MANAGEMENT'S DISCUSSION AND ANALYSIS

April 25, 2012

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1.0 Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Mar. 31**	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30
($ millions, except where indicated)	**2012**	2011	2011	2011	2011	2010	2010	2010
Production *(mboe/day)*	**319.9**	318.9	309.1	311.6	310.4	280.5	288.7	283.9
Gross revenues[(1)]	**5,984**	5,894	6,073	6,043	5,072	4,294	4,124	4,539
Net earnings	**591**	408	521	669	626	139	261	179
Per share – Basic	**0.61**	0.42	0.55	0.73	0.70	0.16	0.31	0.21
Per share – Diluted	**0.60**	0.42	0.53	0.71	0.70	0.16	0.30	0.19
Cash flow from operations[(2)]	**1,172**	1,197	1,326	1,511	1,164	685	794	739
Per share – Basic	**1.21**	1.25	1.40	1.68	1.31	0.80	0.93	0.87
Per share – Diluted	**1.20**	1.24	1.39	1.67	1.30	0.80	0.93	0.87

[(1)] *Gross revenues have been recast to reflect a change in reclassification of intersegment sales eliminations and a change in presentation for trading activities. Refer to Section 9.0.*
[(2)] *Cash flow from operations is a non-GAAP measure. Refer to Section 11.0 for a reconciliation to the GAAP measure.*

Performance

- Production in the quarter increased by 9.5 mboe/day to 319.9 mboe/day compared with the first quarter of 2011 as a result of increased crude oil production in Western Canada and Tucker and new crude oil production at the West White Rose pilot project, partially offset by lower production at the maturing White Rose fields that were part of the initial development.
- Excluding the $143 million after-tax gain on the sale of non core assets in the first quarter of 2011, net earnings in the first quarter of 2012 increased by 22% when compared to the first quarter of 2011 due to:
  - Higher crude oil production and higher average realized crude oil prices; and
  - Increased volumes at the Upgrader;
  - Partially offset by lower upgrading differentials and U.S. Refining margins.
- Cash flow from operations in the quarter were comparable to the first quarter of 2011, after a significant increase in cash taxes.

Key Projects

- Sunrise Energy Project Phase 1 – the planned 49 horizontal well pairs have been drilled and detailed engineering and construction activities are progressing.
- Liwan Gas Project – installed subsea trees and executed upper completions on initial production wells in the Liwan 3-1 field and successfully flow tested gas in commercial quantities. Shallow water platform jacket construction is more than 75% complete and on target for scheduled offshore installation in the third quarter of 2012.
- Madura Strait Original Gas-in-Place ("OGIP") and front end engineering design ("FEED") studies completed for the MDA and MBH fields joint development. Tender information received for the BD field development.
- Pikes Peak South 8,000 bbls/day and Paradise Hill 3,000 bbls/day heavy oil thermal development are progressing as planned with first oil expected in the third quarter of 2012.
- Western Canada oil and liquids-rich gas resource play drilling progressing with 36 wells drilled during the quarter. In the Northwest Territories, successfully drilled, cored and cased two vertical pilot wells to assess the Canol shales.

Financial

- On March 22, 2012, the Company issued U.S. $500 million of 3.95% senior unsecured notes due April 15, 2022 redeemable at the option of the Company.
- Dividends on common shares of $290 million for the fourth quarter of 2011 were declared during the first quarter of 2012 of which $88 million and $202 million were paid in cash and common shares, respectively.

2.0 Business Environment

Average Benchmarks *(three months ended)*		**Mar. 31 2012**	Dec. 31 2011	Sept. 30 2011	Jun. 30 2011	Mar. 31 2011
WTI crude oil(1)	*(U.S. $/bbl)*	**102.93**	94.06	89.76	102.56	94.10
Brent crude oil(2)	*(U.S. $/bbl)*	**118.49**	109.31	113.46	117.36	104.97
Canadian light crude 0.3% sulphur	*($/bbl)*	**92.70**	97.70	92.06	102.64	88.45
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**69.95**	76.44	62.08	71.82	59.54
NYMEX natural gas(3)	*(U.S. $/mmbtu)*	**2.74**	3.55	4.19	4.31	4.11
NIT natural gas	*($/GJ)*	**2.39**	3.27	3.53	3.55	3.58
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.99**	10.73	18.12	17.89	23.11
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**26.31**	22.05	33.72	25.32	19.34
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**19.35**	19.06	33.43	28.90	16.58
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.999**	0.977	1.021	1.034	1.014
Canadian $ Equivalents						
WTI crude oil(4)	*($/bbl)*	**103.03**	96.27	87.91	99.19	92.80
Brent crude oil(4)	*($/bbl)*	**118.61**	111.88	111.13	113.50	103.52
WTI/Lloyd crude blend differential(4)	*($/bbl)*	**22.01**	10.98	17.75	17.30	22.79
NYMEX natural gas(4)	*($/mmbtu)*	**2.74**	3.63	4.10	4.17	4.05

(1) *Prices quoted are near-month contract prices for settlement during the next month.*
(2) *Dated Brent prices are dated less than 15 days prior to loading for delivery.*
(3) *Prices quoted are average settlement prices for deliveries during the period.*
(4) *Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.*

Oil and Gas Prices

The price Husky receives for production from Western Canada is primarily driven by the price of West Texas Intermediate ("WTI"), adjusted to Western Canada, while the Company's production in the Atlantic and Asia Pacific regions is referenced to the price of Brent crude oil ("Brent"). The price of WTI averaged U.S. $102.93/bbl in the first quarter of 2012 compared with U.S. $94.10/bbl in the first quarter of 2011. The price of Brent averaged U.S. $118.49/bbl in the first quarter of 2012 compared with U.S. $104.97/bbl in the first quarter of 2011.

Canadian crude oil prices in the first quarter of 2012 benefited from the weakening of the Canadian dollar against the U.S. dollar as compared to the same period in 2011. In the first quarter of 2012, the price of WTI in U.S. dollars increased 9% compared to an increase of 11% in Canadian dollars when compared to the same period in 2011.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the first quarter of 2012, 48% of Husky's crude oil production was heavy oil or bitumen compared with 46% in the first quarter of 2011. The light/heavy crude oil differential averaged U.S. $21.99/bbl or 21% of WTI in the first quarter of 2012 compared with U.S. $23.11/bbl or 25% of WTI in the first quarter of 2011.

During the first quarter of 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.74/mmbtu compared with U.S. $4.11/mmbtu in the first quarter of 2011.

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.

During the first quarter of 2012, the Canadian dollar averaged U.S. $0.999, weakening by 1% compared with U.S. $1.014 during the first quarter of 2011.

