers of the two 79-kilometer long 22” pipelines have been laid in the deep water from the gas field to the central platform and approximately 180 kilometers of pipe out of 261 kilometers 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.

Negotiations for the sale of the gas from the Liuhua 34-2 field are ongoing. Front end engineering design for the development of the Liuhua 29-1 gas field has now been completed and the Overall Development Plan is being prepared.

Indonesia Exploration and Development

Work continued on the exploration drilling program in the offshore Madura Strait Block. First gas from the Madura Strait Block is anticipated in 2014/2015. Additional new discoveries have been made which are currently being evaluated. The development plan for a combined MDA and MBH development project has also been submitted for approval to Indonesia’s regulatory body for oil and gas upstream activities.

Atlantic Region

White Rose Field and Satellite Extensions

One White Rose infill production well was placed on production in the White Rose field bringing the total number of wells at the original field to 22. The well was placed on production in mid-August after the successful completion of the SeaRose FPSO offstation program. Development drilling continued at the North Amethyst satellite field and a new production well is expected to start producing during the fourth quarter of 2012.

During the third quarter of 2012, Husky excavated a new subsea drill centre to facilitate future development of the South White Rose satellite field. In early October, Husky submitted a development plan amendment in order to incorporate gas injection into this area.

Evaluation of a wellhead platform to facilitate future development at the West White Rose satellite field continued during the third quarter.

Atlantic Region Exploration

An exploration well was spud on Husky’s Searcher prospect in the southern Jeanne d’Arc Basin. Husky will be participating with Statoil in an exploration well operated by Statoil near the Mizzen discovery in the Flemish Pass during the fourth quarter of 2012.

Offshore Greenland

A two-year extension was received on the initial phase of the exploration program for two Husky-operated exploration licenses offshore Greenland. Geological and geophysical evaluations continued on the Greenland concessions and socio-economic study work is expected to advance during the fourth quarter of 2012.

Infrastructure and Marketing

A new 300,000 barrel tank at 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 start up 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 third quarter of 2012. Mechanical completion and commissioning is expected in the fourth quarter of 2012. The project has now exceeded two 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 *($ millions)*	Three months ended Sept. 30, **2012**	2011	Nine months ended Sept. 30, **2012**	2011
Gross revenues	**1,430**	1,797	**4,783**	5,468
Royalties	**(145)**	(247)	**(504)**	(794)
Net revenues	**1,285**	1,550	**4,279**	4,674
Purchases, operating, transportation and administration expenses	**516**	474	**1,542**	1,404
Depletion, depreciation and amortization	**515**	498	**1,507**	1,417
Exploration and evaluation expense	**59**	95	**187**	276
Other expense (income)	**44**	14	**21**	(217)
Income taxes	**41**	105	**267**	466
Net earnings	**110**	364	**755**	1,328

Third Quarter

Exploration and Production net earnings in the third quarter of 2012 decreased by $254 million compared with the third quarter of 2011 due to lower oil and natural gas production, costs related to the Atlantic Region's planned turnaround activity and lower realized crude oil and natural gas prices partially offset by lower exploration and evaluation expense.

Production of 285.0 mboe/day was higher than the second quarter of 2012 but decreased by 24.1 mboe/day in the third quarter of 2012 compared to the third quarter of 2011. This was 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 and concluded on August 13, 2012, more than three weeks ahead of schedule, and the Terra Nova FPSO offstation turnaround which commenced on June 8, 2012 and is ongoing. Natural gas production was lower due to natural reservoir declines as capital investment is being directed to higher return oil and liquids-rich gas developments. These factors were partially offset by increased production in Western Canada at Bolney Celtic and at the new heavy oil thermal development projects at Pikes Peak South and Paradise Hill which added 10.3 mbbls/day to production in the third quarter of 2012. Production in the third quarter of 2011 was impacted by the Plains Rainbow pipeline outage which decreased average crude oil production by approximately 6 mbbls/day.

The average realized price for crude oil, NGL and bitumen in the third quarter of 2012 was $70.14/bbl compared with $78.70/bbl during the same period in 2011 due to lower commodity prices and wider Western Canada differentials combined with lower Brent-based production from the Atlantic Region. Realized natural gas prices averaged $2.48/mcf in the third quarter of 2012 compared with $4.12/mcf in the same period in 2011, a decline of 40%.

Nine Months

Exploration and Production net earnings in the first nine months of 2012 were $573 million lower compared with the same period in 2011. In addition to the same factors impacting the third quarter of 2012, Husky realized after-tax gains on the sale of non-core assets and an asset swap of $198 million in the first nine months of 2011. During the first nine months of 2012, average realized price for crude oil, NGL and bitumen decreased by 6% to $76.80/bbl compared with $81.58/bbl during the same period in 2011 primarily due to lower Brent-based production from the Atlantic Region and wider Western Canada differentials. Average realized natural gas prices were $2.39/mcf during the first nine months of 2012 compared with $4.00/mcf in the same period in 2011, a decline of 40%.

