MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") APRIL 26, 2011

Table of Contents

1. Summary of Quarterly Results

Quarterly Summary *(millions of dollars, except per share amounts)*	Three months ended							
	March 31 2011[(1)]	Dec. 31 2010 [(2)]	Sept. 30 2010 [(2)]	June 30 2010 [(2)]	March 31 2010[(1)]	Dec. 31 2009 [(2)]	Sept. 30 2009 [(2)]	June 30 2009 [(2)]
Production *(mboe/day)*	**310.4**	280.5	288.7	283.9	295.9	291.5	276.2	317.2
Gross revenues	**$ 5,860**	$ 4,942	$ 4,641	$ 4,817	$ 4,493	$ 3,856	$ 4,087	$ 4,140
Net earnings	**626**	305	257	266	368	320	338	430
Per share - Basic	**0.70**	0.35	0.30	0.31	0.43	0.38	0.40	0.51
Per share - Diluted	**0.70**	0.35	0.30	0.31	0.41	0.38	0.40	0.51
Cash flow from operations [(3)]	**1,164**	1,037	811	806	854	657	452	833
Per share – Basic	**1.31**	1.21	0.96	0.95	1.00	0.77	0.53	0.98
Per share - Diluted	**1.30**	1.21	0.96	0.95	1.00	0.77	0.53	0.98

(1) *Results are reported in accordance with IFRS.*
(2) *Results are reported in accordance with previous Canadian GAAP.*
(3) *Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.*

Performance

- Production in the quarter increased by 14.5 mboe/day to 310.4 mboe/day compared with the first quarter of 2010 due to production from the North Amethyst field and acquisitions in Western Canada, which includes a major liquids-rich natural gas property in the Rainbow Lake area.
- Cash flow from operations in the quarter increased by 36% to $1,164 million compared to $854 million in the first quarter of 2010.
- Net earnings in the quarter increased 70% compared with the first quarter of 2010 due to:
  - Higher crude oil and natural gas production;
  - Higher average realized crude oil prices partially offset by lower realized natural gas prices and the stronger Canadian dollar relative to the U.S. dollar;
  - Increased realized refining margins and volume in both Canadian and U.S. Downstream; and
  - Pre-tax gain on sales of Upstream interests of $189 million.

Acquisitions and Divestitures

- Completed acquisitions of natural gas and oil properties in Alberta and northeast British Columbia adding production of approximately 24 mboe/day, of which approximately 25% is liquids production.
- Closed sale of 23 square miles of oil sands mining leases on January 14, 2011 resulting in a pre-tax gain of $177 million.

Key Projects

- Sunrise Energy Project Phase I progressing with engineering design for surface facilities and drilling of seven horizontal wells completed.
- Drilled one water injection well and one production well at the North Amethyst satellite field.
- Completed drilling of four development wells at the Liwan 3-1 deep water gas field on Block 29/26 in the South China Sea.

Financial

- Strengthened the Company's financial position by a successful issue of preferred shares, raising a total of $300 million in equity financing.
- Approved amendment to the Company's articles allowing shareholders to accept dividends in cash or common shares. Dividends of $267 million were declared during the first quarter of 2011 of which $77 million and $190 million were accepted in cash and common shares respectively.

2. Business Environment

Average Benchmarks		Three months ended				
		March 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010	March 31 2010
WTI crude oil [1]	*(U.S. $/bbl)*	**94.10**	84.89	76.20	78.03	78.71
Brent crude oil [2]	*(U.S. $/bbl)*	**104.97**	86.27	76.86	78.30	76.24
Canadian light crude 0.3% sulphur	*($/bbl)*	**88.45**	80.48	74.77	75.44	80.31
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**59.54**	60.76	57.29	57.10	65.11
NYMEX natural gas [3]	*(U.S. $/mmbtu)*	**4.11**	3.80	4.38	4.09	5.30
NIT natural gas	*($/GJ)*	**3.58**	3.39	3.52	3.66	5.08
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**23.11**	18.37	15.90	14.34	9.29
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**16.58**	9.13	10.16	11.33	6.23
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**19.34**	11.41	8.62	10.44	8.21
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.014**	0.987	0.962	0.973	0.961
Canadian Equivalents						
WTI crude oil [4]	*($/bbl)*	**92.80**	86.01	79.21	80.20	81.90
Brent crude oil [4]	*($/bbl)*	**103.52**	87.41	79.90	80.47	79.33
WTI/Lloyd crude blend differential [4]	*($/bbl)*	**22.79**	18.61	16.53	14.74	9.67
NYMEX natural gas [4]	*($/mmbtu)*	**4.05**	3.85	4.55	4.20	5.52

(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"), less a discount to Western Canada, while the majority of the Company's production in the Atlantic Region is referenced to the price of Brent. The price of WTI averaged U.S. $94.10/bbl in the first quarter of 2011 compared with U.S. $78.71/bbl in the first quarter of 2010. Relative to WTI, the Canadian light crude benchmark has widened by approximately U.S. $3/bbl and the Lloyd heavy crude oil differential has widened by approximately U.S. $18/bbl in the first quarter of 2011 when compared with the same quarter in 2010. The price of Brent averaged U.S. $104.97/bbl in the first quarter of 2011 compared with U.S. $76.24/bbl in the first quarter of 2010.

Increased U.S. crude oil prices have been partially offset by the strengthening of the Canadian dollar. In the first quarter of 2011, the price of WTI in U.S. dollars increased 20% compared with 13% in Canadian dollars when compared to the first quarter of 2010.

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 2011, 46% of Husky's crude oil production was heavy oil or bitumen compared with 47% in the first quarter of 2010. The light/heavy crude oil differential averaged U.S. $23.11/bbl or 25% of WTI in the first quarter of 2011 compared with $9.29/bbl or 12% of WTI in the first quarter of 2010.

During the first quarter of 2011, the NYMEX near-month contract price of natural gas averaged U.S. $4.11/mmbtu compared with U.S. $5.30/mmbtu in the first quarter of 2010.

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 the first quarter of 2011, the Canadian dollar averaged U.S. $1.014 per Canadian dollar, strengthening by 6% compared with U.S. $0.961 during the first quarter of 2010. The Canadian dollar ended 2010 at U.S. $1.005 and closed at U.S. $1.029 on March 31, 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 2011, the Chicago 3:2:1 crack spread averaged U.S. $16.58/bbl compared with U.S. $6.23/bbl in the first quarter of 2010. During the first quarter of 2011, the New York Harbor 3:2:1 crack spread averaged U.S. $19.34/bbl compared with U.S. $8.21/bbl in the first quarter of 2010.

Husky's realized refining margins are affected by the product configuration of its refineries, 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").

Global Economic and Financial Environment

During the first quarter of 2011, WTI spot prices fluctuated between U.S. $106.19/bbl and U.S. $83.13/bbl, rising above U.S. $108/bbl in the first week of April and averaging U.S. $94.10/bbl. Throughout the first quarter of 2011, Brent traded at a premium to WTI averaging U.S. $104.97/bbl. In its April 12, 2011 Short-term Energy Outlook[1] the Energy Information Administration ("EIA") indicated that it still expects markets for crude oil and liquid fuels to tighten over the next two years. The EIA maintains its expectation that world oil consumption will grow an average of 1.5 mmbbls/day through 2012 and that supply from non-member countries of the Organization of the Petroleum Exporting Countries ("OPEC") will increase marginally and as a result the market will need to rely on inventories and increased supply from OPEC. OPEC spare productive capacity was estimated at 4.2 mmbbls/day at the end of 2010 and is expected to decline to 3.4 mmbbls/day by the end of 2011 and further decline to 2.7 mmbbls/day by the end of 2012. OPEC liquid fuel supply, which is not subject to OPEC's production policy, is expected to add marginally to total OPEC supply through 2012. At its meeting on December 11, 2010, OPEC agreed to maintain its current production policy and is scheduled to meet again on June 2, 2011. The EIA estimates that Organization for Economic Cooperation and Development ("OECD") countries held 2.7 billion barrels of commercial oil inventories at the end of

2010. This represents approximately 57 days of forward cover. The EIA expects OECD oil inventories to decline to approximately 56 days of forward cover in 2011 and to 55 days of forward cover in 2012. The movement toward lower inventory levels underscores potential supply risk as crude oil exports from Libya are disrupted and instability continues in other Middle East and North African countries while world demand for crude oil remains robust.

In the EIA's April 12, 2011 Short-term Energy Outlook, natural gas consumption in U.S. markets is expected to rise marginally through 2011 and 2012. Higher consumption in the industrial and electrical generation sectors is mostly offset by reductions in the residential and commercial sectors. Natural gas production in the U.S. is expected to level off in the near term, increasing by 2.4% in 2011 and 0.8% in 2012. Imports of both pipeline natural gas and liquefied natural gas into the U.S. are expected to decline by 4.3% in 2011 and a further 5.4% in 2012. In its Weekly Natural Gas Storage Report(2) released on April 7, 2011, the EIA reported that natural gas stocks were 0.6% above the five year average and 5.2% below the previous year. The EIA expects continued natural gas price volatility in the near term.

