MANAGEMENT'S DISCUSSION AND ANALYSIS

February 5, 2013

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1. Summary of Quarterly Results

	Three months ended								Year ended	
Quarterly Summary	**Dec. 31**	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	December 31	
($ millions, except where indicated)	**2012**	2012	2012	2012	2011	2011	2011	2011	**2012**	2011
Production (mboe/day)	**319.3**	285.0	281.9	319.9	318.9	309.1	311.6	310.4	**301.5**	312.5
Gross revenues[1]	**5,945**	5,451	5,748	5,984	5,888	6,079	6,043	5,072	**23,128**	23,082
Net earnings	**474**	526	431	591	408	521	669	626	**2,022**	2,224
Per share – Basic	**0.48**	0.53	0.44	0.61	0.42	0.55	0.73	0.70	**2.06**	2.40
Per share – Diluted	**0.48**	0.53	0.43	0.60	0.42	0.53	0.71	0.70	**2.06**	2.34
Cash flow from operations[2]	**1,414**	1,271	1,153	1,172	1,197	1,326	1,511	1,164	**5,010**	5,198
Per share – Basic	**1.44**	1.29	1.18	1.21	1.25	1.40	1.68	1.31	**5.13**	5.63
Per share – Diluted	**1.44**	1.29	1.17	1.20	1.24	1.39	1.67	1.30	**5.13**	5.58

(1) Gross revenues have been recast to reflect a change in presentation for trading activities. Refer to Section 9 and Note 3 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

- Fourth quarter production of 319.3 mboe/day was 34.3 mboe/day higher than the third quarter of 2012 and comparable to the same period in 2011 with:
  - Production in the Atlantic Region's White Rose and Satellite fields reaching expected post-turnaround levels of 44.9 mboe/day in the quarter;
  - Increased crude oil production in Western Canada from heavy oil thermal projects; and
  - Decreased natural gas production due to natural reservoir declines and limited re-investment as capital is being directed to higher return oil and liquids-rich gas developments.

- Net earnings were higher in the fourth quarter of 2012 compared to the fourth quarter of 2011, with:
  - Higher throughput at the Upgrader and in U.S. Refining and Marketing;
  - Stronger realized U.S. refining margins due to favourable market crack spreads;
  - Higher Infrastructure and Marketing earnings from the utilization of infrastructure to transport crude oil from Canada to the U.S. mitigating the impact of wider Western Canada crude oil differentials; and
  - Lower realized commodity prices in Upstream Exploration and Production.
- Cash flow from operations in the quarter increased compared to the fourth quarter of 2011 mainly due to higher throughput and margins in Downstream and strong Infrastructure and Marketing earnings, partially offset by lower realized commodity prices in Upstream Exploration and Production**.**

Key Projects

- The Liwan Gas Project is progressing on track and was approximately 80% complete at the end of the year. The Overall Development Plan for the Liwan 3-1 field development was approved by the Chinese Government in 2012 and seven field development wells are now ready for production. All other critical path items remain on track.
- The 2012 exploration drilling program on the Madura Strait Block concluded in October with four new discoveries being made as a result of a five well exploration drilling program. These discoveries are now under evaluation for commercial development.
- A joint venture agreement was signed with a 75% participation in an exploration block offshore Taiwan of approximately 10,000 square kilometers in water depths of 200 to 3,000 meters.
- At the Sunrise Energy Project, all significant contracts for Phase 1, including the Central Processing Facility, have now been converted to lump sum. Over 85% of the project's costs are now fixed and the project is approximately 60% complete.
- At the North Amethyst satellite field, a fourth production well was completed and brought online.
- Terra Nova non-operated FPSO initial production commenced following the turnaround in 2012. Initial production is below expectations due to operational issues.
- The new build rig West Mira has been contracted for future operations in the Atlantic Region. The rig is currently under construction and is expected to support a range of development and exploration opportunities commencing in 2015.
- The Searcher exploration well in the Atlantic region did not encounter hydrocarbons and was expensed in the quarter.
- Average production levels of approximately 12,000 bbls/day at Pikes Peak South and 5,000 bbls/day at Paradise Hill heavy oil thermal projects were achieved in the fourth quarter.
- At the 3,500 bbls/day Sandall heavy oil thermal development, construction is approximately 40% complete and initial drilling has commenced. This project is scheduled for first production in 2014.
- Resource play development progressed in Western Canada with 26 horizontal oil wells and six liquids-rich gas wells drilled in the fourth quarter and 11 and 14 well completions, respectively.

Financial

- Dividends on common shares of $295 million for the third quarter of 2012 were declared during the fourth quarter of 2012 of which $293 million and $2 million were paid in cash and common shares, respectively, on January 2, 2013.

2. Business Environment

Average Benchmarks		Year ended Dec. 31 2012	Year ended Dec. 31 2011	Three months ended Dec. 31 2012	Sept. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011
WTI crude oil(1)	*(U.S. $/bbl)*	**94.21**	95.12	**88.18**	92.22	93.49	102.93	94.06
Brent crude oil(2)	*(U.S. $/bbl)*	**111.54**	111.27	**110.00**	109.48	109.29	118.49	109.31
Western Canada Select(3)	*(U.S. $/bbl)*	**73.18**	77.97	**70.07**	70.49	70.63	81.51	83.57
Canadian light crude 0.3% sulphur	*($/bbl)*	**86.57**	95.32	**84.43**	84.89	84.37	92.70	97.70
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**62.89**	67.61	**59.55**	61.91	60.12	69.95	76.44
NYMEX natural gas(4)	*(U.S. $/mmbtu)*	**2.79**	4.04	**3.40**	2.81	2.21	2.74	3.55
NIT natural gas	*($/GJ)*	**2.28**	3.48	**2.90**	2.08	1.74	2.39	3.27
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.46**	17.44	**18.29**	21.94	23.58	21.99	10.73
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**31.36**	25.26	**35.06**	34.77	29.21	26.31	22.05
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**27.63**	24.65	**28.00**	35.18	27.85	19.35	19.06
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.001**	1.011	**1.009**	1.005	0.990	0.999	0.977
Canadian $ Equivalents								
WTI crude oil(5)	*($/bbl)*	**94.12**	94.09	**87.39**	91.76	94.43	103.03	96.27
Brent crude oil(5)	*($/bbl)*	**111.43**	110.06	**109.02**	108.94	110.39	118.61	111.88
WTI/Lloyd crude blend differential(5)	*($/bbl)*	**21.44**	17.25	**18.13**	21.83	23.82	22.01	10.98
NYMEX natural gas(5)	*($/mmbtu)*	**2.79**	4.00	**3.37**	2.79	2.23	2.74	3.63

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

The price Husky Energy Inc. ("Husky" or "the Company") receives for production from Western Canada is primarily driven by the price of 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 ended 2012 at U.S. $94.19/bbl, decreasing from U.S. $98.83/bbl on December 31, 2011. The price of WTI averaged U.S. $88.18/bbl in the fourth quarter of 2012 compared with U.S. $94.06/bbl in the fourth quarter of 2011. The price of WTI averaged U.S. $94.21/bbl in 2012 compared with U.S. $95.12/bbl in 2011. The price of Brent ended 2012 at U.S. $111.66/bbl, increasing from U.S. $106.51/bbl on December 31, 2011. The price of Brent averaged U.S. $110.00/bbl in the fourth quarter of 2012 compared with U.S. $109.31/bbl in the fourth quarter of 2011. The price of Brent averaged U.S. $111.54/bbl in 2012 compared with U.S. $111.27/bbl in 2011.