Average Sales Prices Realized	Three months ended Sept. 30, 2012	2011	Nine months ended Sept. 30, 2012	2011
Crude oil *($/bbl)*				
Light crude oil & NGL	**90.50**	101.16	**101.06**	103.15
Medium crude oil	**69.59**	70.81	**72.78**	73.51
Heavy crude oil	**60.58**	62.35	**63.24**	65.28
Bitumen	**60.10**	59.60	**61.30**	62.46
Total average	**70.14**	78.70	**76.80**	81.58
Natural gas average *($/mcf)*	**2.48**	4.12	**2.39**	4.00
Total average *($/boe)*	**52.52**	60.80	**56.93**	62.72

The price realized for Western Canada crude oil reflects increases in WTI offset by wider Western Canada differentials. The significant premium to WTI realized for offshore production reflects Brent prices.

Daily Gross Production	Three months ended Sept. 30, 2012	2011	Nine months ended Sept. 30, 2012	2011
Crude oil *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**29.0**	22.9	**29.6**	23.5
Medium crude oil	**23.9**	24.6	**24.3**	24.6
Heavy crude oil	**77.1**	75.1	**77.1**	74.0
Bitumen	**37.8**	23.6	**32.3**	23.8
	167.8	146.2	**163.3**	145.9
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**18.5**	46.8	**26.1**	48.3
Terra Nova – light crude oil	**–**	6.6	**3.8**	5.8
	18.5	53.4	**29.9**	54.1
China				
Wenchang – light crude oil & NGL	**7.9**	7.0	**8.3**	8.6
Crude oil and NGL *(mbbls/day)*	**194.2**	206.6	**201.5**	208.6
Natural gas *(mmcf/day)*	**544.9**	614.7	**564.4**	610.1
Total *(mboe/day)*	**285.0**	309.1	**295.6**	310.3

Crude Oil and NGL Production

Third Quarter

Crude oil and NGL production in the third quarter of 2012 decreased by 12.4 mbbls/day or 6% 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 increased production in Western Canada at Bolney Celtic and the Pikes Peak South and Paradise Hill heavy oil thermal development projects which added 10.3 mbbls/day to production during the quarter.

Nine Months

In the first nine months of 2012, crude oil and NGL production decreased by 3% compared with the same period in 2011 primarily due to the same factors impacting the third quarter of 2012.

Natural Gas Production

Third Quarter

Natural gas production in the third quarter of 2012 decreased by 69.8 mmcf or 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.

Nine Months

In the first nine months of 2012, natural gas production decreased 7% compared with the same period in 2011 primarily due to the same factors impacting the third quarter of 2012.

2012 Production Guidance

The following table shows actual daily production for the nine months ended September 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 SeaRose and Terra Nova FPSO offstation turnarounds.

		Actual Production	
	2012 Guidance	**Nine months ended September 30, 2012**	Year ended December 31, 2011
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	70 – 75	**68**	88
Medium crude oil	25 – 30	**24**	24
Heavy crude oil & bitumen	100 – 110	**110**	99
	195 – 215	**202**	211
Natural gas *(mmcf/day)*	560 – 610	**564**	607
Total *(mboe/day)*	290 – 315	**296**	312

Royalties

Third Quarter

In the third quarter of 2012, royalty rates as a percentage of gross revenues averaged 11% compared with 14% in the same period in 2011. Royalty rates in Western Canada averaged 10% in the third quarter of 2012 compared to 13% in the same period in 2011 primarily due to lower natural gas prices and enhanced oil recovery and gas cost allowance credits realized in the third quarter of 2012. Royalty rates for the Atlantic Region averaged 8% in the third quarter of 2012 down from 15% in the third quarter of 2011 due to the cost of the planned maintenance program at the Sea Rose FPSO. Royalty rates in the Asia Pacific Region averaged 23% in the third quarter of 2012 compared to 29% in the third quarter of 2011.

Nine Months

Royalty rates averaged 11% of gross revenues in the first nine months of 2012 compared with 15% in the same period in 2011. Rates in Western Canada averaged 10% compared with 13% in 2011 due to lower natural gas prices and royalty credit adjustments. Royalty rates for the Atlantic Region averaged 11% compared with 16% in the same period in 2011 due to the same factors impacting the third quarter of 2012. Royalty rates in the Asia Pacific Region averaged 24% in the first nine months of 2012 compared with 29% in the same period in 2011.