Refining Crack Spreads

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

During the first quarter of 2012, the Chicago 3:2:1 crack spread averaged U.S. $19.35/bbl compared with U.S. $16.58/bbl in the first quarter of 2011. During the first quarter of 2012, the New York Harbor 3:2:1 crack spread averaged U.S. $26.31/bbl compared with U.S. $19.34/bbl in the first quarter of 2011.

Husky's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and by the time lag between the purchase and delivery of crude oil, 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 first quarter of 2012. The table below shows what the effect would have been on the financial results for the first quarter of 2012 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the first quarter of 2012. Each separate item in the sensitivity analysis shows the 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 greater magnitudes of change.

Sensitivity Analysis	**2012 First 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)	**102.93**	*U.S. $1.00/bbl*	**70**	**0.07**	**52**	**0.05**
NYMEX benchmark natural gas price(5)	**2.74**	*U.S. $0.20/mmbtu*	**27**	**0.03**	**20**	**0.02**
WTI/Lloyd crude blend differential(6)	**21.99**	*U.S. $1.00/bbl*	**(8)**	**(0.01)**	**(7)**	**(0.01)**
Canadian light oil margins	**0.041**	*Cdn $0.005/litre*	**15**	**0.02**	**11**	**0.01**
Asphalt margins	**7.63**	*Cdn $1.00/bbl*	**7**	**0.01**	**5**	**0.01**
U.S. Refining 3:2:1 crack spread	**26.31**	*U.S. $1.00/bbl*	**51**	**0.05**	**32**	**0.03**
Exchange rate (U.S. $ per Cdn $)(3)(7)	**0.999**	*U.S. $0.01*	**(51)**	**(0.05)**	**(38)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 965.8 million common shares outstanding as of March 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.*

3.0 Strategic Plan

Husky's focused integration strategy is to maintain production in its foundation of Western Canada and Heavy Oil and reposition these areas to resource play and thermal development, while advancing its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands. The Company strategically operates and maintains Downstream assets which provide support and value to its Upstream heavy oil and bitumen assets.

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

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation and blending of crude oil and natural gas and storage of crude oil, diluents and natural gas (Infrastructure and Marketing). The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore Greenland, offshore China and offshore Indonesia.

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

4.0 Key Growth Highlights

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

4.1 Upstream

Western Canada (excluding Heavy Oil and Oil Sands)

Liquids-Rich Gas Resource Plays

At Ansell, a liquids-rich resource play in west central Alberta, nine wells were drilled during the first quarter of 2012, including one vertical Cardium well, three horizontal Cardium wells, two Wilrich horizontal wells and three multi-zone vertical wells. Twenty-two Cardium vertical wells, two horizontal Cardium wells, one Wilrich horizontal well and six multi-zone vertical wells were completed during the quarter.

Two horizontal wells were drilled to evaluate the Duvernay liquids-rich gas play at Kaybob. The completion of the horizontal well drilled in late 2011 was executed with test results meeting expectations. The well is anticipated to be placed on production during the second quarter of this year. Two further well completions are scheduled for late 2012.

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

Oil Resource Plays

Across the portfolio, 24 horizontal wells and two vertical pilot wells were drilled during the first quarter of 2012. At the Oungre Bakken project in southeast Saskatchewan, four horizontal wells were drilled during the first quarter of 2012. Two wells were completed and are undergoing post fracture clean up.

In southwestern Saskatchewan at the Lower Shaunavon project, three horizontal wells were drilled during the quarter. Two of the wells have been completed and are undergoing post fracture clean up.

At the southwestern Saskatchewan Viking project, eight horizontal wells were drilled in the quarter. At the Redwater Viking project, five horizontal wells were drilled with three wells completed and undergoing post fracture clean up.

In the northern Cardium oil resource trend, three horizontal wells were drilled at Wapiti. Five wells were completed at Wapiti and four wells were completed at Kakwa and are undergoing post fracture clean up.

In the first quarter of 2012, one horizontal Rainbow Muskwa shale oil resource well was drilled and drilling operations commenced on a two-well pad which will continue through spring break-up. The production testing on the first 2011 horizontal Rainbow Muskwa completion has concluded with test results in line with expectations. The well is currently undergoing pressure build up prior to being placed on production.

In the Northwest Territories, two vertical pilot wells were successfully drilled, cored and cased on the exploration licenses acquired in 2011. These wells will provide information to assess the reservoir characteristics and resource scope of the Canol shales. The 220 square kilometre, three-dimensional ("3-D") seismic program was completed during the second quarter of 2012.

Heavy Oil

Construction of the 8,000 bbls/day Pikes Peak South thermal project is progressing within original cost estimates and was approximately 96% complete at the end of the first quarter. In addition, construction continued on the 3,000 bbls/day Paradise Hill development, which will utilize existing Bolney infrastructure. First oil from each of these two projects is expected to commence on schedule during the third quarter of 2012.

The design of a commercial project is underway at Rush Lake based on 2011 production from a single well pair pilot. The initial planning process is ongoing for three additional commercial thermal projects which are in the early stages of reservoir evaluation and concept selection.

Drilling of 35 horizontal wells were completed out of a planned 140 to 150 well program for 2012.

Sixty-nine cold heavy oil production with sand ("CHOPS") wells were drilled during the first quarter of 2012, compared to 61 CHOPS wells in the first quarter of 2011.

Four solvent Enhanced Oil Recovery ("EOR") pilots were operational during the first quarter. Commissioning of the carbon dioxide ("CO_2") capture and liquefaction plant at the Lloydminster Ethanol Plant was completed. All CO_2 from the ethanol plant is expected to be used in the ongoing solvent EOR piloting program.

Oil Sands

Sunrise Energy Project

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

Detailed engineering activities for facilities and supporting infrastructure continued and construction activities for field facilities also progressed in the first quarter. Construction of the camp is nearing completion and occupancy is expected in the second quarter of 2012.

Development work continued on the next phase of the project with early engineering work proceeding.

McMullen

During the first quarter of 2012, seven evaluation wells were drilled and 24 slant wells that were drilled during late 2011 were put on production in the cold production development project. At the air injection pilot, three horizontal well producers were drilled to further evaluate this resource.

Saleski

Evaluation continued on the information obtained from the vertical stratigraphic test wells drilled and two-dimensional ("2-D") seismic data obtained in 2011. Two additional water source and disposal test wells were drilled during the first quarter.

Contracts for the Design Basis Memorandum ("DBM") of the Saleski pilot plant and the initial field environmental monitoring for the pilot development were awarded during the first quarter. These activities will support a regulatory application for the pilot development plan.