In the fourth quarter of 2012, the price of WTI in U.S. dollars decreased by 6% compared to 9% in Canadian dollars when compared to the same period in 2011. In 2012, the price of WTI in U.S. dollars decreased by 1% compared to nil in Canadian dollars when compared to 2011 with the weakening of the Canadian dollar versus the U.S. dollar, offsetting the movement in crude oil prices.

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 fourth quarter of 2012, 53% of Husky's crude oil production was heavy oil or bitumen compared with 47% in the fourth quarter of 2011. The light/heavy crude oil differential averaged U.S. $18.29/bbl or 21% of WTI in the fourth quarter of 2012 compared with U.S. $10.73/bbl or 11% of WTI in the fourth quarter of 2011. In 2012, 54% of Husky's crude oil production was heavy oil or bitumen compared with 47% in 2011. The increase in the 2012 heavy oil to total crude oil production weighting was due to lower light crude oil production from the Atlantic Region where the Company completed the planned FPSO offstation turnarounds and increased production from new heavy oil thermal projects. The light/heavy crude oil differential averaged U.S. $21.46/bbl or 23% of WTI in 2012 compared with U.S. $17.44/bbl or 18% of WTI in 2011.

The near-month natural gas contract price quoted on the NYMEX ended 2012 at U.S. $3.35/mmbtu compared with U.S. $2.99/mmbtu at December 31, 2011. During the fourth quarter of 2012, the NYMEX near-month contract price of natural gas averaged U.S. $3.40/mmbtu compared with U.S. $3.55/mmbtu in the fourth quarter of 2011, a decline of 4%. During 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.79/mmbtu compared with U.S. $4.04/mmbtu during 2011, a decline of 31%.

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.

The Canadian dollar ended 2011 at U.S. $0.983 and closed at U.S. $1.005 at December 31, 2012. In the fourth quarter of 2012, the Canadian dollar averaged U.S. $1.009, strengthening by 3% compared with U.S. $0.977 during the fourth quarter of 2011. In 2012, the Canadian dollar averaged U.S. $1.001, weakening by 1% compared with U.S. $1.011 during 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 reflect the actual crude purchase costs or product configuration of a specific refinery.

During the fourth quarter of 2012, the Chicago 3:2:1 crack spread averaged U.S. $28.00/bbl compared with U.S. $19.06/bbl in the fourth quarter of 2011. In 2012, the Chicago 3:2:1 crack spread averaged U.S. $27.63/bbl compared with U.S. $24.65/bbl in 2011. During the fourth quarter of 2012, the New York Harbour 3:2:1 crack spread averaged U.S. $35.06/bbl compared with U.S. $22.05/bbl in the fourth quarter of 2011. In 2012, the New York Harbour 3:2:1 crack spread averaged U.S. $31.36/bbl compared with U.S. $25.26/bbl in 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 fourth quarter of 2012. The table below reflects what the effect would have been on the financial results for the fourth quarter of 2012 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the fourth 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 Fourth 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]	**88.18**	*U.S. $1.00/bbl*	**73**	**0.07**	**54**	**0.05**
NYMEX benchmark natural gas price[5]	**3.40**	*U.S. $0.20/mmbtu*	**19**	**0.02**	**14**	**0.01**
WTI/Lloyd crude blend differential[6]	**18.29**	*U.S. $1.00/bbl*	**(19)**	**(0.02)**	**(14)**	**(0.01)**
Canadian light oil margins	**0.04**	*Cdn $0.005/litre*	**16**	**0.02**	**12**	**0.01**
Asphalt margins	**14.40**	*Cdn $1.00/bbl*	**9**	**0.01**	**7**	**0.01**
New York Harbour 3:2:1 crack spread	**35.06**	*U.S. $1.00/bbl*	**54**	**0.05**	**34**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**1.009**	*U.S. $0.01*	**(51)**	**(0.05)**	**(38)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 982.2 million common shares outstanding as of December 31, 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 and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward thermal developments and resource plays, while advancing its three major growth pillars in the Asia Pacific Region, Oil Sands and in the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

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 the 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, diluent and natural gas (Infrastructure and Marketing). The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore Greenland, offshore China 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 supported the repositioning of the Heavy Oil and Western Canada foundation by accelerating near-term production growth and advancing Husky's three major growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

4.1 Upstream

Western Canada (Excluding Heavy Oil and Oil Sands)

Oil Resource Plays

During the fourth quarter of 2012, a total of 25 horizontal wells were drilled and 11 horizontal wells were completed across the oil resource project portfolio. A total of 93 horizontal wells and two vertical wells were drilled and 78 horizontal wells were completed in 2012.

The following table summarizes the oil resource play drilling and completion activity for the three months and year ended December 31, 2012:

Oil Resource Plays [(1)]		Three months ended Dec. 31,		Year ended Dec. 31,	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	6	5	22	21
Lower Shaunavon	S.W. Saskatchewan	—	—	4	4
Viking [(2)]	Alberta and S.W. Saskatchewan	11	6	50	45
N.Cardium	Wapiti, Alberta	—	—	5	5
Rainbow Muskwa	N. Alberta	8	—	12	3
Slater River	Northwest Territories	—	—	2	—
Total Gross		25	11	95	78
Total Net		25	11	89	74

(1) Excludes service/stratigraphic test wells for evaluation purposes. All activity was horizontal except Slater River N.W.T. vertical wells.
(2) Viking is comprised of project activity at Redwater in C. Alberta, Alliance in S.E. Alberta and drilling in S.W. Saskatchewan.

In the fourth quarter of 2012, preparations continued for the winter 2012/2013 program at the Slater River project in the Northwest Territories where two vertical wells were drilled earlier in 2012. Approvals were received during the quarter for the completion of these two wells and for a baseline groundwater study. The approval for the all-season access road was received in January 2013. The results from the 2013 work program will determine the next steps at Slater River.

Liquids-Rich Gas Resource Plays

In the fourth quarter of 2012, six liquids-rich horizontal gas wells were drilled and 14 gas wells were completed across the liquids-rich gas portfolio. A total of 23 wells were drilled and 58 wells were completed in 2012.

The following table summarizes the liquids-rich gas drilling and completion activity for the three months and year ended December 31, 2012:

Liquids-Rich Gas Plays[(1)]		Three months ended Dec. 31,		Year ended Dec. 31	
Project	Location	Gross Wells Drilled	Gross Wells Completed	Gross Wells Drilled	Gross Wells Completed
Ansell	West Central Alberta	5	12	18	53
Duvernay	West Central Alberta	1	1	4	3
Montney	West Central Alberta	—	1	1	2
Total Gross		6	14	23	58
Total Net		5	14	21	56

(1) *Excludes service/stratigraphic test wells for evaluation purposes. Liquids-rich gas drilling activity in 2012 was mainly horizontal wells. Completion activity includes legacy vertical wells. Types of drilling include Wilrich and Cardium horizontals and vertical single and multi zone wells.*

Horizontal drilling continued at Ansell during the fourth quarter. At the end of 2012, eight horizontal wells were on production and two additional rigs were mobilized in December to commence the winter vertical multi-zone well appraisal drilling program.