At the onset of the 2011 driving season, April 1 to September 30, total gasoline stocks in the United States were 3.7% below the previous year and marginally above the five year average. Distillate inventories were estimated to be 5.1% higher at the end of the first quarter of 2011 compared with the prior year. The EIA expects a marginal increase in gasoline consumption during the 2011 driving season reflecting improved economic conditions partially offset by higher fuel prices.

There are a number of uncertainties that could result in higher or lower commodity prices. They include decisions made by OPEC regarding their production levels, the rate of global and U.S. economic recovery, the response by governments to various fiscal issues, the effect of China's efforts to address its growth and inflation and the general political stability of certain key strategic areas in the world.

Note:

(1) *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – April 12, 2011 Release.*

(2) *"Weekly Natural Gas Storage Report", April 7, 2011, Energy Information Administration, U.S. Department of Energy.*

Sensitivity Analysis

The following table indicates the relative annual effect of changes in certain key variables on Husky's pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the first quarter of 2011. Each 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	2011 First Quarter Average	Increase	Effect on Annual Pre-tax Cash Flow [6]		Effect on Annual Net Earnings [6]	
			($ millions)	*($/share)* [7]	*($ millions)*	*($/share)* [7]
WTI benchmark crude oil price [1]	$ 94.10	*U.S. $1.00/bbl*	66	0.07	49	0.05
NYMEX benchmark natural gas price [2]	$ 4.11	*U.S. $0.20/mmbtu*	25	0.03	18	0.02
WTI/Lloyd crude blend differential [3]	$ 23.11	*U.S. $1.00/bbl*	(14)	(0.02)	(11)	(0.01)
Canadian light oil margins	$ 0.042	*Cdn $0.005/litre*	15	0.02	11	0.01
Asphalt margins	$ 7.45	*Cdn $1.00/bbl*	7	0.01	5	0.01
New York Harbor 3:2:1 crack spread [4]	$ 19.34	*U.S. $1.00/bbl*	72	0.08	46	0.05
Exchange rate (U.S. $ per Cdn $) [1] [5]	$ 1.014	*U.S. $0.01*	(49)	(0.06)	(37)	(0.04)
Interest rate		*100 basis points*	(14)	(0.02)	(10)	(0.01)

(1) *Does not include gains or losses on inventory.*
(2) *Includes decrease in net earnings related to natural gas consumption.*
(3) *Excludes impact on asphalt operations.*
(4) *Relates to U.S. Refining & Marketing.*
(5) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*
(6) *Excludes mark to market accounting impacts.*
(7) *Based on 890.7 million common shares outstanding as of March 31, 2011.*

3. Strategic Plan

Husky's strategy is to continue to exploit oil and gas assets in Western Canada, while advancing its three major growth pillars in the oil sands, the Atlantic Region and South East Asia. Husky is an integrated company in a specialized sense. The Company is not integrated on a barrel-for-barrel basis and seeks to operate and maintain Midstream and Downstream assets which provide specialized support and value to its Upstream assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

4. Key Growth Highlights

The 2011 capital program was established with focus on projects offering the highest potential for returns and mid to long-term growth. Husky's 2011 capital program builds on the momentum achieved in 2010 with respect to accelerating near-term production growth as well as continuing to advance its three major growth pillars in the oil sands, the Atlantic Region and South East Asia.

Upstream

Atlantic Region

White Rose Extension Projects

Development continues at North Amethyst with one water injection well and one development well drilled during the first quarter of 2011.

In August 2010, the Company received regulatory approval for a two-well pilot project to be drilled from existing infrastructure at the West White Rose field. Two production licences were received in the fourth quarter of 2010. One production well was drilled and cased in 2010 with completion expected in the third quarter of 2011.

Atlantic Region Exploration

Husky plans to participate in a Statoil operated Mizzen appraisal well in the third quarter of 2011. The well will aid in evaluating the 2009 discovery on the same prospect.

An exploration well is planned for the fourth quarter of 2011 to test the Fiddlehead prospect in which Husky holds a 50% working interest.

Offshore Greenland

Husky is continuing its evaluation of 2-dimensional ("2-D") and 3-dimensional ("3-D") seismic acquired in 2008 and 2009. A number of leads and prospects have been identified and are being progressed to drillable locations. Well planning will be initiated in the third quarter of 2011 for potential exploration drilling in 2013.

Heavy Oil

Husky is continuing with its strategy to accelerate thermal development in the Lloydminster area.

Construction of the 8,000 bbls/day South Pikes Peak commercial project was approximately 58% complete at the end of the first quarter of 2011. Production is expected to commence in mid 2012.

Husky commenced its 3,000 bbls/day Paradise Hill development in the first quarter of 2011 which will utilize existing Bolney infrastructure and is planned to become operational by the third quarter of 2012. Construction of a single thermal pilot well pair at Rush Lake continued during the first quarter of 2011 with anticipated first production in the fourth quarter of 2011. Four additional commercial thermal projects are in the early delineation and concept selection phase.

Horizontal well developments progressed through the first quarter of 2011, targeting new geological horizons in existing regions. Thirty-one of the planned 104 wells for 2011 were drilled in the first quarter in Alberta and Saskatchewan.

Husky continued to operate two solvent enhanced oil recovery ("EOR") pilots at Edam and Mervin. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with expected completion in the latter half of 2011. This liquefied CO_2 is to be used in the ongoing piloting program.

A microbial EOR pilot in Wainwright, Alberta continued in the first quarter of 2011 with nine wells continuing to show a substantial response eight months after initial treatments. A second pilot in Devonia Lake has commenced with three cycles of treatments completed with preliminary results showing a 20% increase in oil production.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. Husky commenced SAGD drilling for 12 horizontal production wells as part of the Subsurface Phase I of the project with seven wells drilled during the first quarter of 2011. First production for Phase I is planned for 2014.

Detailed engineering activities for supporting infrastructure continued in the first quarter of 2011 while the Front End Engineering Design ("FEED") valuation work for surface facilities was successfully completed at the end of March. This allows the project to continue purchases of major equipment and prepare for surface facility construction scheduled in the third quarter of 2011.

Husky has also initiated conceptual development engineering for subsequent phases and is anticipating a comprehensive full field development plan to be established by the end of 2011.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by continuing to remediate older wells with innovative new stimulation techniques, drilling new wells and initiating new start up procedures. The results will be evaluated over the next six to twelve months. Three well pairs commenced production in late September 2010, which continue to exceed the performance of well pairs previously drilled.

In addition, Husky completed drilling the final three well pairs of its 16 well pair A Pad development in the first quarter of 2011. Steaming commenced on five well pairs in the first quarter with production expected in the second quarter. The remaining well pairs will commence steaming in the second and third quarters of 2011. One well pair was drilled in the Grand Rapids pilot with production expected in the first quarter of 2012. Several applications to the Energy Resources Conservation Board ("ERCB") have been approved or are proceeding for additional drilling and field development through to 2015. Production at Tucker for the first quarter of 2011 was 6,200 boe/day versus average production of 4,000 boe/day in 2010.

McMullen

Cold production from McMullen averaged 2,850 bbls/day in the first quarter of 2011, up from 2,070 bbls/day in the fourth quarter of 2010. Twelve slant development wells and five evaluation wells were drilled in the first quarter of 2011.

Husky received Alberta Environmental ("AENV") approval for the McMullen air injection pilot in the first quarter of 2011 which was the final regulatory approval required for the project. Drilling of the pilot observation wells commenced with four wells drilled during the first quarter. Facility construction will be proceeding in the second quarter of 2011 with air injection scheduled for the third quarter of 2011.

Saleski

In 2011, Husky drilled 24 vertical stratigraphic test wells and acquired approximately 100 km of 2-D seismic data as part of a continuing program to access resource on Husky owned lands in the Carbonates. In addition, survey work has been completed for the applications for 32 vertical stratigraphic wells and 144 km of 2-D seismic data for the upcoming 2012 winter program.

Western Canada (excluding Heavy Oil and Oil Sands)

Northeastern British Columbia Conventional Exploration

Husky participated in a well in the Grizzly Valley located in the foothills of northeastern British Columbia which has been tested at a rate of 33 mmcf/day. Husky has a 42% working interest in the prospect and tie-in of the well was conducted in January.

Gas Resource Plays

Husky's gas resource play portfolio consists of approximately 800,000 net acres of land associated with several projects located within British Columbia and Alberta. Husky increased its land holdings during the first quarter of 2011 by approximately 29,000 acres. 3-D seismic programs were also completed in the Ansell, Horn River, and West Bivouac (Sierra) areas.