Operating Costs

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2012**	2011	**2012**	2011
Western Canada	**378**	342	**1,126**	1,056
Atlantic Region	**57**	49	**167**	131
Asia Pacific	**6**	6	**21**	18
Total	**441**	397	**1,314**	1,205
Unit operating costs *($/boe)*	**16.69**	14.62	**15.65**	13.95

Third Quarter

Total operating costs in the third quarter of 2012 were comparable to the third quarter of 2011. Total unit operating costs in the third quarter of 2012 averaged $16.69/boe compared to $14.62/boe for the same period in 2011 primarily as a result of lower production due to the planned FPSO offstation turnarounds in the Atlantic Region.

Operating costs in Western Canada averaged $16.40/boe in the third quarter of 2012 compared with $16.45/boe in the same period in 2011. Higher maintenance, servicing and labour costs and land taxes were 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 infrastructure in place.

Operating costs in the Atlantic Region averaged $33.36/boe in the third quarter of 2012 compared with $9.82/boe in the third 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 $9.10/boe in the third quarter of 2012 compared with $10.40/boe in the same period in 2011. The decrease was due to increased production combined with lower insurance, workover and oil plant costs in the third quarter of 2012 compared with the same period in 2011.

Nine Months

Total operating costs in the first nine months of 2012 were $1,314 million compared to $1,205 million in the same period in 2011 and were impacted primarily by the same factors impacting the third quarter of 2012. Operating costs in Western Canada averaged $16.10/boe in the first nine months of 2012 compared to $15.97/boe for the first nine months of 2011. Operating costs in the Atlantic Region averaged $20.42/boe in the first nine months of 2012 compared to $8.82/boe in the same period in 2011. Operating costs in the Asia Pacific Region averaged $9.42/boe in the first nine months of 2012 compared to $7.84/boe in the same period in 2011 due to lower production and higher maintenance, fuel, workover and helicopter costs.

Exploration and Evaluation Expenses

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2012**	2011	**2012**	2011
Seismic, geological and geophysical	**34**	24	**112**	102
Expensed drilling	**21**	61	**62**	121
Expensed land	**4**	10	**13**	53
Exploration and evaluation expense	**59**	95	**187**	276

Third Quarter

Exploration and evaluation expense in the third quarter of 2012 was $59 million compared with $95 million in the third quarter of 2011 due to lower drilling activity partially offset by increased seismic, geological and geophysical activity primarily in the Northwest Territories. Expensed drilling costs in the third quarter of 2011 were related to wells drilled in Canada which did not encounter economic quantities of oil and gas.

Nine Months

Exploration and evaluation expense for the first nine months of 2012 was $187 million compared to $276 million in the first nine months of 2011 primarily due to the same factors impacting the third quarter of 2012. Expensed land costs in the first nine months of 2011 included acquisition costs expensed for properties in the Columbia River Basin located in the states of Washington and Oregon.

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

Third Quarter

In the third quarter of 2012, total DD&A averaged $19.64/boe compared with $17.51/boe in the third quarter of 2011. The increased DD&A rate was primarily due to increased replacement costs across the portfolio.

Nine Months

For the first nine months of 2012, total DD&A averaged $18.61/boe compared with $16.73/boe during the same period in 2011 due to the same factors affecting the third quarter.

Exploration and Production Capital Expenditures

In the first nine months of 2012, Upstream Exploration and Production capital expenditures were $2,864 million. Capital expenditures were $1,547 million (54%) in Western Canada, $438 million (15%) in Oil Sands, $350 million (12%) in the Atlantic Region and $529 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 Sept. 30,		Nine months ended Sept. 30,	
($ millions)[1]	**2012**	2011	**2012**	2011
Exploration				
Western Canada	**43**	19	**159**	146
Atlantic Region	**35**	2	**41**	2
Asia Pacific Region	**17**	79	**17**	131
	95	100	**217**	279
Development				
Western Canada	**497**	472	**1,367**	1,130
Oil Sands	**152**	69	**438**	186
Atlantic Region	**150**	62	**309**	197
Asia Pacific Region	**175**	150	**512**	320
	974	753	**2,626**	1,833
Acquisitions				
Western Canada	**16**	–	**21**	860
	1,085	853	**2,864**	2,972

(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 completed in Western Canada, Heavy Oil and Oil Sands during the periods indicated:

	Three months ended Sept. 30,				Nine months ended Sept. 30,			
Wells Drilled	**2012**		2011		**2012**		2011	
(wells)[1]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**2**	**1**	13	8	**32**	**22**	30	21
Gas	**4**	**2**	3	3	**15**	**12**	13	13
Dry	**–**	**–**	–	–	**–**	**–**	3	3
	6	**3**	16	11	**47**	**34**	46	37
Development								
Oil	**267**	**245**	343	286	**542**	**498**	652	569
Gas	**2**	**1**	14	8	**15**	**11**	50	38
Dry	**–**	**–**	2	2	**2**	**1**	4	3
	269	**246**	359	296	**559**	**510**	706	610
Total	**275**	**249**	375	307	**606**	**544**	752	647

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

The Company drilled 544 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first nine months of 2012 resulting in 520 net oil wells and 23 net natural gas wells compared with 647 net wells resulting in 590 net oil wells and 51 net natural gas wells in the same period in 2011.