At the Duvernay play, a third horizontal well was completed in the quarter and commenced production in January 2013. A previously completed well is expected to be tied-in during the first quarter of 2013. In December, the first well on a four well pad of horizontal wells was spud, and drilling will continue in 2013.

The second of two Montney horizontal wells was completed in the fourth quarter.

Alkaline Surfactant Polymer Floods

Construction was completed on the Fosterton, Saskatchewan Alkaline Surfactant Polymer ("ASP") facility in the fourth quarter of 2012. Husky is the operator and holds a 62.4% working interest in this project. Chemical injection has commenced with initial production response expected in the second half of 2013.

Heavy Oil

Average production levels of approximately 12,000 bbls/day at Pikes Peak South and 5,000 bbls/day at Paradise Hill heavy oil thermal projects were achieved during the fourth quarter of 2012.

Construction is approximately 40% complete at the 3,500 bbls/day Sandall thermal development project and initial drilling has commenced. First production is scheduled in 2014.

Design and initial site work is continuing at the 10,000 bbls/day Rush Lake commercial project with first production anticipated in 2015. Production performance from the first single well pair pilot is in line with expectations and a second well pair pilot is planned to commence production in the second quarter of 2013. Initial planning is ongoing for three additional commercial thermal projects.

Horizontal development progressed in the fourth quarter with 45 wells drilled which completed the 144 well program for 2012 and compares to 130 wells drilled in 2011. In 2013, 140 wells are planned.

Eighty-one Cold Heavy Oil Production with Sand ("CHOPS") wells were drilled during the fourth quarter of 2012 compared to 90 CHOPS wells drilled in the fourth quarter of 2011. A total of 250 CHOPS wells were drilled in 2012 compared to 305 wells drilled in 2011. In 2013, 200 CHOPS wells are planned.

Asia Pacific Region

China

The Overall Development Plan for the Liwan Gas Project development on Block 29/26 in the South China Sea has been approved by the Chinese Government. The development project is now more than 80% complete and remains on track to achieve planned first production in late 2013/early 2014.

Two further upper completions in the Liwan 3-1 gas field were installed and flow tested successfully at the expected production rates bringing the total of fully ready production wells to seven.

During the 2012 construction season, two approximately 90-kilometer long 22” pipelines were laid in the deep water from the gas field to the central platform. In addition, approximately 190 kilometers of pipe out of 261 kilometers was laid from the platform through to the onshore gas plant. Pipe laying activity is planned to resume in March 2013.

Fabrication of the platform topsides is progressing on track in preparation for the floatover to the central platform final location planned in the second quarter of 2013. The Monoethylene Glycol Recovery Unit has been delivered to the Qingdao, Eastern China topsides construction site and the approximate 850 tonne unit has been elevated and set into its final installation position on the upper deck. Generators and compressors have also been positioned on the deck. Construction of control rooms, living areas and other facilities are in their final stages.

Construction of the onshore gas plant is also progressing on schedule. Site preparations and foundations are largely complete. Nine of ten spherical liquids storage tanks are in place and the construction of pipe racks for transporting gas through the site is progressing. Construction of control and administrative buildings as well as living areas has commenced.

Negotiations for the sale of the gas from the Liuhua 34-2 and Liuhua 29-1 fields are ongoing.

Indonesia

The 2012 exploration drilling program on the Madura Strait Block concluded in October with four new discoveries being made as a result of a five well exploration drilling program. These discoveries are now under evaluation for commercial development.

In November, the functions of the Indonesian oil and gas regulator, BP Migas, were transferred to the Energy and Mineral Resources Ministry and to a newly established industry regulator, SKK Migas. As agreed with the new regulator, a re-tender process for the BD field FPSO was initiated with pre-qualification responses due in January 2013. The development plan for a combined MDA and MBH development project was approved by the regulator in 2013. First gas from the Madura Strait Block is anticipated for the 2015 time frame.

Taiwan

In December, Husky signed a joint venture contract with CPC Corporation, Taiwan for an exploration block in the South China Sea. The exploration block is located 100 kilometers southwest of the island of Taiwan and covers approximately 10,000 square kilometers, in water depths of 200 to 3,000 meters. Under the joint venture contract, Husky has an obligation to carry out seismic surveys to assess the petroleum potential of the exploration block within the first two years, with an option to drill at least one exploration well in subsequent exploration periods. Husky holds a 75% working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50% interest.

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 track for first production in 2014.

Substantial cost certainty related to the first phase of the Sunrise Energy Project was achieved in the fourth quarter of 2012 with the conversion of the lump sum contract for the Central Processing Facility ("CPF"). Over 85% of the $2.7 billion estimated costs for Phase 1 are now fixed and incorporate all significant contract conversions and design improvements. To date, approximately 60% of the project's total cost estimate has been spent.

The CPF is approaching 50% completion with piling substantially completed and foundation work proceeding at the site. Major equipment continues to be delivered and placed into position with approximately half of the modules fabricated and moved to site. Construction of the field facilities is now more than 75% complete with significant activity currently underway, including pipelining in the field and fabrication in the module shops.

Development work continues on the next phase of the Sunrise Energy Project with the Design Basis Memorandum expected to be completed in 2013.

Tucker

Drilling commenced on five new Grand Rapids well pairs at the Tucker Lake Oil Sands Project. Fourth quarter production was maintained at approximately 10,000 bbls/day.

Saleski

A regulatory application for a bitumen carbonate pilot is anticipated to be filed in 2013.

McMullen

During the fourth quarter of 2012, 32 slant wells were equipped and placed on production in the cold production development project. Drilling operations for the 2013 program commenced with a total of 15 new slant development wells drilled before the end of 2012. At the end of 2012, production from McMullen was 4,600 bbls/day. At the air injection pilot project, first production was achieved from the horizontal producer with on-going testing continuing as planned.

Atlantic Region

White Rose Field and Satellite Extensions

At the North Amethyst field, a fourth production well was completed and brought online in the fourth quarter and drilling on a supporting water injector is planned for the first quarter of 2013. An application to develop the deeper Hibernia level formation at North Amethyst is undergoing regulatory review.

Review of the White Rose Extension Project continued on two fronts. At the South White Rose Extension, a development plan amendment was submitted to the regulator and a temporary guide base was installed at the South White Rose Extension drill centre. Development drilling is anticipated to begin in early 2013.

Evaluation of a wellhead platform to facilitate future development at the West White Rose satellite field continued during the fourth quarter of 2012. Supporting regulatory filings were submitted for an environmental assessment of the wellhead platform concept. A decision on a preferred development option is expected in the first half of 2013.

Drilling at the Searcher prospect in the southern Jeanne d'Arc Basin did not encounter commercial hydrocarbons and the well was expensed in the fourth quarter.

Husky and Seadrill entered into a five-year contract for the use of Seadrill's new harsh environment semi-submersible rig, West Mira. The contract will begin when construction of the West Mira has been completed, which is expected in 2015.