Asia Pacific Region

Offshore China Exploration, Delineation and Development

The Liwan Gas Project development on Block 29/26 in the South China Sea is progressing according to plan. The first three subsea production trees have been batch installed on wells in the Liwan 3-1 gas field and associated upper completions have been completed. Fabrication of the jacket for the shallow water central platform is more than 75% complete and preparations are underway for the planned installation of the jacket to its final offshore location in the third quarter of this year. Two vessels have been mobilized to resume pipe laying in the shallow water from the central platform to the onshore gas plant. Construction of the onshore gas plant is also progressing on schedule.

In March 2012, Husky and China National Offshore Oil Corporation ("CNOOC") signed the Supplemental Agreement for the development of the Liwan 3-1 gas field. This was the last supporting document to the Overall Development Plan for the Liwan 3-1 gas field that has been submitted for final project approval to the Chinese government.

Negotiations for the sale of the Liuhua 34-2 field gas are ongoing. FEED for the development of the Liuhua 29-1 gas field commenced in February 2012. Project execution is proceeding on schedule towards planned first production from Block 29/26 in late 2013/early 2014.

On Block 63/05 in the Qiongdongnan Basin, Husky and CNOOC have agreed to the termination of their petroleum contract after completion of the first phase of the exploration period. Accordingly, the Company has no further contractual obligation with respect to this block.

Indonesia Exploration and Development
On the Madura Strait Block, tenders have been issued for two drilling rigs to perform a six to nine-well exploration drilling program which is expected to commence in June 2012. On the BD field, tender prequalification information for the supply of a leased floating, production, storage and offloading vessel ("FPSO") has been received with bids expected in the third quarter. In addition, OGIP and FEED studies have been completed for the MDA and MBH fields' joint development. First gas production from the Madura Strait Block is anticipated in 2014.

Atlantic Region

White Rose Extension Projects
In 2012, development drilling will continue at North Amethyst and an infill well will be drilled at the main White Rose field to facilitate increased oil recovery from this reservoir.

First production from the West White Rose pilot program was achieved in September 2011. The supporting water injection well was drilled to total depth during the fourth quarter of 2011 and is expected to be completed in the second quarter of 2012. This two-well pilot program will assist in refining the development plan for the full West White Rose field.

Evaluation continued on the feasibility of a concrete wellhead and drilling platform for development of future resources in the White Rose region including the full development of the West White Rose and South White Rose fields. Pre-FEED and FEED contracts to support this work have been awarded in the second quarter of 2012.

Atlantic Region Exploration
Participation is planned in the drilling of up to two exploration wells offshore Newfoundland and Labrador in 2012.

Infrastructure and Marketing

The construction of a 300,000 barrel tank at the Hardisty terminal is on target to be in service in mid-2012. The tank will facilitate moving volumes to U.S. Petroleum Administration for Defense Districts ("PADD") II and PADD III markets.

4.2 Downstream

Lima, Ohio Refinery
The Lima, Ohio Refinery continues to progress reliability and profitability improvement projects that can be implemented in the short term. Site construction has commenced on a 20 mbbls/day kerosene hydrotreater to increase jet fuel production volume. The kerosene hydrotreater is expected to be operational in the first quarter of 2013.

Toledo, Ohio Refinery
The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is progressing as planned. Overall detailed engineering and procurement is complete and construction activities continued during the first quarter of 2012. All heavy haul transports have been completed and equipment is being installed at the site. A major milestone was completed in February 2012 with the installation of the reactor vessel and regeneration modules. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

5.0 Results of Operations

5.1 Upstream

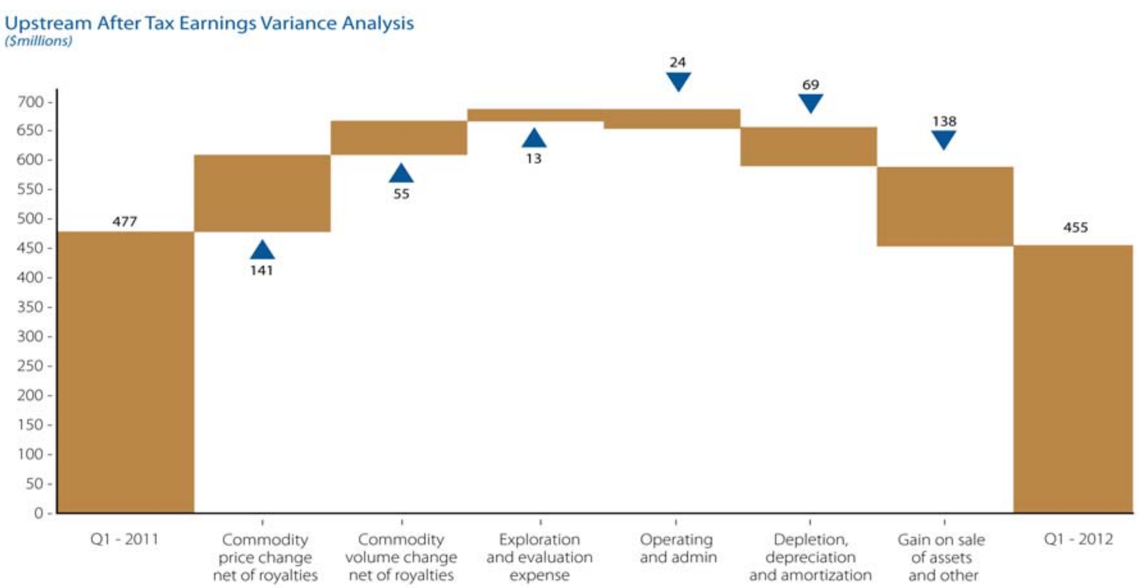
Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	Three months ended March 31 2012	2011
Gross revenues	**1,971**	1,751
Royalties	**(219)**	(258)
Net revenues	**1,752**	1,493
Operating, transportation and administration expenses	**516**	483
Depletion, depreciation and amortization	**529**	436
Exploration and evaluation expense	**75**	93
Other expenses (income)	**18**	(175)
Income taxes	**159**	179
Net earnings	**455**	477

Exploration and Production net earnings in the first quarter of 2012 decreased by $22 million compared with the first quarter of 2011. The decrease includes the impact of an after-tax gain on the sale of non core assets of $143 million included in other income in the first quarter of 2011. Excluding the effect of this gain, Exploration and Production net earnings in the first quarter of 2012, related to operations, increased by approximately $121 million compared to the first quarter of 2011 due to increased crude oil production, higher realized crude oil prices, and decreased royalties offset by lower realized natural gas prices and higher depletion, depreciation, and amortization in the quarter.

Production increased by 9.5 mboe/day in the first quarter of 2012 as compared to the first quarter of 2011 due to increased crude oil production in Western Canada and Tucker and new crude oil production at the West White Rose pilot program, partially offset by lower production at maturing White Rose fields due to natural reservoir declines.