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

During the first nine months of 2012, Husky invested $1,547 million on exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $2,136 million in the first nine months of 2011. Property acquisitions totaling $21 million were completed during the first nine months of 2012 compared with $860 million in the same period in 2011. Investment in oil related exploration and development was $388 million and $335 million was invested in natural gas, including natural gas resource plays, during the first nine months of 2012 compared with $377 million for oil and $230 million for natural gas in the same period in 2011.

In addition, $172 million was spent on production optimization and cost reduction initiatives in the first nine months of 2012. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $230 million.

Capital expenditures on heavy oil projects, related to thermal projects, CHOPS drilling and horizontal drilling, were $401 million during the first nine months of 2012 compared to $396 million in the same period of 2011.

Oil Sands

During the first nine months of 2012, capital expenditures on Oil Sands projects increased to $438 million compared to $186 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 nine months of 2012.

Atlantic Region

During the first nine months of 2012, $350 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. One infill oil well was drilled in the Atlantic Region at White Rose during the first nine months of 2012.

Asia Pacific Region

Total capital expenditures of $529 million were invested in the Asia Pacific Region in the first nine months of 2012 primarily for development of the Liwan Gas Project. Four exploration wells were drilled at the Madura Strait in Indonesia during the first nine months of 2012.

Upstream Planned Turnarounds

Both the SeaRose and Terra Nova FPSOs commenced planned maintenance offstation turnarounds in the second quarter of 2012. Production from the SeaRose FPSO was shut in on May 3, 2012 affecting the White Rose, North Amethyst and West White Rose fields and operations recommenced on August 13, 2012, more than three weeks ahead of schedule. The impact to Husky's production, averaged over the entire year, is approximately 10,000 bbls/day.

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 program anticipates a return to field and reinstatement of production by the end of 2012. The impact to Husky's annual production is estimated to be approximately 4,000 bbls/day.

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 Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues	**377**	537	**1,624**	1,368
Marketing and other	**120**	21	**311**	58
Total revenues	**497**	558	**1,935**	1,426
Gross margin	**162**	52	**418**	187
Operating and administrative expenses	**21**	6	**57**	53
Depletion, depreciation and amortization	**5**	7	**16**	19
Other expenses	**–**	–	**–**	–
Income taxes	**35**	9	**88**	29
Net earnings	**101**	30	**257**	86
Commodity trading volumes managed *(mboe/day)*	**164.9**	118.8	**174.1**	168.4

Third Quarter

Infrastructure and Marketing net earnings in the third quarter of 2012 increased by $71 million compared with the third 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 to mitigate the impact of wider Western Canadian crude oil differentials. This was partially offset by higher operating and administrative expenses due to increased activity related to Keystone.

Nine Months

Infrastructure and Marketing net earnings in the first nine months of 2012 increased by $171 million compared with the same period in 2011 due to the same factors impacting the third quarter of 2012.

In the first nine months of 2012, Infrastructure and Marketing capital expenditures totalled $35 million compared to $29 million in the same period in 2011.

5.2 Downstream

Upgrader

Upgrader Earnings Summary *($ millions, except where indicated)*	Three months ended Sept. 30, **2012**	2011	Nine months ended Sept. 30, **2012**	2011
Gross revenues	**576**	586	**1,629**	1,602
Gross margin[(1)]	**153**	186	**410**	436
Operating and administration expenses[(1)]	**33**	35	**112**	113
Depreciation and amortization	**25**	26	**75**	139
Other expenses	**3**	20	**9**	48
Income taxes	**24**	27	**56**	35
Net earnings	**68**	78	**158**	101
Upgrader throughput *(mbbls/day)*[(2)]	**81.6**	75.6	**76.2**	67.4
Synthetic crude oil sales *(mbbls/day)*	**64.1**	60.7	**59.4**	54.3
Upgrading differential *($/bbl)*	**22.04**	29.87	**21.69**	28.97
Unit margin *($/bbl)*[(1)]	**25.94**	33.31	**25.28**	29.41
Unit operating cost *($/bbl)*[(1)(3)]	**4.40**	5.18	**5.29**	6.30

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

Third Quarter

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

Upgrading net earnings in the third quarter of 2012 were $68 million compared with $78 million in the same period in 2011. The decrease was primarily due to lower upgrading differentials and realized margins partially offset by higher sales volumes and decreases in other expenses due to the decrease in the fair value of the remaining upside interest payment obligations to Natural Resources Canada and the Alberta Department of Energy.