In November 2012 the Company acquired a 40% interest in a new exploration license in the Flemish Pass which is adjacent to existing holdings in the Jeanne d'Arc Basin. Future exploration is currently being evaluated.

Offshore Greenland

Geotechnical evaluations continued on the Greenland concessions.

4.2 Downstream

Lima, Ohio Refinery

The Lima, Ohio Refinery continues to progress reliability and profitability improvement projects. Construction of the 20 mbbls/day kerosene hydrotreater is approximately 80% complete. The kerosene hydrotreater, which will increase on-road diesel and jet fuel production volumes, is expected to be operational in the first quarter of 2013.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is progressing as planned. Mechanical completion was achieved in the fourth quarter and start up is expected in the first quarter of 2013. 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 Dec. 31, 2012	2011	Year ended Dec. 31, 2012	2011
Gross revenues	**1,764**	2,051	**6,547**	7,519
Royalties	**(189)**	(331)	**(693)**	(1,125)
Net revenues	**1,575**	1,720	**5,854**	6,394
Purchases, operating, transportation and administration expenses	**549**	562	**2,091**	1,966
Depletion, depreciation, amortization and impairment	**614**	601	**2,121**	2,018
Exploration and evaluation expense	**163**	194	**350**	470
Other expense (income)	**(53)**	20	**(32)**	(197)
Income taxes	**78**	90	**345**	556
Net earnings	**224**	253	**979**	1,581

Fourth Quarter

Exploration and Production net earnings in the fourth quarter of 2012 decreased by $29 million compared with the fourth quarter of 2011 due to lower realized crude oil and natural gas prices partially offset by lower exploration and evaluation expense and higher other income related to the realization of net profits on inventory drawdowns during the quarter.

Production of 319.3 mboe/day in the fourth quarter of 2012 was comparable to production in the fourth quarter of 2011. Crude oil production increased in Western Canada at Bolney Celtic and at the heavy oil thermal projects at Pikes Peak South and Paradise Hill offset by natural reservoir declines in natural gas properties as capital investment is being directed to higher return oil and liquids-rich gas developments. Decreased production in the Atlantic Region in the fourth quarter of 2012 compared to the same period in 2011 was attributed to the Terra Nova FPSO turnaround, which continued into the fourth quarter, and lower production at the White Rose main field due to natural declines in the reservoir partially offset by production from satellite fields.

The average realized price for crude oil, NGL and bitumen in the fourth quarter of 2012 was $72.17/bbl compared with $89.79/bbl during the same period in 2011 due to lower prices for WTI combined with wider Western Canada differentials. Realized natural gas prices averaged $3.25/mcf in the fourth quarter of 2012 compared with $3.53/mcf in the same period in 2011, a decline of 8%.

Twelve Months

Exploration and Production net earnings in 2012 decreased by $602 million compared to 2011 mainly due to lower realized crude oil and natural gas prices and lower production in the Atlantic Region as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs offset by increased production in Western Canada. In addition, other income in 2011 includes after-tax gains on the sale of non-core assets in the amount of $198 million.

During 2012, the average realized price for crude oil, NGL and bitumen decreased by 10% to $75.50/bbl compared with $83.73/bbl during 2011 primarily due to lower Brent-based production from the Atlantic Region and wider Western Canada differentials. Average realized natural gas prices were $2.60/mcf during 2012 compared with $3.89/mcf in 2011, a decline of 33%.

Average Sales Prices Realized	Three months ended Dec. 31, 2012	2011	Year ended Dec. 31, 2012	2011
Crude oil *($/bbl)*				
Light crude oil & NGL	**94.91**	106.61	**99.22**	104.06
Medium crude oil	**67.55**	85.83	**71.51**	76.59
Heavy crude oil	**57.90**	76.37	**61.91**	68.13
Bitumen	**55.74**	74.19	**59.49**	65.75
Total average	**72.17**	89.79	**75.50**	83.73
Natural gas average *($/mcf)*	**3.25**	3.53	**2.60**	3.89
Total average *($/boe)*	**57.77**	68.35	**57.16**	64.17

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

Daily Gross Production	Three months ended Dec. 31, 2012	2011	Year ended Dec. 31, 2012	2011
Crude oil *(mbbls/day)*				
Western Canada				
Light crude oil & NGL	**31.9**	28.8	**30.1**	24.8
Medium crude oil	**23.2**	24.3	**24.1**	24.5
Heavy crude oil	**76.0**	75.8	**76.9**	74.5
Bitumen	**46.7**	27.4	**35.9**	24.7
	177.8	156.3	**167.0**	148.5
Atlantic Region				
White Rose and Satellite Fields – light crude oil	**44.9**	49.6	**30.8**	48.7
Terra Nova – light crude oil	**0.8**	5.0	**3.0**	5.6
	45.7	54.6	**33.8**	54.3
China				
Wenchang – light crude oil & NGL	**8.5**	8.3	**8.4**	8.5
	232.0	219.2	**209.2**	211.3
Natural gas (mmcf/day)	**523.7**	597.9	**554.0**	607.0
Total (mboe/day)	**319.3**	318.9	**301.5**	312.5

Crude Oil and NGL Production

Fourth Quarter

Crude oil and NGL production in the fourth quarter of 2012 increased by 12.8 mbbls/day or 6% compared with the same period in 2011 due to higher production in Western Canada at the Pikes Peak South and Paradise Hill heavy oil thermal projects partially offset by lower production in the Atlantic Region due to the Terra Nova FPSO turnaround, which continued into the fourth quarter, and lower production at White Rose and Satellite fields due to natural declines in the reservoir.

Twelve Months

In 2012, crude oil and NGL production decreased by 1% compared with 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, largely offset by increased production in Western Canada heavy oil thermal projects.

Natural Gas Production

Fourth Quarter

Natural gas production in the fourth quarter of 2012 decreased by 74.2 mmcf or 12% compared to 2011 due to natural reservoir declines in mature properties as capital investment is being directed to higher return oil and liquids-rich developments.

Twelve Months

In 2012, natural gas production decreased 9% compared with 2011 primarily due to the same factors impacting the fourth quarter of 2012.

2012 Production Guidance

The following table shows actual daily production for the year ended December 31, 2012 and the year ended December 31, 2011, as well as the production guidance for 2012. Guidance and actual production for 2012 reflected the impacts of the SeaRose and Terra Nova FPSO offstation turnarounds.

	2012 Guidance	Actual Production Year ended December 31, 2012	 Year ended December 31, 2011
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	70 – 75	**72**	88
Medium crude oil	25 – 30	**24**	24
Heavy crude oil & bitumen	100 – 110	**113**	99
	195 – 215	**209**	211
Natural gas *(mmcf/day)*	560 – 610	**554**	607
Total (mboe/day)	290 – 315	**302**	312

Royalties

Fourth Quarter

In the fourth quarter of 2012, royalty rates as a percentage of gross revenues averaged 11% compared with 17% in the same period in 2011. Royalty rates in Western Canada averaged 11% in the fourth quarter of 2012 compared to 14% in the same period in 2011 primarily due to price sensitivity impacts on royalty rates associated with lower commodity pricing in 2012 combined with an increase in enhanced oil recovery credits realized for Husky thermal bitumen production in the fourth quarter of 2012. Royalty rates for the Atlantic Region averaged 10% in the fourth quarter of 2012 down from 19% in the fourth quarter of 2011 due to higher eligible costs associated with the SeaRose offstation and lower Terra Nova production which is subject to higher royalty rates. Royalty rates in the Asia Pacific Region averaged 22% in the fourth quarter of 2012 compared to 31% in the same period of 2011 mainly due to reductions in windfall profit taxes that became effective in November of 2011.