Husky continues to focus its activities on the liquids-rich gas resource plays at Ansell, Kakwa and Kaybob areas. In addition, efforts continue to mitigate risk in its dry gas portfolios at Bivouac, Cypress and Horn River.

In the first quarter of 2011, Husky continued development drilling of its liquids-rich natural gas assets in the Ansell area. Four rigs were active and a total of 20 Cardium formation wells were drilled with an expected liquid yield of over 50 bbls/mmcf. Completion activity continued throughout the quarter on both the Cardium program and on the deeper multi-zone wells that were drilled in 2010. An additional 21 wells are currently planned for the remainder of the year. Offload capacity expansion work proceeded through the first quarter with an expected on-stream date of late third quarter of 2011. The offload capacity expansion will result in an increase to total production capacity at Ansell to 56 mmcf/day and over 2,000 bbls/day of liquids.

In Alberta, two deep multi-zone exploration wells were drilled at Kakwa, both of which will be completed in the third quarter of 2011 and a well was spud in Kaybob to evaluate the Duvernay liquids-rich gas play.

In British Columbia, two Jean Marie development wells were drilled at Bivouac and the first Muskwa horizontal well was drilled in the Horn River Basin. The partner-operated horizontal well drilled in 2010 to evaluate the Montney formation on the Cypress acreage was completed in the first quarter of 2011. The well is planned to be tied-in in the third quarter of 2011.

Oil Resource Plays

Husky continues to evaluate the oil resource play portfolio that consists of approximately 500,000 net acres.

Seventeen Viking wells are now on production in the Dodsland/Elrose area of southwest Saskatchewan. Five wells were drilled in the first quarter of 2011. Two of the five wells were put on production and, together with a well completed in 2010, are producing at a combined rate of 225 bbls/day. Six Viking horizontal wells were drilled at Redwater, Alberta in the first quarter of 2011 with three completed and placed on production at a combined rate of 220 bbls/day. To date, 35 wells have been drilled at Redwater and 19 wells are currently on production. By the end of the year, 11 more wells will be drilled and completed with an additional 23 wells placed on production. The remaining four wells will be put on production in 2012 when gas conservation initiatives are completed.

Production and evaluation of the Lower Shaunavon and Bakken zones continues in southern Saskatchewan. Four horizontal wells were drilled in the Lower Shaunavon zone in the first quarter of 2011 and are awaiting completion. Two additional wells are planned. In the Bakken zone, two wells were drilled in the first quarter. The first well has been completed and swab tested while the second well is awaiting completion.

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") EOR Program is underway with active projects at Warner and Crowsnest in Southern Alberta and Gull Lake, Saskatchewan. Future floods include Fosterton and Bone Creek, Saskatchewan. At Fosterton, the facility design work is nearing completion and long lead equipment orders have been placed. Facility construction is expected to commence in late 2011 with an expected start up in 2013.

South East Asia

Offshore China Exploration, Delineation and Development

Development of the Liwan 3-1 deep water gas field is progressing in accordance with the Heads of Agreement (HOA) signed by Husky Oil China Ltd. and China National Offshore Oil Corporate ("CNOOC") in December last year, in which Husky was confirmed as the operator of the deep water portion of the project and CNOOC as the operator of the shallow water portion of the project.

In the first quarter of 2011, Husky successfully drilled the Liwan 3-1-5, Liwan 3-1-6, Liwan 3-1-7 and Liwan 3-1-8 development wells completing the development well drilling program for the field. Tendering of deep water production equipment and pipelines and installation services has been completed.

CNOOC is similarly progressing with the development of the shallow water portion of the project. Tendering for equipment and installation activity is in progress.

The Overall Development Plan ("ODP") for the Liwan 3-1 project has been prepared and is undergoing final reviews and is expected to be submitted to the Chinese authorities for their review and approval in the second quarter 2011. Official project sanctioning of the Liwan development project is expected in late 2011. First gas production from Liwan 3-1 is planned for late 2013. It is expected the natural gas will be sold under a long-term contract at competitive prices in the Guangdong and Hong Kong markets.

Development of the Liuhua 34-2 field is planned to proceed in parallel with and tied-in to the development of Liwan 3-1. The ODP for the Liuhua 34-2 field is in preparation and planned for submission to the Chinese authorities mid 2011. Production from Liwan 3-1 and Liuhua 34-2 is anticipated to start in late 2013, ramping up through 2014.

Husky is currently drilling the Liuhua 29-1-4 appraisal well at the Liuhua 29-1 field. Production from Liuhua 29-1 is anticipated in late 2014.

On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, processing of new 2-D and 3-D seismic data has been completed and drilling of an exploration well is planned for later in 2011. Husky holds a 100% interest in Block 63/05, for which CNOOC has the right to participate up to 51%.

Indonesia Exploration and Development

Both Husky and CNOOC completed the sale of a 10% equity stake in Husky Oil (Madura) Ltd. to Samudra Energy Ltd. through its affiliate SMS Development Ltd. As a result of the sale, Husky and CNOOC respectively hold a 40% interest in Husky Oil (Madura) Ltd. with the remaining 20% balance held by SMS Development Ltd.

The Indonesian government regulator has approved a gas sales price for the Madura Block and final gas sales agreements are expected to be completed later this year. Tendering of the equipment and services for the BD field development is underway. A delineation well, MDA-4, is planned on the MDA field later this year. First gas production from the Madura Block is expected in 2014.

Husky currently holds a 100% working interest in the North Sumbawa II Exploration Block, comprised of 5,000 square kilometres in the East Java Sea, where interpretation of 1,020 kilometres of new 2-D seismic data has been completed and several leads have been identified. Husky will use this data to define exploration prospects for future drilling, which is currently planned to commence in 2012.

Midstream

Husky is proceeding with construction of a 300,000 barrel storage tank at Hardisty, which will be connected to the Keystone Pipeline. Construction of the new tank is expected to be completed in 2012.

Downstream

Lima, Ohio Refinery

The refinery continues to implement short term reliability and profitability projects. Front End Engineering Design has also been completed on a 20 mbbls/day kerosene hydrotreater which will increase jet fuel production volume and improve quality. The refinery continues to evaluate the economics of a staged repositioning project to increase the amount of lower cost heavy crude oil feedstock.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is continuing as planned and construction formally commenced in August 2010. During the first quarter of 2011, overall detailed engineering and procurement was substantially completed and all major construction contracts were awarded with the exception of the Mechanical, Electrical and Instrumentation (ME&I) Contract. The project progresses with no lost time accidents noted. 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

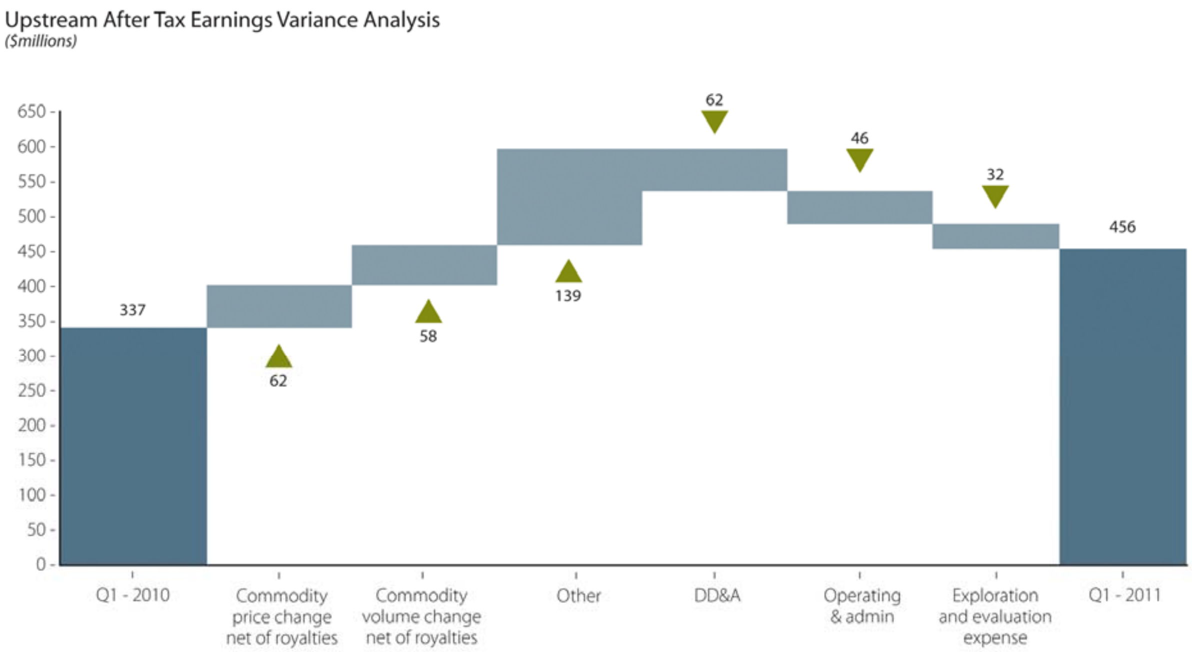
Upstream Net Earnings Summary	Three months ended March 31	
(millions of dollars)	**2011**	2010
Gross revenues	**$ 1,671**	$ 1,538
Royalties	**258**	286
Net revenues	**1,413**	1,252
Operating and administration expenses	**450**	382
Exploration and evaluation expense	**93**	49
Depletion, depreciation and amortization	**432**	346
Other (income) expense	**(190)**	1
Income taxes	**172**	137
Net earnings	**$ 456**	$ 337

Upstream net earnings in the first quarter of 2011 increased by $119 million compared with the first quarter of 2010 primarily as a result of increased crude oil and natural gas production, realized crude oil prices and a pre-tax gain of $177 million recorded on the sale of oil sands mining leases partially offset by lower realized natural gas prices, higher operating expenses, higher depletion and higher exploration and evaluation expense.