During the third quarter of 2012, the upgrading differential averaged $22.04/bbl, a decrease of $7.83/bbl or 26% compared with the same period in 2011. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. Western Canadian synthetic crude continued to trade at a discount to WTI in the third quarter of 2012 as a result of oversupply and export pipeline constraints in Western Canada compared to a premium to WTI in the same period in 2011. The average price for Husky Synthetic Blend in the third quarter of 2012 was $90.00/bbl compared to $98.22/bbl in the third quarter of 2011. The overall unit margin decreased to $25.94/bbl in the third quarter of 2012 from $33.31/bbl in the same period in 2011 primarily as a result of lower synthetic crude oil prices partially offset by lower unit energy costs.

Nine Months

Upgrading net earnings for the first nine months of 2012 were $158 million compared to $101 million in the same period in 2011 primarily due to the same factors impacting the third quarter of 2012 offset by lower depreciation and amortization in the first nine months of 2012 compared to the same period in 2011 when certain intangible costs were derecognized.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues[1]	**1,067**	1,177	**2,915**	2,949
Gross margin				
Fuel	**41**	34	**117**	113
Refining	**53**	37	**135**	130
Asphalt	**109**	116	**209**	189
Ancillary	**15**	16	**40**	38
	218	203	**501**	470
Operating and administration expenses	**59**	58	**178**	174
Depreciation and amortization	**21**	23	**62**	60
Other expenses	**–**	1	**3**	4
Income taxes	**35**	31	**66**	59
Net earnings	**103**	90	**192**	173
Number of fuel outlets[2]	**515**	544	**538**	547
Refined products sales volume				
Light oil products *(millions of litres/day)*[3]	**9.9**	9.9	**9.4**	9.5
Light oil products per outlet *(thousands of litres/day)*[3]	**19.2**	18.3	**18.3**	17.4
Asphalt products *(mbbls/day)*	**34.0**	36.4	**26.9**	25.8
Refinery throughput				
Prince George refinery *(mbbls/day)*	**11.3**	7.9	**11.0**	9.2
Lloydminster refinery *(mbbls/day)*	**28.7**	28.5	**28.3**	27.8
Ethanol production *(thousands of litres/day)*	**683.0**	652.5	**711.0**	697.6

(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.

Third Quarter

Gross margins on fuel sales were higher in the third quarter of 2012 compared with the same period in 2011 due to stronger market gasoline and diesel margins.

Higher refining gross margins in the third quarter of 2012 compared to the same period in 2011 were primarily due to increased throughput and higher gasoline and diesel prices. Included in refining gross margins are government assistance grants of $10 million in the third quarter of both 2012 and 2011.

Asphalt gross margins were lower in the third quarter of 2012 compared with the third quarter of 2011 due to lower sales volumes as a result of lower seasonal demand.

Nine Months

Refined products earnings were higher in the first nine months of 2012 than in the same period in 2011 primarily due to the same factors that impacted the third quarter of 2012. Asphalt gross margins were higher in the first nine months of 2012 due to higher market prices.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues	**2,477**	2,527	**7,626**	7,371
Gross refining margin	**456**	288	**1,004**	1,015
Operating and administration expenses	**95**	110	**293**	298
Depreciation and amortization	**52**	48	**155**	143
Other expenses	**1**	1	**4**	3
Income taxes	**113**	47	**202**	208
Net earnings	**195**	82	**350**	363
Selected operating data:				
Lima Refinery throughput *(mbbls/day)*	**153.9**	136.8	**148.0**	144.7
Toledo Refinery throughput *(mbbls/day)*	**52.7**	60.8	**61.5**	63.5
Refining margin *(U.S. $/bbl crude throughput)*	**24.36**	16.13	**17.86**	18.55
Refinery inventory *(mmbbls)*(1)	**10.1**	12.5	**10.1**	12.5

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

Third Quarter

U.S. Refining and Marketing net earnings increased in the third quarter of 2012 compared with the third quarter of 2011 due to increased realized refining margins as a result of higher market crack spreads and higher Lima Refinery throughput partially offset by turnaround activity initiated in the quarter at the Toledo Refinery. The Lima Refinery throughput increased from 136.8 mbbls/day to 153.9 mbbls/day due to less significant turnaround activity compared to the same period in 2011 where the refinery was at 85% capacity as a result of a 20-day planned isocracker outage.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were lower. The estimated FIFO impact was an increase in net earnings of approximately $34 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.