Twelve Months

Royalty rates averaged 11% of gross revenues in 2012 compared with 16% in 2011. Rates in Western Canada averaged 10% compared with 14% in 2011 due to lower natural gas prices and royalty credit adjustments. Royalty rates for the Atlantic Region averaged 11% in 2012 compared with 17% in 2011 due to the same factors impacting the fourth quarter of 2012. Royalty rates in the Asia Pacific Region averaged 24% in 2012 compared with 30% in 2011 mainly due to reductions in windfall profit taxes.

Operating Costs

	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2012**	2011	**2012**	2011
Western Canada	**445**	429	**1,571**	1,485
Atlantic Region	**45**	43	**212**	174
Asia Pacific	**10**	7	**31**	25
Total	**500**	479	**1,814**	1,684
Unit operating costs *($/boe)*	**15.05**	14.17	**15.49**	14.01

Fourth Quarter

Total operating costs in the fourth quarter of 2012 were $500 million compared to $479 million in the same period of 2011. Total unit operating costs in the fourth quarter of 2012 averaged $15.05/boe compared to $14.17/boe for the same period in 2011 primarily as a result of lower production in the Atlantic Region due to the planned FPSO offstation turnarounds.

Operating costs in Western Canada averaged $15.90 /boe in the fourth quarter of 2012 compared with $15.53 /boe in the same period in 2011. Higher fuel and labour costs were partially offset by lower treating and maintenance costs.

Operating costs in the Atlantic Region averaged $10.73 /boe in the fourth quarter of 2012 compared with $8.54 /boe in the same period 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 $12.01 /boe in the fourth quarter of 2012 compared with $9.18 /boe in the same period in 2011. The increase was due to higher maintenance and workover costs in the fourth quarter of 2012 compared to the same period in 2011.

Twelve Months

Total operating costs in 2012 were $1,814 million compared to $1,684 million in 2011 and were impacted primarily by the same factors impacting the fourth quarter of 2012. Operating costs in Western Canada averaged $15.45 /boe in 2012 compared to $15.35 /boe in 2011. Operating costs in the Atlantic Region averaged $17.12 /boe in 2012 compared to $8.75 /boe in 2011 due to the same factors impacting the fourth quarter of 2012. Operating costs in the Asia Pacific Region averaged $10.08 /boe in 2012 compared to $8.08 /boe in 2011 due to higher maintenance, fuel, workover and helicopter costs.

Exploration and Evaluation Expenses

	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2012**	2011	**2012**	2011
Seismic, geological and geophysical	**34**	68	**146**	170
Expensed drilling	**126**	124	**188**	245
Expensed land	**3**	2	**16**	55
Exploration and evaluation expense	**163**	194	**350**	470

Fourth Quarter

Exploration and evaluation expense in the fourth quarter of 2012 was $163 million, including $79 million of drilling costs for the Searcher well in the Atlantic Region, compared with $194 million in the fourth quarter of 2011. The decrease in seismic and geological expense was primarily due to a shift in focus in 2012 to more development activities in Western Canada compared with 2011.

Twelve Months

Exploration and evaluation expense for 2012 was $350 million compared to $470 million in 2011 primarily due to the same factors impacting the fourth quarter of 2012. Additionally, expensed drilling and land costs in 2011 included acquisition and drilling costs expensed for properties in the Columbia River Basin located in the states of Washington and Oregon.

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

Fourth Quarter

In the fourth quarter of 2012, total DD&A averaged $20.81/boe compared with $20.47/boe in the fourth quarter of 2011.

Twelve Months

In 2012, total DD&A averaged $19.20/boe compared with $17.69/boe in 2011 as the Company shifts focus to higher capital investments in oil and liquids rich natural gas properties with higher netbacks than natural gas developments.

Exploration and Production Capital Expenditures

In 2012, Upstream Exploration and Production capital expenditures were $4,106 million. Capital expenditures were $2,288 million (56%) in Western Canada, $658 million (16%) in Oil Sands, $413 million (10%) in the Atlantic Region and $747 million (18%) in the Asia Pacific Region. Husky's major projects remain on budget and on schedule.

Exploration and Production Capital Expenditures	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)[1]	**2012**	2011	**2012**	2011
Exploration				
Western Canada	**79**	87	**238**	233
Atlantic Region [2]	**(28)**	—	**13**	2
Asia Pacific Region	**5**	37	**22**	168
	56	124	**273**	403
Development				
Western Canada	**662**	653	**2,029**	1,787
Oil Sands	**220**	81	**658**	263
Atlantic Region	**91**	61	**400**	258
Asia Pacific Region	**213**	226	**725**	546
	1,186	1,021	**3,812**	2,854
Acquisitions				
Western Canada	**—**	14	**21**	874
	1,242	1,159	**4,106**	4,131

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *The Company wrote-off $79 million related to a Searcher well in the fourth quarter of 2012 of which $37 million had been capitalized at the end of the third quarter. Exploration capital expenditures in the Atlantic Region excluding this write-off were $9 million in the fourth quarter of 2012.*

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 Dec. 31,				Year ended Dec. 31,			
Wells Drilled		**2012**		2011		**2012**		2011
(wells) [1]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration								
Oil	**15**	**8**	20	19	**47**	**30**	50	40
Gas	**4**	**—**	11	11	**19**	**12**	24	24
Dry	**—**	**—**	—	—	**—**	**—**	3	3
	19	**8**	31	30	**66**	**42**	77	67
Development								
Oil	**233**	**217**	228	196	**775**	**715**	880	765
Gas	**8**	**6**	7	4	**23**	**17**	57	42
Dry	**3**	**3**	—	1	**5**	**4**	4	4
	244	**226**	235	201	**803**	**736**	941	811
Total	**263**	**234**	266	231	**869**	**778**	1,018	878

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

The Company drilled 778 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2012 resulting in 745 net oil wells and 29 net natural gas wells compared with the drilling of 878 net wells resulting in 805 net oil wells and 66 net natural gas wells in 2011.

Capital expenditures for wells drilled in Western Canada increased substantially in 2012 compared with 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 2012, Husky invested $2,288 million on exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $2,894 million in 2011. Property acquisitions totalling $21 million were completed in 2012 compared with $874 million in 2011. Investment in oil related exploration and development was $538 million and $500 million was invested in natural gas, mainly natural gas resource plays, during 2012 compared with $591 million for oil and $359 million for natural gas in 2011.

In addition, $245 million was spent on production optimization and cost reduction initiatives in 2012. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $398 million.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling, were $586 million during 2012 compared to $587 million in 2011.

Oil Sands

During 2012, capital expenditures on Oil Sands projects increased to $658 million compared to $263 million 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 2012.