The average realized price in the first quarter of 2012 was $87.11/bbl for crude oil, NGL and bitumen compared with $78.27/bbl during the same period in 2011. Realized natural gas prices averaged $2.64/mcf in the first quarter of 2012 compared with $3.87/mcf in the same period in 2011. Production in the Atlantic and Asia Pacific regions benefited from higher realized prices as the price of Brent increased by approximately 13% while WTI increased by approximately 9% compared with the first quarter of 2011.



Average Sales Prices Realized	Three months ended March 31 **2012**	 2011
Crude oil *($/bbl)*		
Light crude oil & NGL	**111.53**	100.21
Medium crude oil	**78.63**	68.41
Heavy crude oil	**68.93**	61.02
Bitumen	**65.83**	58.11
Total average	**87.11**	78.27
Natural gas average *($/mcf)*	**2.64**	3.87
Total average *($/boe)*	**65.26**	61.03

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

Daily Gross Production	Three months ended March 31 **2012**	 2011
Crude oil *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**30.5**	25.9
Medium crude oil	**24.9**	24.6
Heavy crude oil	**76.2**	73.4
Bitumen	**29.6**	24.2
	161.2	148.1
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**45.3**	49.8
Terra Nova – light crude oil	**6.8**	5.7
	52.1	55.5
China		
Wenchang – light crude oil & NGL	**8.6**	9.6
	221.9	213.2
Natural gas *(mmcf/day)*	**588.3**	583.3
Total *(mboe/day)*	**319.9**	310.4

Crude oil and NGL production in the first quarter of 2012 increased by 8.7 mbbls/day or 4% compared with the same period in 2011. The increase was primarily due to higher production at Tucker and Heavy Oil operations, a full quarter of production from acquisitions that closed mid-February of 2011 and new production at the West White Rose pilot program, partially offset by lower production at maturing White Rose fields due to natural reservoir declines.

Natural gas production in the first quarter of 2012 was comparable with the same period in 2011. Increased production for a full quarter from an acquisition that closed in mid-February of 2011 was offset by natural reservoir declines in mature properties as capital investment has been focused on higher return oil and liquids-rich developments.

2012 Production Guidance

	2012 Guidance	Actual Production: Three months ended March 31 2012	Actual Production: Year ended December 31 2011
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	70 – 75	**91**	88
Medium crude oil	25 – 30	**25**	24
Heavy crude oil & bitumen	100 – 110	**106**	99
	195 – 215	**222**	211
Natural gas *(mmcf/day)*	560 – 610	**588**	607
Total *(mboe/day)*	290 – 315	**320**	312

Guidance for 2012 reflects the impacts of the planned White Rose and Terra Nova offstations.

Royalties

In the first quarter of 2012, royalty rates as a percentage of gross revenue averaged 12% compared with 16% in the same period in 2011. Royalty rates in Western Canada averaged 9% in the first quarter of 2012 compared to 14% in the same period in 2011 and were lower due to a royalty credit adjustment received during the first quarter of 2012. Excluding this adjustment, royalties in Western Canada were comparable to the first quarter of 2011. Royalty rates for the Atlantic Region averaged 14% in the first quarter of 2012 down from 17% in the first quarter of 2011 due to the impact of the North Amethyst field, which is subject to a basic royalty of 1%, compared to White Rose and Terra Nova, which are mature fields that are subject to higher rates. Royalty rates in the Asia Pacific Region averaged 24% in both of the first quarter of 2012 and the first quarter of 2011.

Operating Costs

($ millions)	Three months ended March 31 **2012**	2011
Western Canada	**389**	357
Atlantic Region	**55**	38
Asia Pacific	**6**	5
Total	**450**	400
Unit operating costs *($/boe)*	**14.56**	13.40

Total Exploration and Production operating costs in the first quarter of 2012 increased to $450 million from $400 million in the first quarter of 2011. Total unit operating costs in the first quarter of 2012 averaged $14.56/boe compared with $13.40/boe in the first quarter of 2011.

Operating costs in Western Canada averaged $15.37/boe in the first quarter of 2012 compared with $14.93/boe in the same period in 2011. The impact of higher operating costs in 2012 was partially offset by the increase in production volumes. Acquisitions during 2011 resulted in increased production volumes and associated costs for custom processing, trucking, servicing, maintenance and labour. These increases were partially offset by lower fuel costs to produce heavy oil driven by lower natural gas prices. Maturing fields in Western Canada require more extensive infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive gathering systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs associated with the increased infrastructure through cost reduction and efficiency initiatives and maximizing the utilization of the infrastructures in place.

Operating costs in the Atlantic Region averaged $11.63/boe in the first quarter of 2012 compared with $7.67/boe in the first quarter of 2011. The increase was the result of higher costs in preparation for the upcoming White Rose offstation and maintenance costs for the Terra Nova FPSO combined with lower production in the first quarter of 2012 compared with the first quarter of 2011.

Operating costs in the Asia Pacific Region averaged $7.85/bbl in the first quarter of 2012 compared with $6.34/bbl in the same period in 2011. This increase was the result of lower production and higher maintenance, fuel, workover and helicopter costs in the first quarter of 2012 compared with the same period in 2011.

Exploration and Evaluation Expenses

($ millions)	Three months ended March 31 2012	2011
Seismic, geological and geophysical	**32**	15
Expensed drilling	**38**	37
Expensed land	**5**	41
Total	**75**	93

Exploration and evaluation expenses in the first quarter of 2012 were $75 million compared with $93 million in the first quarter of 2011 primarily due to lower expensed land, partially offset by increased seismic, geological and geophysical activity.

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

In the first quarter of 2012, total DD&A averaged $18.18/boe compared with $15.62/boe in the first quarter of 2011. The increased DD&A rate in the first quarter of 2012 as compared to the same period in 2011 was primarily due to new production from West White Rose and the higher capital cost base associated with North Amethyst production.

Exploration and Production Capital Expenditures

In the first quarter of 2012, Upstream Exploration and Production capital expenditures were $1,015 million. Capital expenditures were $669 million (66%) in Western Canada, $134 million (13%) in the Asia Pacific Region, $58 million (6%) in the Atlantic Region and $154 million (15%) in the Oil Sands. Husky's major projects remain on budget and schedule.

Exploration and Production Capital Expenditures[1]	Three months ended March 31 2012	2011
Exploration		
Western Canada	**87**	122
Development		
Western Canada	**577**	404
Oil Sands	**154**	35
Asia Pacific Region	**134**	47
Atlantic Region	**58**	62
	923	548
Acquisitions		
Western Canada	**5**	842
	1,015	1,512

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

Western Canada, Heavy Oil & Oil Sands

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

	Three months ended March 31			
	2012		2011	
***Wells Drilled** (wells)*[(1)]	**Gross**	**Net**	Gross	Net
Exploration				
Oil	**23**	**18**	10	9
Gas	**11**	**10**	9	9
Dry	**–**	**–**	3	3
	34	**28**	22	21
Development				
Oil	**217**	**197**	202	190
Gas	**11**	**8**	31	27
Dry	**1**	**1**	–	–
	229	**206**	233	217
Total	**263**	**234**	255	238

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

The Company drilled 234 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first quarter of 2012 resulting in 215 net oil wells and 18 net natural gas wells in the current period compared with 238 net wells resulting in 199 net oil wells and 36 net natural gas wells in the first quarter of 2011.