On September 13, 2012, a 30-day planned turnaround was initiated at the Toledo Refinery. The Toledo Refinery continued to be operational at 20% capacity and the impact of the outage is reflected in the third quarter results. On September 20, 2012, a 29-day aromatics turnaround commenced at the Lima Refinery. The planned outage has not had a material impact on the crude oil rate and the unit feed will be stored and reprocessed in the fourth quarter.

Salaried employees and contractors assumed operation of the Lima Refinery on May 25, 2012, maintaining optimum crude oil intake and on time and on specification delivery of products during the four month strike by the United Steelworkers. The unionized workforce returned to work on October 8, 2012. The Company has started a review process with the union for its final offer.

Nine Months

Net earnings and refining margins were lower in the first nine months of 2012 primarily due to consumption of higher Brent priced feedstock at the Lima Refinery partially offset by higher throughput at the Lima Refinery and higher market crack spreads compared with the first nine months of 2011. The estimated FIFO impact was a reduction in net earnings of approximately $6 million in the first nine months of 2012 compared to an increase in net earnings of $10 million for the same period in 2011.

Downstream Capital Expenditures

In the first nine months of 2012, Downstream capital expenditures totalled $294 million compared with $248 million in the first nine months of 2011. In Canada, capital expenditures were $94 million related to upgrades at retail stations, the Prince George Refinery and the Upgrader. In the United States, capital expenditures totalled $200 million related to U.S. refineries. At the

Lima Refinery, $95 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $105 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 shut down for 30 days during the turnaround for inspections and equipment repair.

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 Sept. 30,		Nine months ended Sept. 30,	
($ millions) income(expense)	**2012**	2011	**2012**	2011
Operating and administration expenses	**(26)**	(51)	**(99)**	(147)
Stock-based compensation	**(9)**	5	**(21)**	8
Depreciation and amortization	**(11)**	(9)	**(27)**	(25)
Other expenses	**(4)**	(6)	**(16)**	(5)
Foreign exchange gains	**16**	6	**15**	25
Interest – net	**(11)**	(30)	**(51)**	(121)
Income taxes (recovery)	**(6)**	(38)	**35**	30
Net loss	**(51)**	(123)	**(164)**	(235)

Third Quarter

The Corporate segment reported a loss of $51 million in the third quarter of 2012 compared with a loss of $123 million in the same period in 2011. Operating and administrative expenses were significantly lower in the third quarter of 2012 compared to the same period in 2011 in which the Company incurred costs related to financing projects and other initiatives. Stock-based compensation expense increased by $14 million due to new share option and performance share unit grants and a higher share price at the end of the third quarter of 2012 compared to the third quarter of 2011. There was a foreign exchange gain of $16 million during the third quarter of 2012 compared with a gain of $6 million in the same period of 2011 as a result of the strengthening Canadian dollar impacting U.S. dollar denominated debt. Interest – net decreased by $19 million compared to the third quarter of 2011 due to increased amounts of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project.

Nine Months

In the first nine months of 2012, the Corporate segment reported a loss of $164 million compared with a loss of $235 million in the same period of 2011. The decrease in corporate losses was primarily due to the same factors which impacted the third quarter.

Foreign Exchange Summary	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gains (losses) on translation of U.S. dollar denominated long-term debt	**49**	(155)	**47**	(92)
Gains (losses) on cross currency swaps	**-**	27	**2**	16
Gains (losses) on contribution receivable	**(27)**	94	**(22)**	59
Other foreign exchange gains (losses)	**(6)**	40	**(12)**	42
Net foreign exchange gains (losses)	**16**	6	**15**	25
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $1.019**	U.S. $1.037	**U.S. $0.983**	U.S. $1.005
At end of period	**U.S. $0.984**	U.S. $0.963	**U.S. $0.984**	U.S. $0.963

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 slightly in the third quarter of 2012 to $254 million from $257 million in the third quarter of 2011 resulting in an effective tax rate of 33% in both periods.

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)	**2012**	2011	**2012**	2011
Income taxes as reported	**254**	257	**644**	767
Cash taxes paid	**83**	189	**488**	242

Cash taxes paid in the third quarter of 2012 were $83 million compared with $189 million in the same period in 2011. Cash taxes for the remainder of 2012 are now expected to be approximately $110 million due to higher than expected earnings.