Production increased by 14.5 mboe/day due to production from the North Amethyst field which commenced in May 2010. Production from an acquisition in Western Canada is included in the first quarter results from February 4, 2011, the date the acquisition closed. Compared to the prior period, acquisitions in the fourth quarter of 2010 and the first quarter of 2011 added approximately 24 mboe/day of production in Western Canada, partially offset by lower production at White Rose, Terra Nova and Wenchang.

The average realized price in the first quarter of 2011 was $76.78/bbl for crude oil, NGL and bitumen compared with $69.29/bbl during the same period in 2010 with higher realized prices for light oil partially offset by lower realized prices for medium and heavy oil and bitumen reflecting discounts to WTI on Western Canadian production. Realized natural gas prices averaged $3.66/mcf in the first quarter of 2011 compared with $4.81/mcf in the same period in 2010. Production in the Atlantic Region and Wenchang benefited from higher realized prices as the price of Brent increased by 38% compared with the first quarter of 2010, while WTI increased by 20%.

Upstream After Tax Variance Analysis



Pricing

Average Sales Prices Realized		Three months ended March 31	
		2011	2010
Crude oil	*($/bbl)*		
Light crude oil & NGL		$ 99.29	$ 76.72
Medium crude oil		67.83	69.30
Heavy crude oil		58.86	63.31
Bitumen		55.41	61.82
Total average		76.78	69.29
Natural gas average	*($/mcf)*	3.66	4.81
Total average	*($/boe)*	59.82	57.95

The price realized for light crude oil reflects increases in WTI and the significant premium realized for offshore production referenced to Brent prices. In Western Canada non-operated pipeline disruptions resulted in a widening of the differentials for light, medium and heavy crude oil and bitumen. In addition, the increased U.S. dollar crude oil prices were partially offset by the strengthening of the Canadian dollar against the U.S. dollar in 2011 compared to 2010.

Oil and Gas Production

Daily Gross Production		Three months ended March 31	
		2011	2010
Crude oil & NGL	*(mbbls/day)*		
Western Canada			
Light crude oil & NGL		25.9	23.4
Medium crude oil		24.6	25.3
Heavy crude oil		73.4	76.4
Bitumen		24.2	22.6
		148.1	147.7
Atlantic Region			
White Rose - light crude oil		28.4	39.2
North Amethyst - light crude oil		21.4	-
Terra Nova - light crude oil		5.7	10.7
China			
Wenchang - light crude oil & NGL		9.6	11.1
Total crude oil & NGL		213.2	208.6
Natural gas	*(mmcf/day)*	583.3	523.7
Total	*(mboe/day)*	310.4	295.9

Crude Oil and NGL Production

Crude oil, bitumen and NGL production in the first quarter of 2011 increased by 4.6 mbbls/day or 2% compared with the same period in 2010. The increase is primarily due to additional production at North Amethyst, which commenced in May 2010, partially offset by decreased production at White Rose due to natural reservoir decline and at Terra Nova due to operational impacts of H_2S contamination.

Natural Gas Production

Natural gas production increased by 59.6 mmcf/day or 11% in the first quarter of 2011 compared with the first quarter of 2010 due to the acquisitions of properties in Western Canada during the fourth quarter of 2010 and first quarter of 2011, partially offset by reservoir declines in older properties.

2011 Production Guidance			Actual Production	
		Guidance	**Three months ended March 31 2011**	Year ended Dec. 31 2010
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		75 – 80	**90**	81
Medium crude oil		25 – 30	**25**	25
Heavy crude oil & bitumen		95 – 105	**98**	97
		195 – 215	**213**	203
Natural gas	*(mmcf/day)*	560 – 610	**583**	507
Natural gas	*(mboe/day)*	93 – 102	**97**	84
Total barrels of oil equivalent	*(mboe/day)*	290 – 315	**310**	287

Royalties

In the first quarter of 2011, royalty rates averaged 16% as a percentage of gross revenue compared with 19% in 2010. Royalty rates in Western Canada averaged 14%, comparable to 15% in the same period in 2010. Rates for the Atlantic Region averaged 17% in the first quarter of 2011 down from 28% in the first quarter of 2010 due to the North Amethyst field which is subject to a basic royalty of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Rates at North Amethyst will increase and reach the same level as Terra Nova and White Rose after certain project payouts as prescribed in the royalty regulations are met. Royalty rates in Wenchang averaged 24% in the first quarter of 2011, comparable to 23% in the first quarter of 2010.

Operating Costs

	Three months ended March 31	
(millions of dollars)	**2011**	2010
Western Canada	**$ 349**	$ 300
Atlantic Region	**38**	38
International	**6**	4
Total	**$ 393**	$ 342
Unit operating costs *($/boe)*	**$ 14.00**	$ 12.81

Total Upstream operating costs in the first quarter of 2011 increased to $393 million from $342 million reported in the first quarter of 2010 as a result of increased treating, servicing and maintenance costs and acquisitions in the fourth quarter of 2010 and the first quarter of 2011. Total Upstream unit operating costs in the first quarter of 2011 averaged $14.00/boe compared with $12.81/boe in the first quarter of 2010. This increase was driven by higher overall power costs, increased water and emulsion handling requirements in the Lloydminster area, additional perforation activity at Tucker and increased maintenance and well workover activity.

Operating costs in Western Canada averaged $15.72/boe in the first quarter compared with $14.17/boe in the same period in 2010 primarily as a result of increased power, treating and maintenance costs, partially offset by higher production in the first quarter of 2011 compared with the same period in 2010. The increase is also due to additional well workovers and additional perforation activity to stimulate production at Tucker. Maturing fields in Western Canada require increasing amounts for 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 keeping infrastructure fully utilized.

Operating costs in the Atlantic Region averaged $7.65/boe in the first quarter of 2011 compared with $8.24/boe in 2010 due to increased production from North Amethyst in the first quarter of 2011 compared with the first quarter of 2010.

Operating costs at the South China Sea offshore operations averaged $6.34/bbl in the first quarter of 2011 compared with $4.11/bbl in the same period in 2010, as a result of lower production and higher servicing, maintenance and work over costs in the first quarter of 2011 compared with the same period in 2010.

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

In the first quarter of 2011, total DD&A averaged $15.47/boe compared with $13.02/boe in the first quarter of 2010. The increased DD&A rate in the first quarter of 2011 was primarily due to the increased capital cost base associated with the North Amethyst offshore project which commenced production in May 2010.

Exploration and Evaluation Expense

Exploration and Evaluation Expense Summary

	Three months ended March 31	
(millions of dollars)	**2011**	2010
Seismic	**$ 15**	$ 33
Expensed drilling	**37**	4
Other	**41**	15
Total	**$ 93**	$ 52

Exploration and evaluation expenses for the first quarter of 2011 were $93 million, compared with $52 million in the first quarter of 2010 primarily due to increased oil sands exploration activities in Western Canada.

Seismic expenses were $15 million in the first quarter of 2011 compared with $33 million in the first quarter of 2010 due to a shift in Husky's focus to advancing development projects in the first quarter of 2011 where less seismic data is acquired.

Expensed drilling costs were $37 million in the first quarter of 2011, primarily relating to other oil sand pilot test wells, which are not subject to evaluation for economic viability.

Upstream Capital Expenditures

In the first quarter of 2011, Upstream capital expenditures were $1,512 million, including acquisitions of $842 million. Capital expenditures including acquisitions were $1,403 million (93%) in Western Canada, $62 million (4%) in the Atlantic Region and $47 million (3%) in South East Asia. Husky's major projects remain on schedule.