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

During the first quarter of 2012, Husky invested $669 million on exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $1,368 million in the first quarter of 2011. Property acquisitions totalling $5 million were completed during the first quarter of 2012 primarily in East Central Alberta, compared with $842 million in the first quarter of 2011. During the quarter, $185 million was invested in oil related exploration and development and $175 million was invested in natural gas related exploration and development compared with $149 million for oil related exploration and development and $67 million for natural gas related exploration and development in the same period in 2011.

In addition, $53 million was spent on production optimization and cost reduction initiatives in the first quarter of 2012. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $93 million.

During the first quarter of 2012, capital expenditures on heavy oil projects, related to thermal projects, CHOPS drilling and horizontal drilling, were $158 million as compared to $161 million in the same period of 2011.

Oil Sands

During the first quarter of 2012, capital expenditures on Oil Sands projects increased to $154 million as compared to $35 million in the same period in 2011 as Phase 1 of the Sunrise Energy Project progressed and activity at the central processing facility and field facilities accelerated. In addition, the Company drilled 29 gross (15 net) stratigraphic test wells at the Sunrise Energy Project during the first quarter of 2012.

Asia Pacific Region

During the first quarter of 2012, total capital expenditures of $134 million were invested in the Asia Pacific Region for development related activities for the Liwan Gas Project. No exploration wells were drilled in the Asia Pacific Region during the first quarter of 2012.

Atlantic Region

During the first quarter of 2012, $58 million was invested in Atlantic Region projects, primarily on the continued development of the White Rose Extension Project including the West White Rose and North Amethyst satellite fields. No exploration wells were drilled in the Atlantic Region during the first quarter of 2012.

Infrastructure and Marketing

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

Infrastructure and Marketing Earnings Summary *($ millions)*	Three months ended March 31 **2012**	 2011
Gross revenues	**614**	495
Marketing and other	**71**	35
Total revenues	**685**	530
Gross margin	**94**	82
Operating and administrative expenses	**16**	21
Depletion, depreciation and amortization	**5**	6
Other expenses (income)	**(1)**	-
Income taxes	**18**	14
Net earnings	**56**	41
Commodity trading volumes managed *(mboe/day)*	**181.8**	241.5

Infrastructure and Marketing net earnings in the first quarter of 2012 increased by $15 million as compared with the first quarter of 2011 as a result of marketing activities utilizing the Company's access to infrastructure moving crude oil from Canada to the U.S. to take advantage of location differentials as Canadian crude oil differentials widened, partially offset by lower natural gas storage volumes and margins.

In the first quarter of 2012, Infrastructure and Marketing capital expenditures totalled $10 million as compared to $6 million in the same period in 2011.

Upstream Planned Turnarounds

The planned offstation for the SeaRose FPSO will commence as planned in the second quarter of 2012 which will result in production from the White Rose, North Amethyst, and West White Rose fields being shut-in for approximately 125 days. The impact, averaged over the entire year, is forecasted to be approximately 12,000 bbls/day.

A 21-week dockside maintenance for the non-operated Terra Nova FPSO is scheduled to be completed during the second half of 2012. The impact to annual production is estimated to be approximately 4,000 bbls/day. The program anticipates a return to the field and reinstatement of production by the end of 2012.

5.2 Downstream

Upgrader

Upgrader Earnings Summary *($ millions, except where indicated)*	Three months ended March 31 2012	2011
Gross revenues	**581**	368
Gross margin	**134**	99
Operating and administration expenses	**41**	58
Depreciation and amortization	**25**	25
Other expenses	**3**	12
Income taxes	**17**	1
Net earnings	**48**	3
Upgrader throughput *(mbbls/day)* [(1)]	**78.8**	53.2
Synthetic crude oil sales *(mbbls/day)*	**61.1**	41.0
Upgrading differential *($/bbl)*	**20.38**	24.00
Unit margin *($/bbl)*	**23.68**	26.25
Unit operating cost *($/bbl)*[(2)]	**5.54**	12.16

(1) *Throughput includes diluent returned to the field.*
(2) *Based on throughput.*

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 feedstock and the sales price of synthetic crude oil.

Upgrading net earnings in the first quarter of 2012 were $48 million compared with $3 million in the same period in 2011. The increase was primarily due to higher throughput and decreased operating expenses in the first quarter of 2012 as compared to the same period in 2011 due to a minor fire in early 2011. During the first quarter of 2012, the upgrading differential averaged $20.38/bbl, a decrease of $3.62/bbl or 15% compared with the first quarter of 2011. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. While in the past Western Canadian synthetic crude has traded at a premium to WTI, in the first quarter of 2012, synthetic crude traded at a discount to WTI as a result of oversupply and export pipeline constraints in Western Canada. The average price for Husky Synthetic Blend in the first quarter of 2012 was $97.68/bbl compared to $92.64/bbl in the first quarter of 2011. The overall unit margin decreased to $23.68/bbl in the first quarter of 2012 from $26.25/bbl in the same period in 2011 primarily as a result of narrower heavy to light crude oil price differentials. Other expenses in the first quarter of 2011 reflected an increase in the fair value of the remaining upside interest payment obligation to Natural Resources Canada and the Alberta Department of Energy which are based on upgrading differentials.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	Three months ended March 31 **2012**	2011
Gross revenues	**880**	827
Gross margin		
Fuel	**35**	38
Refining	**41**	49
Asphalt	**29**	22
Ancillary	**12**	11
	117	120
Operating and administration expenses	**54**	55
Depreciation and amortization	**20**	18
Interest – net	**1**	1
Income taxes	**11**	12
Net earnings	**31**	34
Number of fuel outlets[(1)]	**549**	550
Refined products sales volume		
Light oil products *(millions of litres/day)*[(2)]	**9.1**	9.4
Light oil products per outlet *(thousands of litres/day)*[(2)]	**16.6**	17.1
Asphalt products *(mbbls/day)*	**20.4**	19.9
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**11.1**	11.0
Lloydminster Refinery *(mbbls/day)*	**27.2**	28.9
Ethanol production *(thousands of litres/day)*	**722.0**	706.4

(1) *Average number of fuel outlets for period indicated.*
(2) *Light oil products have been redefined to include ethanol sales. Prior periods have been recast to reflect this change in definition.*

Gross margins on fuel sales were marginally lower in the first quarter of 2012 compared with the same period in 2011 as a result of lower retail margins offset partially by higher wholesale margins.