Corporate Capital Expenditures

In the first nine months of 2012, Corporate capital expenditures of $35 million were primarily related to computer hardware and software.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the third quarter of 2012, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At September 30, 2012, Husky had total debt of $3,887 million partially offset by cash on hand of $2,265 million for $1,622 million of net debt compared to $2,070 million of net debt as at December 31, 2011. At September 30, 2012, the Company had $3.3 billion in unused committed credit facilities, $297 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. universal 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 Sept. 30,		Nine months ended Sept. 30,	
($ millions, except ratios)	**2012**	2011	**2012**	2011
Cash flow				
Operating activities	**1,353**	1,323	**3,892**	4,057
Financing activities	**30**	(197)	**22**	451
Investing activities	**(1,187)**	(738)	**(3,477)**	(2,989)
Financial Ratios[(1)]				
Debt to capital employed *(percent)*[(2)]			**17.0**	18.6
Debt to cash flow *(times)*[(3)(4)]			**0.8**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]			**109**	115
Interest coverage ratios on long-term debt only[(3)(6)]				
Earnings			**12.3**	12.5
Cash flow			**24.4**	21.4
Interest coverage on ratios of total debt[(3)(7)]				
Earnings			**12.0**	12.1
Cash flow			**23.9**	20.6

(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

Third Quarter

In the third quarter of 2012, cash generated from operating activities was $1.4 billion compared with $1.3 billion in the third quarter of 2011 primarily due to stronger U.S. refining margins and marketing gains offset by decreased crude oil production in the Atlantic Region and lower realized commodity prices.

Nine Months

Cash generated from operating activities was $3.9 billion in the first nine months of 2012 compared with $4.1 billion in the first nine months of 2011. Slightly lower cash flow from operating activities was primarily due to the same factors affecting the third quarter of 2012 in addition to higher income taxes paid in the first nine months of 2012.

Cash Flow from Financing Activities

Third Quarter

In the third quarter of 2012, cash flow from financing activities was $30 million compared to cash flow used in financing activities of $197 million in the same period in 2011. Cash flow from financing activities was higher due to cash received from repayments of the contribution receivable, lower interest paid and lower cash dividends paid on common shares under the stock dividend program when compared to the same period in 2011.

Nine Months

Cash flow from financing activities was $22 million for the first nine months of 2012 compared to cash flow from financing activities of $451 million in 2011. In addition to the same factors impacting the third quarter of 2012, cash flow from financing activities was lower due to a preferred share issuance of $300 million and a common share issuance of $1.2 billion in the first nine months of 2011.

Cash Flow used for Investing Activities

Third Quarter

In the third quarter of 2012, cash used for investing activities was $1,187 million compared with $738 million in the same period in 2011. Cash invested in both periods was primarily for capital expenditures.

Nine Months

Cash used for investing activities was $3.5 billion in the first nine months of 2012 compared with $3.0 billion for the same period in 2011. Cash invested in both periods was primarily for capital expenditures.

6.2 Sources of Capital

Husky is currently able to fund its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of long-term debt and borrowings under committed and uncommitted credit facilities. The Company also maintains access to sufficient capital via debt markets commensurate with its balance sheet. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2012, working capital was $2,670 million compared with $2,054 million at December 31, 2011.

At September 30, 2012, Husky had unused short and long-term borrowing credit facilities totalling $3.6 billion. A total of $218 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million.

Capital Structure	**September 30, 2012**	
($ millions)	**Outstanding**	**Available[(1)]**
Total long-term debt	**3,887**	**3,597**
Common shares, preferred shares, retained earnings and other reserves	**18,934**	

[(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, $25 million in 2015, $26 million in 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 nine months ended September 30, 2012, the total value of natural gas sales to the Meridian and other cogeneration facilities was $10 million and $30 million, respectively. For the three and nine months ended September 30, 2012, the total value of obligated steam purchases from the Meridian and other cogeneration facilities was $3 million and $9 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 price, interest rate and foreign exchange risk management.

Commodity Price Risk Management

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

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

Interest Rate Risk Management

During the third quarter of 2012, the Company entered into a cash flow hedge using forward starting interest rate swap arrangements whereby the Company locked in the underlying U.S. 10-year Treasury Bond rate on U.S. $380 million to June 16, 2014, which is a portion of the Company's forecasted debt issuance on the same date. The Company entered into additional forward starting interest rate swap arrangements on October 1, 2012 whereby the Company fixed the underlying U.S. 10-year Treasury Bond rate on U.S. $120 million to June 16, 2024, which is the remainder of the Company's forecasted debt issuance on the same date. The weighted average swap rate for these forward starting swaps is 2.24%.