Capital Expenditures Summary [1]	Three months ended March 31	
(millions of dollars)	2011	2010
Exploration		
Western Canada	$ 122	$ 83
Atlantic Region	-	56
International	-	94
	122	233
Development		
Western Canada	439	292
Atlantic Region	62	91
International	47	1
	548	384
Acquisitions		
Western Canada	842	9
	$ 1,512	$ 626

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

The following table discloses the number of gross and net exploration and development wells Husky completed in Western Canada and the oil sands during the periods indicated:

Western Canada and Oil Sands Wells Drilled		Three months ended March 31			
		2011		2010	
		Gross	Net	Gross	Net
Exploration	Oil	10	9	21	19
	Gas	9	9	17	15
	Dry	3	3	7	7
		22	21	45	41
Development	Oil	202	190	205	179
	Gas	31	27	15	9
	Dry	-	-	6	5
		233	217	226	193
Total		255	238	271	234

Western Canada

During the first quarter of 2011, Husky invested $1,403 million on exploration, development and acquisitions throughout the Western Canada Sedimentary Basin compared with $384 million in the first quarter of 2010. Property acquisitions totaling $842 million were completed during the first quarter of 2011, primarily in the Rainbow Lake area of northwestern Alberta, the foothills and deep basin areas of Alberta and in northeastern British Columbia. In addition, $308 million was invested in oil related exploration and development and $124 million was invested in natural gas related exploration and development compared with $203 million for oil related exploration and development and $31 million for natural gas related exploration and development in the first quarter of 2010. The Company drilled 238 net wells in the basin in the first quarter of 2011 resulting in 199 net oil wells and 36 net natural gas wells compared with 234 net wells resulting in 198 net oil wells and 24 net natural gas wells in the first quarter of 2010. Capital expenditures for wells drilled in Western Canada have increased substantially due to the larger numbers of horizontal wells drilled and more multi-stage fracture completions performed compared with 2010.

Husky's major gas resource and conventional high impact exploration program is conducted in various regions along the foothills and northern plains of Alberta and British Columbia and in the deep basin region of Alberta. Of the total expenditures on natural gas related projects during the first quarter of 2011, $57 million in capital expenditures was invested for exploration on gas resource plays and seven gross (five net) wells were drilled all of which resulted in natural gas discoveries.

In addition, $41 million was spent on production optimization and cost reduction initiatives in the first quarter of 2011. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $60 million. During the first quarter of 2011, capital expenditures on oil sands projects were $35 million compared with $19 million in the first quarter of 2010.

The following table discloses Husky's offshore and international drilling activity during the first quarter of 2011:

Offshore and International Drilling Activity			
Canada - Atlantic Region			
North Amethyst G-25-5	WI 68.875%	Production	Development
North Amethyst G-25-6	WI 68.875%	Water Injection	Development
South East Asia - China			
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-6 Block 29/26	WI 49%	Production	Development
Liwan 3-1-7 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development

Atlantic Region Development

During the first quarter of 2011, $62 million was invested in Atlantic Region development projects, primarily one water injection well and one production well in North Amethyst.

Atlantic Region Exploration

No exploration wells were drilled in the Atlantic Region during the first quarter of 2011.

Offshore China and Indonesia

During the first quarter of 2011, $47 million was spent primarily on offshore projects in China, including the drilling of four Liwan 3-1 field development wells on Block 29/26 in the South China Sea.

Upstream Planned Turnarounds

Husky has scheduled a 16-day turnaround for the *SeaRose FPSO* for July 2011 although work is ongoing to further reduce the program's duration. In addition, Husky continues to investigate various options to address the maintenance of the *SeaRose FPSO* propulsion system including an off-station turnaround in 2012.

Husky currently expects its originally scheduled 15-week dockside maintenance for the Terra Nova FPSO to be deferred from July 2011 to a future date. The timing of the turnaround is undergoing finalization by the operator.

5.2 Midstream

Infrastructure and Marketing Net Earnings Summary			Three months ended March 31	
(millions of dollars, except where indicated)			**2011**	2010
Gross revenues			**$ 2,368**	$ 1,826
Gross margin	- pipeline		**$ 35**	$ 32
	- other infrastructure and marketing		**96**	81
			131	113
Operating and administration expenses			**6**	5
Depreciation and amortization			**10**	10
Other expense			**10**	31
Income taxes			**26**	18
Net earnings			**$ 79**	$ 49
Selected operating data:				
Commodity volumes managed		*(mboe/day)*	**1,026**	936
Aggregate pipeline throughput		*(mbbls/day)*	**580**	524

Infrastructure and Marketing net earnings in the first quarter of 2011 were $79 million compared with $49 million in the first quarter of 2010. The increase in net earnings was due to an increase in margins as a result of opportunities to capture trading gains on light and synthetic crude oil moving from Canada to the U.S. as a result of the widening WTI to Brent differential partially offset by lower natural gas storage earnings. Other expenses, which include the fair value impact of the Company's commodity price risk management activities (refer to Section 7.5), decreased by $21 million in the first quarter of 2011 compared with the same period in 2010.

Midstream Capital Expenditures

In the first quarter of 2011, Midstream capital expenditures totalled $6 million compared to $3 million in the same period in 2010.

5.3 Downstream

In the first quarter of 2011, Husky commenced evaluating and reporting its Upgrading activities as part of Downstream operations. As a result, Upgrading was moved from the Midstream segment to the Downstream segment. All prior periods have been restated to conform to these segment definitions.

Upgrading Net Earnings Summary

(millions of dollars, except where indicated)		Three months ended March 31 2011	2010
Gross revenues		$ 368	$ 508
Gross margin		$ 99	$ 90
Operating and administration expenses		58	50
Depreciation and amortization		25	3
Other expense (income)		12	(5)
Income taxes		1	12
Net earnings		$ 3	$ 30
Selected operating data:			
Upgrader throughput [(1)]	*(mbbls/day)*	53.2	82.1
Synthetic crude oil sales	*(mbbls/day)*	41.0	68.6
Upgrading differential	*($/bbl)*	$ 24.00	$ 12.54
Unit margin	*($/bbl)*	$ 20.85	$ 14.62
Unit operating cost [(2)]	*($/bbl)*	$ 12.16	$ 6.77

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

The Upgrading business segment adds 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 2011 were $3 million compared with $30 million in the same period in 2010. The decrease is primarily due to a minor fire at the Lloydminster Upgrader in early February, which resulted in a reduction in the average throughput at the Upgrader to 53.2 mbbls/day, increased repair and depreciation expenses partially offset by higher differentials. The fire was caused when a frozen pipeline burst, releasing fuel into nearby equipment damaging a hydrocracker fractination unit, which supplies product to the coker. No injuries occurred. While damage was not extensive, repairs took place in a congested space under extremely cold weather conditions. Repairs have been made incorporating measures to prevent a similar incident in the future. Normal operations resumed in April 2011.

During the first quarter of 2011, the upgrading differential averaged $24.00/bbl, an increase of $11.46/bbl or 91% compared with the first quarter of 2010. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The overall unit margin increased to $20.85/bbl in the first quarter of 2011 from $14.62/bbl in the same period in 2010 primarily as a result of wider heavy to light crude oil price differentials. There were also increased operating and administration expenses due to repairs associated with the fire in February.

The increase in other expenses is due to the increase in fair value of the remaining upside interest payment obligation to the Minister of Natural Resources of Alberta. The increase in depreciation and amortization in the first quarter of 2011 compared with the first quarter of 2010 is due to significant turnaround costs from the fall of 2010 which were depreciated starting in the fourth quarter of 2010. In the first quarter of 2010 the only turnaround costs being depreciated were from a minor turnaround in 2007, resulting in lower depreciation expense.

Canadian Refined Products Net Earnings Summary

(millions of dollars, except where indicated)		Three months ended March 31 2011	2010
Gross revenues		$ 833	$ 606
Gross margin	- fuel	$ 35	$ 18
	- refining	29	22
	- asphalt	12	10
	- ancillary	11	11
		87	61
Operating and administration expenses		23	25
Depreciation and amortization		18	25
Income taxes		12	3
Net earnings		$ 34	$ 8
Selected operating data:			
Number of fuel outlets (average)		550	470
Light oil sales	*(million litres/day)*	8.4	7.6
Light oil retail sales per outlet	*(thousand litres/day)*	13.2	13.5
Prince George Refinery throughput	*(mbbls/day)*	11.0	9.7
Asphalt sales	*(mbbls/day)*	19.9	18.7
Lloydminster Refinery throughput	*(mbbls/day)*	28.9	27.0
Ethanol production	*(thousand litres/day)*	706.4	720.6

Gross margins on fuel sales were higher in the first quarter of 2011 compared with 2010 as a result of higher retail and wholesale market prices combined with increased volumes due to the purchase of 98 retail stations in 2010 partially offset by lower ethanol production due to an unplanned outage for dryer drum repairs at the Minnedosa plant.

Higher refining gross margins in the first quarter of 2011 were primarily due to higher realized gasoline and diesel prices at the Prince George Refinery and higher production.

Included in refining gross margins in the first quarter of 2011 are $13 million related to government assistance grants compared with $17 million in the first quarter of 2010.

Asphalt gross margins were higher in the first quarter of 2011 compared with 2010 due to higher realized market prices and sales volumes. Asphalt margins were also positively impacted by lower feedstock costs due to widening of the heavy to light crude oil price differential.