Lower refining gross margins in the first quarter of 2012 as compared to the same period in 2011 were primarily due to lower realized prices at the Lloydminster Ethanol Plant and increased cost of grain at the Minnedosa Ethanol Plant. Included in refining gross margins in the first quarter of 2012 and 2011 were government assistance grants of $9 million and $13 million, respectively.

Asphalt gross margins were higher in the first quarter of 2012 compared with the first quarter of 2011 due to higher realized residual and asphalt margins and increased sales volumes partly attributed to strong demand for drilling fluids.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	Three months ended March 31 **2012**	2011
Gross revenues	**2,492**	2,244
Gross refining margin	**259**	329
Operating and administration expenses	**95**	95
Depreciation and amortization	**51**	50
Interest – net	**1**	1
Income taxes (recoveries)	**41**	67
Net earnings	**71**	116
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**139.4**	148.9
Toledo Refinery throughput *(mbbls/day)*	**67.3**	67.9
Refining margin *(U.S. $/bbl crude throughput)*	**14.14**	16.83
Refinery inventory *(mmbbls)*[1]	**10.6**	10.9

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

U.S. Refining and Marketing net earnings decreased in the first quarter of 2012 as compared with the first quarter of 2011 due to the consumption of higher priced feedstock at the Lima Refinery (where approximately half of the feedstock is Brent based) and a catalyst replacement at Lima which resulted in a 10-day diesel hydrotreater outage, partially offset by higher realized market prices for refined products.

The Chicago 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.

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.

Downstream Capital Expenditures

In the first quarter of 2012, Downstream capital expenditures totalled $64 million compared with $47 million in the first quarter of 2011. In Canada, capital expenditures were $21 million related to upgrades at retail stations, the Prince George Refinery and at the Upgrader. In the United States, capital expenditures totalled $43 million related to U.S. refineries. At the Lima Refinery, $22 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $21 million (Husky's 50% share) primarily for construction on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Upgrader began a minor turnaround in mid-April for regular maintenance and catalyst change-out. The Upgrader was shut down during the maintenance program, which is expected to last approximately 20 days. The Company's ethanol plant, which is integrated with the Upgrader, has a planned maintenance outage scheduled for early May.

The Lloydminster Refinery has a major turnaround scheduled in the spring of 2013. The refinery is expected to be shutdown for 21 days during the turnaround for inspections and equipment repair.

The Toledo Refinery is scheduled to have a minor turnaround during the third quarter of 2012. The partial outage is expected to last approximately 21 days.

At the Lima Refinery, a 29-day aromatics turnaround is expected in the fourth quarter of 2012 and the planned outage is not expected to have a material impact on crude throughputs. The Lima Refinery is scheduled to complete a major turnaround in 2014 on 70% of the operating units. The refinery is expected to be shutdown for 45 days during the turnaround. The remaining 30% of the operating units are scheduled to be addressed in a major turnaround currently planned for 2015.

5.3 Corporate

Corporate Earnings Summary *($ millions) income(expense)*	Three months ended March 31 2012	2011
Operating and administration expenses	**(40)**	(18)
Stock-based compensation	**(4)**	(5)
Depreciation and amortization	**(7)**	(7)
Other income (expenses)	**(5)**	2
Foreign exchange gains (losses)	**(1)**	2
Interest – net	**(20)**	(46)
Income taxes	**7**	27
Net loss	**(70)**	(45)

The Corporate segment reported a loss of $70 million in the first quarter of 2012 compared with a loss of $45 million in the same period in 2011. Increases in operating and administration expenses are related to increases in corporate initiatives in the first quarter of 2012 compared with the same period in 2011. Interest – net decreased by $26 million as compared to the first quarter of 2011 due to increased amounts of capitalized interest related to projects in the Asia Pacific Region.

Foreign Exchange Summary *($ millions, except where indicated) gain(loss)*	Three months ended March 31 2012	2011
Gains on translation of U.S. dollar denominated long-term debt	**32**	48
Losses on cross currency swaps	**(6)**	(8)
Losses on contribution receivable	**(18)**	(28)
Other losses	**(9)**	(10)
Foreign exchange gains (losses)	**(1)**	2
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. 0.983**	U.S. $1.005
At end of period	**U.S. 1.001**	U.S. $1.029

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

Consolidated Income Taxes

Consolidated income taxes decreased in the first quarter of 2012 to $239 million from $246 million in the first quarter of 2011 resulting in an effective tax rate of 29% and 28%, respectively.

($ millions)	Three months ended March 31 2012	2011
Income taxes as reported	**239**	246
Cash taxes paid	**199**	21

Cash taxes paid in the first quarter of 2012 were $199 million compared with $21 million in the same period in 2011, due to the change in tax legislation in respect of the taxation of partnerships, of which $16 million related to instalments paid in respect of 2011 net earnings and $183 million related to 2012 earnings.

Corporate Capital Expenditures

In the first quarter of 2012, Corporate capital expenditures of $5 million were primarily related to computer hardware and software.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the first quarter of 2012, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At March 31, 2012, Husky had total debt of $4,346 million partially offset by cash on hand of $2,671 million for $1,675 million of net debt compared to $2,070 million of net debt as at December 31, 2011. At March 31, 2012, the Company had $3.3 billion in unused committed credit facilities, $294 million in unused short-term uncommitted credit facilities, $1.4 billion in unused capacity under the November 2010 universal short form base shelf prospectus filed in Canada, and U.S. $1.5 billion in unused capacity under the June 2011 U.S. base shelf prospectus. The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. Refer to Section 6.2.

Cash Flow Summary *($ millions, except ratios)*	Three months ended March 31	
	2012	2011
Cash flow		
Operating activities	**1,483**	1,283
Financing activities	**477**	77
Investing activities	**(1,126)**	(1,554)
Financial Ratios[1]		
Debt to capital employed *(percent)*[2]	**19.3**	21.2
Debt to cash flow *(times)*[3][4]	**0.8**	1.2
Corporate reinvestment ratio *(percent)*[3][5]	**107**	127
Interest coverage ratios on long-term debt only[3][6]		
Earnings	**14.2**	7.7
Cash flow	**26.4**	14.6
Interest coverage on ratios of total debt[3][7]		
Earnings	**13.8**	7.5
Cash flow	**25.6**	14.2

(1) *Financial ratios constitute non-GAAP measures. Refer to Section 11.0*
(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

In the first quarter of 2012, cash generated from operating activities was $1,483 million compared with $1,283 million in the first quarter of 2011. Higher cash flow from operating activities was primarily due to higher upstream production and higher crude oil prices in Upstream.