Atlantic Region

During 2012, $413 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. A drill center was excavated at the South White Rose Extension and a temporary guide base was installed in 2012. In addition, one infill oil well was drilled in the White Rose field during 2012.

Asia Pacific Region

Total capital expenditures of $747 million were invested in the Asia Pacific Region in 2012 primarily for development of the Liwan Gas Project. Five exploration wells were drilled at the Madura Strait in Indonesia during 2012.

Upstream Turnarounds

During 2012, Husky and its partners executed two major maintenance offstations for production facilities in the Atlantic Region. The Husky-operated SeaRose FPSO underwent a planned maintenance dry-docking in Belfast, Northern Ireland. The project was completed safely with zero lost-time incidents and ahead of schedule. Production resumed on August 13, 2012, approximately three weeks ahead of plan. Production from the White Rose field and satellite extensions had returned to expected levels by the end of the third quarter. The Terra Nova FPSO resumed production on December 9, 2012 following a 26-week shutdown. The combined net annual production impact from both FPSO offstations in 2012 was approximately 14,000 bbls/day.

The non-operated Terra Nova facility continues to ramp up more slowly than anticipated following its 2012 turnaround, with Husky's net share of production reduced until operational issues are resolved.

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 Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Infrastructure gross margin	**55**	40	**162**	169
Marketing and other gross margin	**76**	32	**387**	90
Gross margin	**131**	72	**549**	259
Operating and administrative expenses	**13**	7	**70**	60
Depletion, depreciation and amortization	**6**	5	**22**	24
Other expenses	**—**	1	**—**	1
Income taxes	**28**	15	**116**	44
Net earnings	**84**	44	**341**	130
Commodity trading volumes managed *(mboe/day)*	**197.8**	216.6	**180.1**	181.0

Fourth Quarter

Infrastructure and Marketing net earnings in the fourth quarter of 2012 increased by $40 million compared with the same period in 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.

Twelve Months

Infrastructure and Marketing net earnings in 2012 increased by $211 million compared with 2011 due to the same factors impacting the fourth quarter of 2012.

In 2012, Infrastructure and Marketing capital expenditures totalled $54 million compared to $43 million in 2011.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues	**562**	615	**2,191**	2,217
Gross margin(1)	**145**	153	**555**	589
Operating and administration expenses(1)	**41**	36	**153**	149
Depreciation and amortization	**27**	25	**102**	164
Other expenses (income)	**(15)**	26	**(6)**	74
Income taxes	**24**	17	**80**	52
Net earnings	**68**	49	**226**	150
Upgrader throughput *(mbbls/day)* (2)	**81.1**	76.3	**77.4**	69.6
Synthetic crude oil sales *(mbbls/day)*	**63.4**	58.2	**60.4**	55.3
Upgrading differential *($/bbl)*	**24.27**	22.32	**22.34**	27.34
Unit margin *($/bbl)*(1)	**24.86**	28.57	**25.17**	29.18
Unit operating cost *($/bbl)*(3)	**5.50**	5.13	**5.42**	5.87

(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.

Fourth 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 fourth quarter of 2012 were $68 million compared with $49 million in the same period in 2011. The increase was primarily due to higher average upgrading differentials, higher sales volumes and lower other expenses resulting from a decrease in the fair value of the remaining upside interest payment obligations to Natural Resources Canada and the Alberta Department of Energy.

During the fourth quarter of 2012, the upgrading differential averaged $24.27/bbl, an increase of $1.95/bbl or 9% 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 fourth 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 fourth quarter of 2012 was $89.65/bbl compared to $104.44/bbl in the same period of 2011. The overall unit margin decreased to $24.86/bbl in the fourth quarter of 2012 from $28.57/bbl in the same period in 2011 primarily as a result of lower synthetic crude oil prices partially offset by lower feedstock costs.

Twelve Months

Upgrading net earnings in 2012 were $226 million compared to $150 million in 2011 primarily due to lower other expenses resulting from a decrease in the fair value of the remaining upside interest payment obligations and lower depreciation and amortization, due to certain intangible costs which were derecognized in the second quarter of 2011, partially offset by lower upgrading differentials and synthetic crude oil prices.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues	**933**	928	**3,848**	3,877
Gross margin[1]				
Fuel	**36**	40	**153**	153
Refining	**45**	41	**180**	171
Asphalt	**48**	50	**257**	239
Ancillary	**10**	11	**50**	49
	139	142	**640**	612
Operating and administration expenses	**64**	57	**242**	231
Depreciation and amortization	**21**	20	**83**	80
Other expenses	**1**	2	**4**	6
Income taxes	**14**	16	**80**	75
Net earnings	**39**	47	**231**	220
Number of fuel outlets[2]	**511**	548	**531**	547
Refined products sales volume				
Light oil products *(millions of litres/day)*[3]	**9.6**	9.4	**9.5**	9.5
Light oil products per outlet *(thousands of litres/day)*[3]	**18.8**	17.1	**17.8**	17.3
Asphalt products *(mbbls/day)*	**24.1**	20.1	**26.2**	25.3
Refinery throughput				
Prince George refinery *(mbbls/day)*	**11.4**	11.1	**11.1**	10.6
Lloydminster refinery *(mbbls/day)*	**28.3**	29.0	**28.3**	28.1
Ethanol production *(thousands of litres/day)*	**746.4**	751.9	**721.2**	711.3

(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.*

Fourth Quarter

Gross margins on fuel sales were lower in the fourth quarter of 2012 compared with the same period in 2011 due to lower diesel and ethanol margins.

Higher refining gross margins in the fourth quarter of 2012 compared to the same period in 2011 were primarily due to higher diesel prices. Included in refining gross margins in the fourth quarter of 2012 and 2011 are government assistance grants of $4 million and $5 million, respectively.

Asphalt gross margins were lower in the fourth quarter of 2012 compared with the same period in 2011 due to lower market prices for asphalt and drilling fluids.

Operating and administration expenses increased by $7 million in the fourth quarter of 2012 mainly due to increased maintenance activity compared to the same period in 2011.

Twelve Months

Canadian refined products earnings were higher in 2012 compared to 2011 primarily due to stronger market prices, higher throughput and production, sales optimization initiatives, and lower feedstock costs partially offset by higher operating and administration expenses.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gross revenues	**2,412**	2,381	**10,038**	9,752
Gross refining margin	**310**	284	**1,314**	1,299
Operating and administration expenses	**105**	105	**398**	403
Depreciation and amortization	**57**	52	**212**	195
Other expenses	**5**	1	**9**	4
Income taxes	**55**	46	**257**	254
Net earnings	**88**	80	**438**	443
Selected operating data:				
Lima Refinery throughput (mbbls/day)	**155.9**	142.9	**150.0**	144.3
Toledo Refinery throughput (mbbls/day)	**58.1**	64.4	**60.6**	63.9
Refining margin (U.S. $/bbl crude throughput)	**16.24**	14.80	**17.51**	17.60
Refinery inventory (mmbbls)[(1)]	**11.3**	11.8	**11.3**	11.8

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

Fourth Quarter

U.S. Refining and Marketing net earnings increased in the fourth quarter of 2012 compared with the same period in 2011 primarily due to higher Lima Refinery throughput and an increase in realized refining margins as a result of higher market crack spreads partially offset by lower refinery throughput at Toledo resulting from planned turnaround activity in the quarter.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were higher. The estimated FIFO impact was a reduction in net earnings of approximately $27 million in the fourth quarter of 2012 compared to an increase in net earnings of $68 million in the same period in 2011.