U.S. Refining and Marketing Net Earnings Summary		Three months ended March 31	
(millions of dollars, except where indicated)		**2011**	2010
Gross revenues		**$ 2,224**	$ 1,719
Gross refining margin		**$ 328**	$ 97
Operating and administration expenses		**95**	94
Depreciation and amortization		**50**	46
Other expense		**-**	3
Income taxes (recoveries)		**67**	(17)
Net earnings		**$ 116**	$ (29)
Selected operating data:			
Lima Refinery throughput	*(mbbls/day)*	**148.9**	141.7
Toledo Refinery throughput	*(mbbls/day)*	**67.9**	68.0
Realized refining margin	*(U.S. $/bbl crude throughput)*	**$ 16.83**	$ 5.12
Refinery feedstocks and refined products inventory	*(mmbbls)*	**10.9**	11.5

U.S. Refining and Marketing net earnings increased significantly in the first quarter of 2011 compared with the first quarter of 2010 as a result of higher realized refining margins and higher throughput at the Lima Refinery. In addition to increased market crack spreads, feedstock at the Toledo Refinery was approximately 50% heavy crude oil which added to increased margins as differentials between heavy and light crude oil widened in the first quarter of 2011.

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 which was increasing in the first quarter of 2011 while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were lower.

The product slate produced at the Lima and Toledo Refineries contains approximately 10% to 15% of other products which are sold at discounted market prices compared with gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark. The impact of product slates partially offset the factors above.

In addition, the strengthening of the Canadian dollar versus the U.S. dollar in the first quarter of 2011 compared with the same period in 2010 has had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Downstream Capital Expenditures

In the first quarter of 2011, Downstream capital expenditures totalled $47 million compared with $46 million in the first quarter of 2010.

In Canada, capital expenditures were $25 million related to upgrades at the Prince George Refinery and the Upgrader.

In the United States, capital expenditures totalled $22 million. At the Lima Refinery, $13 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $9 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

Husky is scheduled to complete a minor turnaround at the Lloydminster Upgrader in the third quarter of 2011, primarily for inspection and equipment maintenance. During this time, the Upgrader is expected to be at 70% capacity. The next major turnaround is scheduled to commence in the fall of 2013.

The Lloydminster Refinery has a major turnaround scheduled in the spring of 2013. The refinery will be shutdown during the turnaround for inspections and equipment repair.

The Prince George Refinery is scheduled to have two minor turnarounds in the second and third quarters of 2011. The next major turnaround will occur in 2012 during the third and fourth quarter.

The Toledo Refinery will have a minor turnaround in the second quarter of 2011 on the ISO cracker unit and general maintenance. The turnaround is scheduled to last approximately 38 days and during that time throughput is expected to decrease by approximately 17 mboe/day. The next major turnaround is scheduled to occur in 2012.

The Lima Refinery will have a 15-day ISO cracker outage in the fall of 2011 to replace the reactor catalyst. The refinery will be operating at an estimated 90% capacity during that time.

In addition there will be a 15-day aromatics turnaround in the fall of 2012 which will not have a material impact on crude throughputs.

The Lima Refinery will have a major turnaround in 2014 on the Crude, Naptha Hydrotreater, Hydrocracker, Reformer and Diesel Hydrotreater units. The turnaround is scheduled to last approximately 40 days and the refinery will be shutdown during that time. Another major turnaround will occur in 2015 for the remaining 30% of the units including the Fluid Catalytic Cracker, Coker and Gasoline Desulphurization units. The turnaround is scheduled to last approximately 35 days and the refinery will be operating at an estimated 80% capacity.

5.4 Corporate

Corporate Summary *(millions of dollars) income (expense)*	Three months ended March 31 2011	 2010
Intersegment eliminations - net	$ (23)	$ (26)
Administration expense	(17)	(10)
Other income (expense)	1	(1)
Stock-based compensation	(5)	11
Exploration and evaluation expenses	-	(3)
Depreciation and amortization	(7)	(19)
Interest - net	(45)	(39)
Foreign exchange	2	30
Income taxes	32	30
Net loss	$ (62)	$ (27)

The Corporate segment reported a loss of $62 million in the first quarter of 2011 compared with a loss of $27 million in the first quarter of 2010. Stock-based compensation expense increased by $16 million in the first quarter of 2011 compared with the first quarter of 2010 due to higher share prices. The decrease in depreciation and amortization in the first quarter of 2011 compared with the first quarter of 2010 is due to downward revisions in the first quarter of 2010 to the book value of legacy sites that had been deemed inactive. Foreign exchange gains decreased by $28 million to $2 million in the first quarter of 2011 as a result of Husky's risk management efforts to mitigate exposure to foreign exchange volatility.

Intersegment eliminations are net earnings included in inventory that has not been sold to third parties at the end of the period.

Foreign Exchange Summary *(millions of dollars)*	Three months ended March 31 2011	 2010
Gain on translation of U.S. dollar denominated long-term debt	$ (48)	$ (65)
Loss on cross currency swaps	8	11
Loss on contribution receivable	28	39
Other (gains) losses	10	(15)
Foreign exchange (gain) loss	$ (2)	$ (30)
U.S./Canadian dollar exchange rates:		
At beginning of period	U.S. $1.005	U.S. $0.956
At end of period	U.S. $1.029	U.S. $0.985

Included in other foreign exchange (gains) losses is all realized foreign exchange 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.

Corporate Capital Expenditures

In the first quarter of 2011, Corporate capital expenditures of $3 million were primarily for computer hardware and software and construction of a new building in Lloydminster.

Consolidated Income Taxes

During the first quarter of 2011, consolidated income tax expense was $246 million compared with $123 million in the same period in 2010.

Cash taxes paid in the first quarter of 2011 were $21 million compared with $599 million in the first quarter of 2010, of which the entire $21 million relates to instalments paid in respect of 2010 net earnings. Further 2011 cash tax instalments in respect of 2010 earnings are estimated to be approximately $210 million.

6. Liquidity and Capital Resources

In the first quarter of 2011, Husky funded its capital programs, including acquisitions and dividend payments, by cash generated from operating activities, cash on hand and preferred share issuance. At March 31, 2011, Husky had total debt of $4,085 million partially offset by cash on hand of $58 million for $4,027 million of net debt. Husky has no long-term debt maturing until 2012. At March 31, 2011, the Company had $2.7 billion in unused committed credit facilities, $172 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectus filed in Canada of $300 million, and unused capacity under the universal short form base shelf prospectus filed in Canada of $2.4 billion. (Refer to Section 6.4).

Cash Flow Summary

(millions of dollars, except ratios)		Three months ended March 31 2011	2010
Cash flow	- operating activities	$ 1,283	$ 561
	- financing activities	$ 77	$ 474
	- investing activities	$ (1,554)	$ (921)
Financial Ratios [5]			
Debt to capital employed *(percent)*		21.2	21.0
Debt to cash flow *(times)* [1]		1.2	1.4
Corporate reinvestment ratio *(percent)* [1] [2]		127	98
Interest coverage ratios on long-term debt only [1] [3]			
Net earnings		9.3	10.1
Cash flow		16.5	16.1
Interest coverage ratios on total debt [1] [4]			
Net earnings		9.2	9.9
Cash flow		16.3	15.8

(1) *Calculated for the 12 months ended for the dates shown*
(2) *Reinvestment ratio is based on net capital expenditures including corporate acquisitions.*
(3) *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 from 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.*
(4) *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 from operating activities before finance expense on total debt and current incomes taxes divided by finance expense on total debt and capitalized interest. Total debt includes short and long-term debt.*
(5) *2010 comparative results are reported in accordance with previous Canadian GAAP.*

6.1 Operating Activities

In the first quarter of 2011, cash generated from operating activities amounted to $1,283 million compared with $561 million in the first quarter of 2010. Higher cash flows from operating activities is primarily due to higher crude oil and natural gas production, higher crude oil prices in Upstream, higher realized margins in Canadian and U.S. Downstream partially offset by lower natural gas prices.

6.2 Financing Activities

In the first quarter of 2011, cash provided by financing activities was due primarily to the $300 million preferred share issuance during the quarter, offset by cash dividends of $255 million paid on common shares and cash provided by other financing activities of $32 million.

6.3 Investing Activities

In the first quarter of 2011, cash used in investing activities amounted to $1,554 million compared with $921 million in the first quarter of 2010. Cash invested in both periods was primarily for capital expenditures.

6.4 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, the issuance of equity, the issuance of long-term debt and 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, 2011, working capital was $1,051 million compared with $1,181 million at December 31, 2010.

At March 31, 2011, Husky had unused committed long and short-term borrowing credit facilities totalling $3.0 billion. A total of $117 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

Asia Pacific Energy Ltd. 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.