Cash Flow from Financing Activities

In the first quarter of 2012, cash generated from financing activities was $477 million compared to $77 million in the same period in 2011. The increase in cash provided by financing activities was due to the issue of senior unsecured notes during the current quarter.

Cash Flow used for Investing Activities

In the first quarter of 2012, cash used in investing activities was $1,126 million compared with $1,554 million in the same period in 2011. Cash invested in both periods was primarily for capital expenditures and acquisitions.

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 March 31, 2012, working capital was $2,500 million compared with $2,054 million at December 31, 2011.

At March 31, 2012, Husky had unused short and long-term borrowing credit facilities totalling $3.6 billion. A total of $221 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

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

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

	March 31, 2012	
Capital Structure *($ millions)*	**Outstanding**	**Available**[(1)]
Total short-term and long-term debt	**4,346**	**3,594**
Common shares, retained earnings and accumulated other comprehensive income	**18,227**	

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

6.3 Contractual Obligations and Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to Husky's 2011 Annual MD&A under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments as at December 31, 2011. At March 31, 2012, Husky did not have any additional material contractual obligations and commercial commitments. There were no material changes to commitments noted during the first quarter of 2012.

6.4 Off-Balance Sheet Arrangements

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

6.5 Transactions with Related Parties and Major Customers

The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales are related party transactions and have been measured at fair value. For the three months ended March 31, 2012, the total value of natural gas sales to the Meridian and other cogeneration facilities was $12 million. For the three months ended March 31, 2012, the total value of obligated steam purchases from the Meridian and other cogeneration facilities was $4 million.

7.0 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 ("AIF") filed on the Canadian Securities Administrator's website, *www.sedar.com*, the Securities and Exchange Commission's website, *www.sec.gov*, or Husky's website *www.huskyenergy.com*.

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 political, environmental, financial, liquidity and contract and credit risk has not changed since December 31, 2011, as discussed in the Company's 2011 Annual MD&A. The following provides an update on the Company's commodity, interest rate and foreign exchange risk management.

Commodity Price Risk Management

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

At March 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 also was 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 March 31, 2012, the Company was party to third party crude oil purchase and sale derivative contracts, which have been designated as a fair value hedge. The crude oil inventory held in storage is recorded at fair value.

The Company had the following risk management contracts and related inventory recorded at fair value on the consolidated balance sheets at March 31, 2012:

	March 31, 2012		
Risk Management *($ millions)*	Asset	Liability	Net
Commodity Price			
Natural gas contracts	5	(5)	–
Natural gas storage contracts	52	(22)	30
Natural gas storage inventory	95	–	95
Crude oil contracts[(1)]	2	–	2
Crude oil inventory[(1)]	17	–	17
Crude oil contracts	4	–	4
Crude oil inventory	176	–	176
	351	(27)	324
Foreign Currency			
Cross currency swaps[(2)]	–	(100)	(100)
Foreign currency forwards	–	–	–
	351	(127)	224

(1) *Designated as a fair value hedge with fair value recognized in accounts receivable and inventories on the consolidated balance sheets.*
(2) *Designated as a cash flow hedge with fair value recognized in accounts payable and accrued liabilities on the consolidated balance sheets. At March 31, 2012, the balance in other reserves related to derivatives designated as a cash flow hedge was $2 million, net of tax of less than $1 million.*

The unrealized gains (losses) recognized on risk management positions for the three months ended March 31, 2012 are set out below:

	Three months ended March 31, 2012				
Earnings Impact *($ millions)*	Marketing and other	Other – net	Purchases of crude oil and products	Net foreign exchange gains (losses)	OCI
Commodity Price					
Natural gas contracts	–	–	–	–	–
Natural gas storage contracts	**6**	–	–	–	–
Natural gas storage inventory	**(2)**	–	–	–	–
Crude oil contracts[(1)]	–	–	**2**	–	–
Crude oil inventory[(1)]	–	–	–	–	–
Crude oil contracts	**8**	–	–	–	–
Crude oil inventory	**26**	–	–	–	–
	38	–	**2**	–	–
Foreign Currency					
Cross currency swaps, net of tax[(2)]	–	**(1)**	–	**(6)**	–
Foreign currency forwards[(3)]	–	**(1)**	–	**2**	–
	38	**(2)**	**2**	**(4)**	–

(1) Designated as a fair value hedge with fair value changes recognized in purchases of crude oil and products on the consolidated statements of income.

(2) Designated as a cash flow hedge with foreign exchange on the translation of the swaps recognized in net foreign exchange gains (losses) on the consolidated statements of income and the effective portion of unrealized gains and losses related to measuring the contract at fair value recognized in other comprehensive income ("OCI"). If a portion of the cash flow hedge was ineffective during the period, the ineffective portion is transferred from OCI to other - net.

(3) Unrealized gains or losses from short-dated foreign currency forwards are included in other - net, while realized gains or losses are included in net foreign exchange gains (losses).

Interest Rate Risk Management

During 2011, the Company discontinued its fair value hedge designation with respect to the remaining interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates. These interest rate swap arrangements were sold and derecognized during 2011. Accordingly, the accrued gains on these interest rate swaps and the previous interest rate swap terminations are being amortized over the remaining life of the underlying long-term debt to which the hedging relationships were originally designated. The amortization period is two to five years.

At March 31, 2012, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps was $87 million. The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $5 million for the three months ended March 31, 2012.

Foreign Currency Risk Management

At March 31, 2012, 84% or $3.6 billion of Husky's outstanding debt was denominated in U.S. dollars.

As at March 31, 2012, the Company had outstanding cross currency swaps instruments which were designated as a cash flow hedge. The percentage of the Company's debt exposed to the Canadian/U.S. exchange rate decreases to 76% when the cross currency swaps are considered.

As at March 31, 2012, the Company had designated U.S. $2.0 billion of its U.S. denominated debt, $700 million of which was designated in the first quarter of 2012, including the U.S. $500 million of the 3.95% senior unsecured notes issued on March 22, 2012, as a hedge of the Company's net investments in its U.S. refining operations. In the three months ended March 31, 2012, the unrealized gain arising from the translation of the debt was $21 million, net of tax of $3 million, which was recorded in OCI.

Including cross currency swaps and the debt that has been designated as a hedge of a net investment, 19% 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 March 31, 2012, Husky's share of this receivable was U.S. $1.1 billion including accrued interest. The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At March 31, 2012, Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

At March 31, 2012, the cost of a U.S. dollar in Canadian currency was $1.0009.

8.0 Critical Accounting Estimates

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

9.0 Changes in Accounting Policy, Presentation and Recent Accounting Standards

Changes in Accounting Policy and Presentation

The following changes in accounting policy and presentation were implemented in the first quarter of 2012.