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.

In December, the Company agreed to a three-year contract with hourly employees at the Lima Refinery.

Twelve Months

Net earnings were lower in 2012 primarily due to higher depreciation and amortization combined with an estimated FIFO reduction in net earnings of approximately $28 million in 2012 compared to an increase in net earnings of $122 million in 2011.

Downstream Capital Expenditures

In 2012, Downstream capital expenditures totalled $457 million compared with $373 million in 2011. In Canada, capital expenditures were $144 million related to upgrades at the Prince George Refinery, the Upgrader and at retail stations. In the United States, capital expenditures totalled $313 million related to the U.S. refineries.

At the Lima Refinery, $150 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $163 million (Husky's 50% share) primarily for construction of the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

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

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

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

5.3 Corporate

Corporate Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions) income (expense)	**2012**	2011	**2012**	2011
Administration expenses	**(29)**	(48)	**(128)**	(195)
Stock-based compensation	**(33)**	(7)	**(54)**	1
Depreciation and amortization	**(13)**	(13)	**(40)**	(38)
Other income	**19**	5	**3**	—
Foreign exchange gains (losses)	**(1)**	(15)	**14**	10
Interest – net	**(1)**	(22)	**(52)**	(143)
Income taxes	**29**	35	**64**	65
Net loss	**(29)**	(65)	**(193)**	(300)

Fourth Quarter

The Corporate segment reported a loss of $29 million in the fourth quarter of 2012 compared with a loss of $65 million in the same period in 2011. Administration expenses were lower in the fourth 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 $26 million due to a higher share price at the end of the fourth quarter of 2012 compared to the same period in 2011. Interest - net decreased by $21 million compared to the same period in 2011 due to increased amounts of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project.

Twelve Months

In 2012, the Corporate segment reported a loss of $193 million compared with a loss of $300 million in 2011. The decrease in corporate losses was primarily due to the same factors which impacted the fourth quarter.

Foreign Exchange Summary	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions, except where indicated)	**2012**	2011	**2012**	2011
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(4)**	45	**43**	(47)
Gains (losses) on cross currency swaps	**—**	(9)	**2**	7
Gains (losses) on contribution receivable	**15**	(25)	**(7)**	34
Other foreign exchange gains (losses)	**(12)**	(26)	**(24)**	16
Net foreign exchange gains (losses)	**(1)**	(15)	**14**	10
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $1.017**	U.S. $0.963	**U.S. $0.983**	U.S. $1.005
At end of period	**U.S. $1.005**	U.S. $0.983	**U.S. $1.005**	U.S. $0.983

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

Consolidated Income Taxes

Consolidated income taxes increased slightly in the fourth quarter of 2012 to $170 million from $149 million in the same period in 2011 due to higher earnings resulting in an effective tax rate of 26% in the fourth quarter of 2012 compared to 27% during the same period in 2011.

	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2012**	2011	**2012**	2011
Income taxes as reported	**170**	149	**814**	916
Cash taxes paid	**(87)**	(40)	**(575)**	(282)

Cash taxes paid in the fourth quarter of 2012 were $87 million compared with $40 million in the same period in 2011 mainly due to higher earnings in the fourth quarter of 2012 compared with the same period in 2011.

Corporate Capital Expenditures

In 2012, Corporate capital expenditures of $84 million were primarily related to computer hardware and software.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the fourth quarter of 2012, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At December 31, 2012, Husky had total debt of $3,918 million partially offset by cash on hand of $2,025 million for $1,893 million of net debt compared to $2,070 million of net debt as at December 31, 2011. At December 31, 2012, the Company had $3.1 billion in unused long-term committed credit facilities, $280 million in unused short-term uncommitted credit facilities, $3.0 billion in unused capacity under its December 2012 Canadian universal short form base shelf prospectus and U.S. $1.5 billion in unused capacity under its June 2011 U.S universal short form base shelf prospectus. The 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 Dec. 31,		Year ended Dec. 31,	
($ millions, except ratios)	**2012**	2011	**2012**	2011
Cash flow				
Operating activities	**1,297**	1,035	**5,189**	5,092
Financing activities	**(184)**	459	**(162)**	910
Investing activities	**(1,353)**	(1,431)	**(4,830)**	(4,420)
Financial Ratios[(1)]				
Debt to capital employed *(percent)*[(2)]			**17.0**	18.0
Debt to cash flow *(times)*[(3)(4)]			**0.8**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]			**106**	98
Interest coverage ratios on long-term debt only[(3)(6)]				
Earnings			**12.5**	14.5
Cash flow			**24.9**	24.7
Interest coverage on ratios of total debt[(3)(7)]				
Earnings			**12.3**	14.1
Cash flow			**24.6**	23.9

(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

Fourth Quarter

In the fourth quarter of 2012, cash generated from operating activities was $1.3 billion compared with $1.0 billion in the fourth quarter of 2011. The increase was mainly due to higher throughput in Downstream and strong Infrastructure and Marketing earnings, partially offset by lower realized commodity prices in Exploration and Production.

Twelve Months

Cash generated from operating activities was $5.2 billion in 2012 compared with $5.1 billion in 2011. Slightly higher cash flow from operations was mainly due to an increase in change in non-cash working capital, partially offset by higher taxes paid and lower net earnings compared to 2011.

Cash Flow from Financing Activities

Fourth Quarter

In the fourth quarter of 2012, cash flow used in financing activities was $184 million compared to cash flow from financing activities of $459 million in the same period in 2011. Cash flow from financing activities was lower in the fourth quarter of 2012 compared to the same period in 2011 due to higher cash versus stock dividends paid on common shares and the capitalization of interest related to projects in the Asia Pacific Region and the Sunrise Energy Project.

Twelve Months

Cash flow used in financing activities was $162 million for 2012 compared to cash flow from financing activities of $910 million in 2011. 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 2011.

Cash Flow used for Investing Activities

Fourth Quarter

In the fourth quarter of 2012, cash used for investing activities was approximately $1.4 billion compared with $1.4 billion in the same period in 2011. Cash invested in both periods was primarily for capital expenditures.

Twelve Months

Cash used for investing activities was $4.8 billion in 2012 compared with $4.4 billion 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 December 31, 2012, working capital was $2,404 million compared with $2,054 million at December 31, 2011.

At December 31, 2012, Husky had unused short and long-term borrowing credit facilities totalling $3.4 billion. A total of $235 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.

On December 14, 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $1.5 billion and $1.6 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Base Prospectus") with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until January 30, 2015. As of December 31, 2012, the Company had not issued Securities under the Canadian Base Prospectus. This Canadian Base Prospectus replaced the universal short form base shelf prospectus filed in Canada during November 2010 which had remaining unused capacity of $1.4 billion and expired in December 2012. The ability of the Company to raise capital utilizing the Canadian Base Prospectus is dependent on market conditions at the time of sale.