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009 which expired on March 26, 2011. As of March 31, 2011, U.S. $1.5 billion of long-term notes had been issued under this shelf prospectus. On December 21, 2009, Husky filed an additional debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enabled Husky to offer up to $1 billion of medium-term notes in Canada until January 21, 2012. During the 25-month period that the shelf prospectus was effective, medium-term notes could be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of March 31, 2011, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus. (Refer to Note 9 to the Condensed Interim Consolidated Financial Statements).

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 26, 2012. During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement.

On December 7, 2010, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of approximately $293 million pursuant to the universal short form base shelf prospectus. Husky also issued 28.9 million common shares to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total proceeds of approximately $707 million. The Company received total net proceeds of $988 million from this issuance.

On March 18, 2011, Husky issued 12 million Cumulative Rate Reset Preferred Shares, Series 1 ("Series 1 Shares') at a price of $25.00 per share for aggregate gross proceeds of $300 million pursuant to the universal short form base shelf prospectus. Holders of the Series 1 Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.45% annually for the initial period ending March 31, 2016 as declared by Husky. Thereafter, the dividend rate will be reset every five years at a rate equal to the 5-year Government of Canada bond yield plus 1.73%. Holders of Series 1 Shares will have the right, at their option, to convert their shares into Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares"), subject to certain conditions, on March 31, 2016 and on March 31 every five years thereafter. Holders of the Series 2 Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the three-month Government of Canada Treasury Bill yield plus 1.73%.

Capital Structure *(millions of dollars)*	March 31, 2011 Outstanding	Available[(1)]
Total short-term and long-term debt	$ 4,085	$ 3,037
Common shares, preferred shares, retained earnings and other reserves	$ 15,156	

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

6.5 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 2010 annual Management's Discussion and Analysis under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments as at December 31, 2010. At March 31, 2011, 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 2011.

6.6 Off Balance Sheet Arrangements

Husky does not utilize off balance sheet arrangements with unconsolidated entities.

6.7 Transactions with Related Parties

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors as part of the U.S. $750 million 5-year and U.S. $750 million 10-year senior notes issued through the existing base shelf prospectus, which was filed with the U.S. Securities and Exchange Commission in February 2009. The coupon rates offered were 5.90% and 7.25% for the 5 and 10-year tranches respectively. Subsequent to this offering, U.S. $65 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. These transactions were measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At March 31, 2011, the U.S. $1.5 billion senior notes are included in long-term debt on the Company's balance sheet.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

A related party is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at fair value. For the three months ended March 31, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $26 million.

In 2011, the Company and TACLP agreed to sell the Meridian cogeneration facility to a related party. The consideration for Husky's share of the cogeneration facility is $61 million which is equivalent to the carrying value of the facility.

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 2010 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.

7.1 Political Risk

Husky is exposed to risks associated with operating in developing countries, as well as political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

7.2 Environmental Risk

Husky's offshore operations are subject to the risk of blowouts and other catastrophic events, resulting from actions of the Company or its contractors or agents, or those of third parties, that could result in suspension of operations, damage to equipment and harm to personnel, and damage to the natural environment. The consequences of such catastrophic events occurring in deep water operations, in particular, can be more costly and time-consuming to remedy. The remedy may be made more difficult or uncertain by the extreme pressures and cold temperatures encountered in deep water operations, shortages of equipment and specialist personnel required to work in these conditions, or the absence of appropriate and proven means to effectively remedy such consequences. The costs associated with such events could be material and Husky may not maintain sufficient insurance to address such costs. With the exception of Husky's Mizzen prospect, of which Husky is a non-operator, the Company currently does not participate in offshore deep water drilling operations in Canada; however, Husky's development program in China includes deep water drilling.

The Deepwater Horizon oil spill in the Gulf of Mexico has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil operations. Stricter regulation of offshore oil and gas operations has already been implemented in the Gulf of Mexico. Further regulation, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in the Gulf of Mexico. In the event that similar changes in environmental regulation occur with respect to Husky's operations in the Atlantic Region or in the South China Sea, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

The United States Environmental Protection Agency ("EPA") has promulgated the so-called 'Tailoring Rule', which, beginning January 2, 2011, phases in over time restrictions on greenhouse gas emissions from stationary sources, including power plants and petroleum refineries, beginning with the largest emitters, where such sources are required to obtain a new or modified permit based on non-greenhouse gas emissions. Beginning July 11, 2011, the Tailoring Rule will require that any emitters of greater than 100,000 tons per year of greenhouse gases obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. The EPA has also promulgated regulations requiring data collection, beginning January 1, 2010, and reporting, beginning September 30, 2011, of greenhouse gas emissions from stationary sources in the oil and gas industry emitting more than 25,000 tons per year of greenhouse gases in carbon dioxide equivalent. This reporting requirement applies to Husky's U.S. operations. However, these regulations are subject to challenge in Congress and the courts. Congress is considering in the current session several legislation proposals to block or delay the EPA's regulation of greenhouse gas emissions. Among several legal challenges, the State of Texas, the National Association of Manufacturers and other organizations are seeking a stay of the Tailoring Rule and the EPA's other regulations relating to greenhouse gas emissions from stationary sources. It is not possible to predict the ultimate outcome of these challenges. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky and the pending and anticipated challenges could result in the staying of the regulations. Husky's operations may be impacted by future United States greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require Husky's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

7.3 Financial Risk

Husky's financial risks are largely related to commodity prices, refinery crack spreads, exchange rates, interest rates, credit risk, changes in fiscal policy related to royalties and taxes and others. From time to time, Husky uses financial and derivative instruments to manage its exposure to these risks.

7.4 Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual capital expenditure budgets, which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends. The Company's upstream capital programs are funded principally by cash provided from operating activities, common share issuance, long-term debt and available committed and uncommitted credit facilities. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources and during the first quarter of 2011 the Company's articles of association were amended to allow shareholders to accept dividends in cash or common shares. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines.

7.5 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.

At March 31, 2011, the Company had third party physical natural gas purchase and sale contracts and natural gas storage contracts. These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $31 million has been recorded in other expenses in the Consolidated Statements of Income and Comprehensive Income. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At March 31, 2011, the fair value of the inventory was $59 million, resulting in an unrealized gain of $10 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income.

At March 31, 2011, the Company had third party crude oil purchase and sale contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of $1 million has been recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income. The crude oil inventory held in storage is recorded at fair value. At March 31, 2011, the fair value of the inventory was $8 million, resulting in an unrealized loss of $1 million recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income.

The Company also enters into contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at March 31, 2011, a loss related to these contracts of $7 million was recorded in other expenses in the Condensed Interim Consolidated Statements of Income.

The Company enters into certain crude oil purchase and sale contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. 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, 2011, the Company had 1.6 mmbbls of purchase and sale contracts resulting in an unrealized gain of $7 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income. A portion of the crude oil inventory is sold to third parties. This inventory is considered measured at fair value through profit and loss. At March 31, 2011, the fair value of the inventory was $155 million, resulting in an unrealized gain of $4 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income.

7.6 Interest Rate Risk Management

At March 31, 2011, Husky had the following interest rate swaps in place:

- U.S. $200 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for rates ranging from LIBOR + 399 bps to LIBOR + 430 bps until November 15, 2016.
- U.S. $300 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for rates ranging from LIBOR + 255 bps to LIBOR + 275 bps until September 15, 2017.
- U.S. $150 million of long-term debt whereby a fixed interest rate of 5.90% was swapped for rates ranging from LIBOR + 349 bps to LIBOR + 350 bps until June 15, 2014.
- Cdn $300 million of long-term debt whereby a fixed interest rate of 3.75% was swapped for rates ranging from CDOR + 0.80% to CDOR + 0.85% until March 12, 2015.

During the first quarter of 2011, these swaps resulted in an offset to finance expense amounting to $5 million. The amortization of previous interest rate swap terminations resulted in an addition to finance expense of $1 million in the first quarter of 2011.

Cross currency swaps resulted in an addition to finance expense of $2 million, net of tax, in the first three months of 2011.

7.7 Foreign Currency Risk Management

At March 31, 2011, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 6.25% swapped at $1.41 to $211 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $89 million at 5.65% until June 15, 2012.
- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.

At March 31, 2011, the cost of a U.S. dollar in Canadian currency was $0.9718.

Husky's financial results are affected by the exchange rate between the Canadian and U.S. dollar. 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, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At March 31, 2011, 74% or $3 billion of Husky's outstanding debt was denominated in U.S. dollars. The percentage of the Company's debt exposed to the Cdn/U.S. exchange rate decreases to 68% when the cross currency swaps are considered.

As at March 31, 2011, the Company has designated U.S. $987 million of its U.S. debt as a hedge of the Company's net investment in U.S. refining operations, which are considered to have a functional currency of U.S. dollars. During the first quarter of 2011, the unrealized foreign exchange gain arising from the translation of the debt was $19 million, net of tax expense of $3 million, which was recorded in Other Comprehensive Income.