Presentation of Items of Other Comprehensive Income ("OCI")

In June 2011, the International Accounting Standards Board ("IASB") issued IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and require the Company to group items within OCI based on whether the items may be subsequently reclassified to net earnings. The Company retrospectively adopted the amendments on January 1, 2012. The adoption of the amendments to this standard did not have a material impact on the Company's financial statements; the Company has grouped the items within OCI based on whether the items may be subsequently reclassified to net earnings on the condensed interim consolidated statements of income.

Presentation of Trading Activities

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 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.

Prior periods have been reclassified to reflect this change in presentation. The impact of this change on net earnings is summarized approximately as follows:

($ millions)	Three months ended Mar. 31, 2011	Year ended Dec. 31, 2011
Gross revenues	(625)	(1,497)
Marketing and other	35	90
Purchases of crude oil and products	579	1,399
Other – net	11	8
Net earnings	–	–

Recent Accounting Standards

The IASB issued the following standards and amendments which are not yet effective for the Company and discussed in further detail in Note 3 to the Consolidated Financial Statements for the fiscal year ended December 31, 2011. The IASB did not issue any standards, interpretations or amendments during the first quarter of 2012.

- IFRS 10, "Consolidated Financial Statements" requires retrospective application and will be adopted by the Company on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's consolidated financial statements.
- IFRS 11, "Joint Arrangements," requires retrospective application and will be adopted by the Company on January 1, 2013. The extent of the impact of adoption of IFRS 11 has not yet been determined.
- IFRS 12, "Disclosure of Interest in Other Entities," requires retrospective application and will be adopted by the Company on January 1, 2013 and is expected to increase the current level of disclosure related to the Company's interests in other entities upon adoption.

- IFRS 13, "Fair Value Measurement," requires prospective application and will be adopted by the Company on January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.
- Amendments to IAS 28, "Investment in Associates and Joint Ventures," require retrospective application and will be adopted by the Company on January 1, 2013. The Company does not expect the amendments to IAS 28 to have a material impact on the Company's consolidated financial statements.
- Amendments to IAS 19, "Employee Benefits," require retrospective application and will be adopted by the Company on January 1, 2013. The adoption of the amended standard is not expected to have a material impact on the Company's consolidated financial statements.
- Amendments to IFRS 7, "Financial Instruments: Disclosures," require retrospective application and will be adopted by the Company on January 1, 2013. The adoption of these amended standards is not expected to have a material impact on the Company's consolidated financial statements.
- Amendments to IAS 32, "Financial Instruments: Presentation," require retrospective application and will be adopted by the Company on January 1, 2014. The adoption of these amended standards is not expected to have a material impact on the Company's consolidated financial statements.
- IFRS 9, "Financial Instruments," requires retrospective application and will be adopted by the Company on January 1, 2015. The adoption of the standard is not expected to have a significant impact on the Company's consolidated financial statements.

10.0 Outstanding Share Data

Authorized:

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

Issued and outstanding: April 20, 2012

• common shares	973,684,387
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	31,883,778
• stock options exercisable	6,915,771

11.0 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 MD&A, the 2011 Consolidated Financial Statements and the 2011 AIF filed with Canadian regulatory agencies and the 2011 Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency, for additional information relating to the Company. These documents are available at www.sedar.com, at www.sec.gov and at www.huskyenergy.com.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended March 31, 2012 are compared with results for the three months ended March 31, 2011. Discussions with respect to Husky's financial position as at March 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 IAS 34.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended March 31, 2012 that has materially affected, or is 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, 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, 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 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. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock –based compensation, gain or loss on sale of assets and other non-cash items.

The following table shows the reconciliation of cash flow from operations to cash flow – operating activities for the three months ended March 31:

		Three months ended March 31	
($ millions)		**2012**	2011
Non-GAAP	Cash flow from operations	**1,172**	1,164
	Settlement of asset retirement obligations	**(33)**	(23)
	Income taxes paid	**(199)**	(21)
	Interest received	**11**	-
	Change in non-cash working capital	**532**	163
GAAP	Cash flow – operating activities	**1,483**	1,283

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

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 aerial 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*
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*
Seismic	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Shares, retained earnings and other reserves*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being competed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

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

12.0 Forward-Looking Statements and Information

Certain statements in this document are forward-looking statements within the meaning of Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended, and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements"). The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely," "are expected to," "will continue," "is anticipated," "is targeting," "estimated," "intend," "plan," "projection," "could," "aim," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

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

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans; and the Company's 2012 production guidance.
- with respect to the Company's Asia Pacific Region: scheduled timing of offshore installations; anticipated timing of a planned installation of a platform jacket at the Company's Liwan Gas Project; timing of anticipated first production from Block 29/26; the timing of commencement of the drilling program at the Madura Strait Block; expected timing of receipt of bids for the supply of a leased FPSO at the Madura Strait Block; and anticipated timing of first production at the Madura Strait Block;
- with respect to the Company's Atlantic Region: planned development drilling at North Amethyst; planned extension projects at the Company's White Rose field for 2012; anticipated timing of completion of, and outcomes of, the pilot program at the Company's West White Rose field; 2012 exploration plans in the Atlantic Region; anticipated timing, duration and impact of a planned offstation at the SeaRose FPSO; and anticipated timing, duration and impact of a planned offstation at the Terra Nova FPSO;
- with respect to the Company's Oil Sands properties: anticipated timing of first production at the Company's Sunrise Energy Project; expected timing of occupancy at the camp for the Company's Sunrise Energy Project; and plans for a regulatory application for a pilot development plan at the Company's Saleski property;

- with respect to the Company's Heavy Oil properties: anticipated timing of first oil at the Company's Pikes Peak South and Paradise Hill projects; 2012 drilling program for the Company's Heavy Oil properties; and anticipated use of CO_2 from the Company's CO_2 capture and liquefaction plant at its Lloydminster Ethanol Plant;

- with respect to the Company's Western Canadian oil and gas resource plays: drilling operations on a two-well pad at Rainbow Muskwa; anticipated timing of well completions and production from new wells at the Company's Kaybob property; and anticipated timing of completion operations at the Company's Sinclair property;

- with respect to the Company's Infrastructure and Marketing activities: anticipated service date of a storage tank under construction by the Company at the Hardisty terminal; and

- with respect to the Company's Downstream operating segment: anticipated timing of operations of a kerosene hydrotreater at the Company's Lima Refinery; anticipated timing and duration of scheduled outages at the Company's Upgrader; anticipated timing and duration of scheduled turnarounds at the Company's Lloydminster Refinery; anticipated timing and duration of scheduled turnarounds at the Company's Toledo Refinery; and anticipated timing, duration and impact of planned turnarounds at the Company's Lima Refinery.

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 AIF 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.