Capital Structure	**December 31, 2012**	
($ millions)	**Outstanding**	**Available[(1)]**
Total long-term debt	**3,918**	**3,380**
Common shares, retained earnings and other reserves	**19,161**	

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

6.3 Contractual Obligations and Commercial Commitments

In the normal course of business, the Company is obligated to make future payments. The following summarizes known non-cancellable contracts and other commercial commitments:

($ millions)	**Within 1 year**	**After 1 year but not more than 5 years**	**More than 5 years**	**Total**
Long-term debt and interest on fixed rate debt	227	2,254	3,125	5,606
Operating leases	130	806	556	1,492
Firm transportation agreements	217	1,037	2,652	3,906
Unconditional purchase obligations[(1)]	3,089	4,449	78	7,616
Lease rentals and exploration work agreements	85	386	571	1,042
Asset retirement obligations [(2)]	107	409	9,812	10,328
Total	3,855	9,341	16,794	29,990

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.*
(2) *Asset retirement obligation (ARO) amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

The following additions in the fourth quarter are included in total non cancellable contracts and other commercial commitments:

- The Company executed an operating lease agreement with Seadrill for the semi-submersible rig, West Mira. The non cancellable minimum future payments are approximately $129.2 million per year commencing 2015 for five years with an option to extend the contract to 2022.
- The Company executed contracts to purchase refined petroleum products in Canada over the next three years totalling approximately $4.5 billion.
- The Company updated its estimates for Asset Retirement Obligations as outlined in Note 9 of the Condensed Interim Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $8.5 billion as at December 31, 2011 to $10.3 billion as at December 31, 2012 due to increased cost estimates and asset growth in the Upstream and Downstream segments.

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and deferred income taxes.

6.4 Off-Balance Sheet Arrangements

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

6.5 Transactions with Related Parties and Major Customers

The Company sells natural gas to, and purchases steam from; the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the year ended December 31, 2012, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $74 million ($108 million in 2011). For the year ended December 31, 2012, the amount of steam purchases by the Company from Meridian totalled $13 million ($19 million in 2011). The Company provides facility services to Meridian which are measured at cost. For the year ended December 31, 2012, the total cost recovery for these services was $19 million ($16 million in 2011).

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 Management, Discussion and Analysis.

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 December 31, 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 December 31, 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

At December 31, 2012, the Company had entered into a cash flow hedge using forward starting interest rate swap arrangements whereby the Company fixed the underlying U.S. 10-year Treasury Bond rate on U.S. $500 million to June 16, 2014, which is the Company's forecasted debt issuance on the same date. The effective portion of these contracts has been recorded at fair value in other assets; there was no ineffective portion at December 31, 2012. The weighted average swap rate for these forward starting swaps is 2.24%.

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

Foreign Currency Risk Management

At December 31, 2012, 82% or $3.2 billion of Husky's outstanding debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, 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 December 31, 2012, Husky's share of this receivable was U.S. $610 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 other comprehensive income as this item relates to a U.S. dollar functional currency foreign operation. At December 31, 2012, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At December 31, 2012, the cost of a Canadian dollar in U.S. currency was $1.005.

8. Critical Accounting Estimates and Key Judgments

Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in the Company's 2011 Annual MD&A, as well as critical areas of judgments have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

During the fourth quarter of 2012, the Company updated its estimates for Asset Retirement Obligations as outlined in Note 9 of the Condensed Interim Consolidated Financial Statements.

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: January 31, 2013	
• common shares	982,417,002
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	28,793,124
• stock options exercisable	10,607,077

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 authorities 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 December 31, 2012 are compared with results for the three months ended December 31, 2011 and the results for the twelve months ended December 31, 2012 are compared with results for the twelve months ended December 31, 2011. Discussions with respect to Husky's financial position as at December 31, 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 twelve months ended December 31, 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 twelve months ended December 31, 2012:

		Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)		**2012**	2011	**2012**	2011
GAAP	Net earnings	**474**	408	**2,022**	2,224
	Foreign exchange	**—**	13	**(16)**	(6)
	Financial instruments	**(12)**	3	**(37)**	6
	Stock-based compensation	**24**	4	**40**	(1)
	Inventory write-downs	**1**	2	**1**	2
	Asset impairment and write-downs	**—**	51	**—**	52
Non-GAAP	Adjusted net earnings	**487**	481	**2,010**	2,277
	Adjusted net earnings – basic	**0.50**	0.50	**2.06**	2.46
	Adjusted net earnings – diluted	**0.50**	0.50	**2.06**	2.44

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 twelve months ended December 31, 2012:

		Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)		**2012**	2011	**2012**	2011
GAAP	Cash flow – operating activities	**1,297**	1,035	**5,189**	5,092
	Settlement of asset retirement obligations	**38**	37	**123**	105
	Income taxes paid	**87**	40	**575**	282
	Interest received	**(10)**	(8)	**(34)**	(12)
	Change in non-cash working capital	**2**	93	**(843)**	(269)
Non-GAAP	Cash flow from operations	**1,414**	1,197	**5,010**	5,198
	Cash flow from operations – basic	**1.44**	1.25	**5.13**	5.63
	Cash flow from operations – diluted	**1.44**	1.24	**5.13**	5.58

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 completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt including 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;
- with respect to the Company's Western Canadian oil and gas resource plays: anticipated timing of results from the completion program at the Company's Slater River project; drilling and tie-in plans at the Company's Duvernay play; and expected timing of production response from chemical injection at the Company's Fosterton ASP facility;
- with respect to the Company's Heavy Oil properties: scheduled first production at the Company's Sandall heavy oil thermal development project; anticipated timing of first commercial production at the Company's Rush Lake project; and 2013 horizontal and CHOPS drilling plans at the Company's heavy oil properties;

- with respect to the Company's Asia Pacific Region: timing of planned first production at the Company's Liwan gas project; planned timing of resumption of pipe laying activity at the Company's Liwan gas project; timing of planned floatover of the platform topsides to the central platform final location at the Company's Liwan gas project; planned timing of first gas from the Company's Madura Strait Block; and seismic surveying plans at the Company's Taiwan exploration block;

- with respect to the Company's Oil Sands properties: scheduled timing of first production from the Company's Sunrise energy project; estimated costs of Phase 1 of the Company's Sunrise energy project; expected timing of completion of the Design Basis Memorandum for the next phase of the Company's Sunrise energy project; and anticipated timing of filing a regulatory application for the bitumen carbonates pilot at the Company's Saleski property;

- with respect to the Company's Atlantic Region: anticipated timing of completion of construction of and commencement of operations by the Company's West Mira rig; expected timing of commencement of drilling for a supporting water injector at North Amethyst; anticipated timing of commencement of development drilling at the Company's White Rose extension project; and anticipated timing of a decision on the preferred development option at the Company's West White Rose satellite field; and

- with respect to the Company's Downstream operating segment: expected timing of operations of the kerosene hydrotreater at the Lima Refinery; expected timing of start up of the Continuous Catalyst Regeneration Reformer Project at the Toledo Refinery; and scheduled timing and duration of major turnarounds at the Lloydminster Refinery, the Lima Refinery and the 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.