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

Foreign Currency Risk Management

At September 30, 2012, 81% or $3.1 billion of Husky's outstanding debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, 10% of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

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 September 30, 2012, Husky's share of this receivable was U.S. $802 million including accrued interest. The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S.

dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At September 30, 2012, Husky's share of this obligation was U.S. $1.4 billion including accrued interest. At September 30, 2012, the cost of a U.S. dollar in Canadian currency was $0.9837.

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: October 24, 2012

• common shares	982,072,392
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	30,417,393
• stock options exercisable	11,653,750

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 securities 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 September 30, 2012 are compared with results for the three months ended September 30, 2011 and the results for the nine months ended September 30, 2012 are compared with results for the nine months ended September 30, 2011. Discussions with respect to Husky's financial position as at September 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 International Accounting Standard ("IAS") 34, "Interim Financial Reporting" as issued by the International Accounting Standards Board ("IASB").
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the nine months ended September 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 nine months ended September 30:

		Three months ended Sept. 30,		Nine months ended Sept. 30,	
($ millions)		**2012**	2011	**2012**	2011
GAAP	Net earnings	**526**	521	**1,548**	1,816
	Foreign exchange	**(16)**	(4)	**(16)**	(19)
	Financial instruments	**(5)**	(12)	**(25)**	3
	Stock-based compensation	**7**	(3)	**16**	(5)
	Asset impairment and write-downs	**–**	1	**–**	1
Non-GAAP	Adjusted net earnings	**512**	503	**1,523**	1,796
	Adjusted net earnings – basic	**0.52**	0.53	**1.56**	1.97
	Adjusted net earnings – diluted	**0.52**	0.53	**1.56**	1.95

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 nine months ended September 30:

		Three months ended September 30,		Nine months ended September 30,	
($ millions)		**2012**	2011	**2012**	2011
GAAP	Cash flow – operating activities	**1,353**	1,323	**3,892**	4,057
	Settlement of asset retirement obligations	**28**	15	**85**	68
	Income taxes paid	**83**	189	**488**	242
	Interest received	**(5)**	(4)	**(24)**	(4)
	Change in non-cash working capital	**(188)**	(197)	**(845)**	(362)
Non-GAAP	Cash flow from operations	**1,271**	1,326	**3,596**	4,001
	Cash flow from operations – basic	**1.29**	1.40	**3.69**	4.38
	Cash flow from operations – diluted	**1.29**	1.39	**3.69**	4.34

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

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 result," "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 impact to the Company's production, averaged over the year, from the planned maintenance offstation turnaround of the SeaRose and Terra Nova FPSOs; the Company's forecasted debt issuance to 2024; and the expected cash taxes payable for the remainder of 2012;

- with respect to the Company's Western Canadian oil and gas resource plays: planned oil resource play exploration and development activity for the remainder of 2012, including drilling plans at Oungre Bakken, Saskatchewan Viking, Redwater Viking, Alliance, and Rainbow Muskwa, and the winter construction and completions program at the Slater River project; planned gas resource exploration and development play activity for the remainder of 2012, including drilling and completions plans at Ansell, and completions plans at Kaybob; expected timing of chemical injection at the Fosterton ASP facility; and expected timing of initial response from chemical injection at the Fosterton ASP facility;

- with respect to the Company's Heavy Oil properties: scheduled timing of first production from the Company's Sandall thermal development project; anticipated timing of first production at Rush Lake; the status of the planning for three commercial thermal projects at Rush Lake; and planned drilling program for the remainder of 2012;

- 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 testing plans at the Company's McMullen project for the remainder of 2012;

- with respect to the Company's Asia Pacific Region: anticipated timing of first gas from the Company's Madura Strait Block; planned timing of first production at the Company's Liwan Gas Project; and planned timing of the floatover of the topsides for the central platform at the Company's Liwan Gas Project;

- with respect to the Company's Atlantic Region: exploration plans in the Flemish Pass area for the remainder of 2012; socio-economic study work plans relating to the Company's Greenland concessions for the remainder of 2012; anticipated increases in royalty rates at the Company's North Amethyst and West White Rose fields; anticipated duration of a planned maintenance offstation turnaround of the Terra Nova FPSO; anticipated timing of reinstatement of production from the Terra Nova field following the planned turnaround of the Terra Nova FPSO; and anticipated timing of for a new production well to start producing at the Company's North Amethyst satellite field; and

- with respect to the Company's Downstream operating segment: anticipated timing of start up for a kerosene hydrotreater at the Company's Lima Refinery; expected timing of mechanical completion and commissioning of the Continuous Catalyst Regeneration Reformer Project at the Company's Toledo Refinery; expected timing and duration of scheduled turnarounds at the Company's Lloydminster Refinery; expected timing and duration of scheduled turnarounds at the Company's Lima Refinery; 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.