Including cross currency swaps and the debt that has been designated as a hedge of a net investment, 42% of long-term debt is exposed to changes in the Cdn/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, 2011, Husky's share of this receivable was U.S. $1.2 billion including accrued interest. Husky 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 March 31, 2011, Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

7.8 Fair Value of Financial Instruments

The derivative portion of cash flow hedges, fair value hedges, and free standing derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon fair value hierarchy in accordance with the International Accounting Standards Board's ("IASB") IFRS 7. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. All of Husky's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2.

8. Critical Accounting Estimates

Certain of Husky's accounting policies require that it makes appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses.

Depletion Expense

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. Under IFRS, the aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved reserves using the unit of production method.

Withheld Costs

Costs related to exploration and evaluation activities and major development projects are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed or production commences. At that time, costs are either transferred to property, plant and equipment or their value is impaired. Impairment is charged directly to profit or loss under IFRS.

Impairment of Long-Lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cash generating unit exceeds its recoverable amount under IFRS. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The determination of the recoverable amount for impairment purposes under IFRS involves the use of numerous assumptions and judgments including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

Fair Value of Derivative Instruments

Periodically Husky utilizes financial derivatives to manage market risk. IFRS provides for the recognition, measurement and disclosure requirements for financial instruments and hedge accounting. (Refer to Note 13 in the Condensed Interim Consolidated Financial Statements).

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through forward market prices and compared with quotes from financial institutions. The estimation of fair value of forward purchases of U.S. dollars is determined using forward market prices.

Asset Retirement Obligations ("ARO")

Husky has significant obligations to remove tangible assets and restore land after operations cease and Husky retires or relinquishes the asset. The Company's ARO primarily relates to the Upstream business. The retirement of Upstream assets consists primarily of plugging and abandoning well, removing and disposing of surface and subsea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the ARO requires that Husky estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations.

Inherent in the calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, future third-party pricing, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions results in changes to the ARO.

Employee Future Benefits

The determination of the cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The fair value of the plan assets are used for the purposes of calculating the expected return on plan assets.

Legal, Environmental Remediation and Other Contingent Matters

Husky is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. Husky must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Business Combinations

Under the purchase method, the acquiring company includes the fair value of the various assets and liabilities of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. In some circumstances the fair value of an asset is determined by estimating the amount and timing of future cash flows associated with that asset. The actual amounts and timing of cash flow may differ materially and may possibly lead to an impairment charged to earnings.

9. New and Pending Accounting Standards

Financial Instruments

In November 2009, the IASB published IFRS 9 "Financial Instruments" which covers the classification and measurement of financial assets as part of its project to replace IAS 39 "Financial Instruments: Recognition and Measurement." In October 2010, additional requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit or loss and recognize the change in other comprehensive income. IFRS 9 will become effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The implementation of the issued standard is not expected to have a significant impact on the Company's financial position or results.

International Financial Reporting Standards ("IFRS")

Husky has completed its adoption of IFRS for the year beginning on January 1, 2011. As a result, the Company's financial results for the first quarter ended March 31, 2011 and comparative periods are reported under IFRS while selected historical data continues to be reported under previous Canadian GAAP. (Refer to Note 15 of the Condensed Interim Consolidated Financial Statements for the Company's assessment of impacts of the transition to IFRS).

10. Outstanding Share Data

(in thousands)	**April 21 2011**	December 31 2010
Issued and outstanding		
Number of common shares	**897,192**	890,709
Number of stock options	**27,671**	29,541
Number of stock options exercisable	**16,560**	17,325
Number of preferred shares	**12,000**	-

11. Reader Advisories

This Interim Report should be read in conjunction with the Condensed Interim Consolidated Financial Statements and related Notes.

Readers are encouraged to refer to Husky's 2010 MD&A and Note 24 of the 2010 Consolidated Financial Statements and 2010 AIF filed with Canadian regulatory agencies and the 2010 Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency. 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 Interim Report, 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 Interim Report with respect to results for the three months ended March 31, 2011 are compared with results for the three months ended March 31, 2010. Discussions with respect to Husky's financial position as at March 31, 2011 are compared with its financial position at December 31, 2010.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in this Condensed Interim Consolidated Financial Statements 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.

Non-GAAP Measures

Disclosure of Cash Flow from Operations

This Interim Report contains 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 Husky's financial performance. Cash flow from operations is presented in Husky'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, deferred taxes, foreign exchange and other non-cash items. Husky's determination of cash flow from operations, which is a non-GAAP measure, does not have any standardized meaning prescribed by IFRS and therefore is unlikely to be comparable to similar measures presented by other issuers.

The following table shows the reconciliation of cash flow from operations to cash flow - operating activities for the periods noted:

		Three months ended March 31	
(millions of dollars)		**2011**	2010
Non-GAAP	Cash flow from operations	**$ 1,164**	$ 854
	Settlement of asset retirement obligations	**(23)**	(15)
	Income taxes paid	**(21)**	(599)
	Change in non-cash working capital	**163**	321
GAAP	Cash flow - operating activities	**$ 1,283**	$ 561

Disclosure of Adjusted Net Earnings

This interim report may contain the term "adjusted net earnings," which is a non-GAAP measure of net earnings adjusted for certain items that are not an indicator of the Company's on-going financial performance. Husky's determination of adjusted net earnings, which is a non-GAAP measure, does not have any standardized meaning prescribed by IFRS and therefore is unlikely to be comparable to similar measures presented by other issuers.

The following table shows the reconciliation of net earnings to adjusted net earnings for the periods shown:

		Three months ended March 31	
(millions of dollars)		2011	2010
GAAP	Net earnings	$ 626	$ 368
	Foreign exchange	(1)	(26)
	Financial instruments	8	22
	Stock-based compensation	4	(8)
	Inventory write-downs	-	2
Non-GAAP	Adjusted net earnings	$ 637	$ 358

Cautionary Note Required by National Instrument 51-101

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are 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 terms boe and mcfge 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.

Abbreviations

bbls	*barrels*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
GJ	*gigajoule*
mmbtu	*million British thermal units*
mmlt	*million long tons*
NGL	*natural gas liquids*
WTI	*West Texas Intermediate*
NYMEX	*New York Mercantile Exchange*
NIT	*NOVA Inventory Transfer*
LIBOR	*London Interbank Offered Rate*
CDOR	*Certificate of Deposit Offered Rate*
EDGAR	*Electronic Data Gathering, Analysis and Retrieval (U.S.A.)*
SEDAR	*System for Electronic Document Analysis and Retrieval (Canada)*
FPSO	*Floating production, storage and offloading vessel*
FEED	*Front end engineering design*
OPEC	*Organization of Petroleum Exporting Countries*
GDP	*Gross domestic product*
MD&A	*Management's Discussion and Analysis*
IFRS	*International Financial Reporting Standards*

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 proceeds, other assets or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid and change 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	*Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations calculated on a 12-month trailing basis*
Dated Brent	*Prices are dated less than 15 days prior to loading for delivery*
Debt to Capital Employed	*Total debt divided by total debt and shareholders' equity*
Debt to Cash Flow	*Total debt divided by cash flow from operations calculated on a 12-month trailing basis*
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*
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 an 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*
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*
Return on Capital Employed	*Net earnings plus after tax interest expense calculated on a 12-month trailing basis divided by average capital employed*
Return on Shareholders' Equity	*Net earnings calculated on a 12-month trailing basis divided by average shareholders' equity*
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*
Three Dimensional (3-D) Seismic	*Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

12. Forward-Looking Statements and Information

Certain statements in this interim report are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The 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," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts and 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 interim report include, but are not limited to: the Company's general strategic plans; growth strategies; 2011 capital expenditure plans and guidance; exploration, development and drilling plans in the Atlantic region; evaluation and exploration plans for offshore Greenland; development plans and anticipated timing of production for South Pikes Peak, Paradise Hill, and the Tucker Oil Sands Project; implementation of Phase I plans, anticipated timing of production and development plans for subsequent phases of the Sunrise Energy Project; implementation and timing of the air injection pilot project at McMullen; exploration, drilling and development plans and anticipated timing and rates of production for Western Canadian oil and gas resources plays; exploration plans, development plans, and anticipated timing of production for offshore China; expected project sanction and anticipated gas sales contracts for the Liwan development project; evaluation and exploration plans for the North Sumbawa II Exploration Block and development plans and anticipated timing of production for the Madura Block offshore Indonesia; 2011 production guidance; scheduled maintenance and turnarounds of FPSO units; timing and effect of planned turnarounds and improvements at the Company's Lima, Prince George, Toledo and Lloydminster facilities; development, implementation and timing of various enhanced recovery techniques in Western Canada; Continuous Catalyst Regeneration Reformer Project plans; development plans and anticipated timing of completion of the Hardisty storage tank; potential effect of various risk factors on the Company's operations.

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.

The Company's Annual Information Form 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 law, 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.