
Table of Contents

1. Summary of Quarterly Results
 2. Business Environment
 3. Strategic Plan
 4. Key Growth Highlights
 5. Results of Operations
 6. Liquidity and Capital Resources
 7. Risks and Risk Management
 8. Critical Accounting Estimates
 9. Recent Accounting Standards
 10. Outstanding Share Data
 11. Reader Advisories
 12. Forward-Looking Statements and Information
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1. Summary of Quarterly Results

Quarterly and Annual Financial Summary (millions of dollars, except per share amounts)	Three months ended								Year ended	
	Dec. 31 2011	Sept. 30 2011	June 30 2011	March 31 2011	Dec. 31 2010	Sept. 30 2010	June 30 2010	March 31 2010	December 31 2011	2010
Production (mboe/day)	318.9	309.1	311.6	310.4	280.5	288.7	283.9	295.9	312.5	287.1
Gross revenues ⁽¹⁾	\$ 6,154	\$ 6,219	\$ 6,454	\$ 5,662	\$ 4,490	\$ 4,472	\$ 4,630	\$ 4,493	\$24,489	\$18,085
Net earnings	408	521	669	626	139	261	179	368	2,224	947
Per share – Basic	0.42	0.55	0.73	0.70	0.16	0.31	0.21	0.43	2.40	1.11
Per share – Diluted	0.42	0.53	0.71	0.70	0.16	0.30	0.19	0.41	2.34	1.05
Cash flow from operations ⁽²⁾	1,197	1,326	1,511	1,164	685	794	739	854	5,198	3,072
Per share – Basic	1.25	1.40	1.68	1.31	0.80	0.93	0.87	1.00	5.63	3.60
Per share - Diluted	1.24	1.39	1.67	1.30	0.80	0.93	0.87	1.00	5.58	3.60

⁽¹⁾ Gross revenues have been recast to reflect a change in the treatment of intersegment sales eliminations.

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

Performance

- Production in the quarter increased by 38.4 mboe/day to 318.9 mboe/day compared with the fourth quarter of 2010 as a result of increased production at North Amethyst and Tucker, new production at the West White Rose extension and production from acquisitions that closed in Western Canada in the first quarter of 2011.
- Net earnings in the quarter increased 194% compared with the fourth quarter of 2010 due to:
 - Higher crude oil and natural gas production;
 - Higher average realized crude oil prices; and
 - Increased realized refining, upgrading and marketing margins and volumes in both Canadian and U.S. Downstream;
 - Partially offset by a pre-tax impairment charge of \$70 million related to natural gas properties in Western Canada.
- Cash flow from operations in the quarter increased by 75% to \$1,197 million compared to \$685 million in the fourth quarter of 2010.

Key Projects

- Sunrise Energy Project Phase I drilled more than half of the planned 49 horizontal well pairs and detailed engineering and construction activities for facilities and supporting infrastructure are progressing.
- Key environmental regulatory approvals received for the Liwan 3-1 and Liuhua 34-2 fields. Continued progress was made on drilling and well completion. Construction continued on the onshore gas processing plants, jacket fabrication and topsides fabrication.
- Original Gas In-Place ("OGIP") report for Liuhua 29-1 gas field approved by the Government of China.
- North Amethyst development plan application amendment filed to include the Hibernia reservoir. Drilling of one water injection well commenced to support the West White Rose two-well pilot program.
- Pikes Peak South 8,000 bbls/day heavy oil thermal project reached 80% completion.
- Western Canada oil and liquids rich gas resource play drilling progressing and additional production brought on line.

Financial

- Dividends on common shares of \$287 million in respect of the third quarter were declared during the fourth quarter of 2011 of which \$87 million and \$200 million were in cash and common shares, respectively.

2. Business Environment

Average Benchmarks		Year ended		Three months ended				
		Dec. 31		Dec. 31	Sept. 30	June 30	March 31	Dec. 31
		2011	2010	2011	2011	2011	2011	2010
WTI crude oil ⁽¹⁾	(U.S. \$/bbl)	95.12	79.46	94.06	89.76	102.56	94.10	84.89
Brent crude oil ⁽²⁾	(U.S. \$/bbl)	111.27	79.42	109.31	113.46	117.36	104.97	86.27
Canadian light crude 0.3% sulphur	(\$/bbl)	95.32	77.75	97.70	92.06	102.64	88.45	80.48
Lloyd heavy crude oil @ Lloydminster	(\$/bbl)	67.61	59.87	76.44	62.08	71.82	59.54	60.76
NYMEX natural gas ⁽³⁾	(U.S. \$/mmbtu)	4.04	4.39	3.55	4.19	4.31	4.11	3.80
NIT natural gas	(\$/GJ)	3.48	3.91	3.27	3.53	3.55	3.58	3.39
WTI/Lloyd crude blend differential	(U.S. \$/bbl)	17.44	14.48	10.73	18.12	17.89	23.11	18.37
Chicago 3:2:1 crack spread	(U.S. \$/bbl)	24.65	9.20	19.06	33.43	28.90	16.58	9.13
New York Harbour 3:2:1 crack spread	(U.S. \$/bbl)	25.26	9.64	22.05	33.72	25.32	19.34	11.41
U.S./Canadian dollar exchange rate	(U.S. \$)	1.011	0.971	0.977	1.021	1.034	1.014	0.987
Canadian Equivalents								
WTI crude oil ⁽⁴⁾	(\$/bbl)	94.09	81.83	96.27	87.91	99.19	92.80	86.01
Brent crude oil ⁽⁴⁾	(\$/bbl)	110.06	81.79	111.88	111.13	113.50	103.52	87.41
WTI/Lloyd crude blend differential ⁽⁴⁾	(\$/bbl)	17.25	14.91	10.98	17.75	17.30	22.79	18.61
NYMEX natural gas ⁽⁴⁾	(\$/mmbtu)	4.00	4.52	3.63	4.10	4.17	4.05	3.85

⁽¹⁾ Prices quoted are near-month contract prices for settlement during the next month.

⁽²⁾ Dated Brent prices are dated less than 15 days prior to loading for delivery.

⁽³⁾ Prices quoted are average settlement prices for deliveries during the period.

⁽⁴⁾ Prices quoted are calculated using U.S. benchmark commodity prices and U.S./Canadian dollar exchange rates.

Oil and Gas Prices

The price Husky receives for production from Western Canada is primarily driven by the price of West Texas Intermediate ("WTI"), adjusted to Western Canada, while the majority of the Company's production in the Atlantic Region is referenced to the price of Brent crude oil ("Brent"). The price of WTI ended 2011 at U.S. \$98.83/bbl, increasing from U.S. \$91.38/bbl on December 31, 2010. The price of WTI averaged U.S. \$94.06/bbl in the fourth quarter of 2011 compared with U.S. \$84.89/bbl in the fourth quarter of 2010. The price of WTI averaged U.S. \$95.12/bbl in 2011 compared with U.S. \$79.46/bbl in 2010. The price of Brent ended 2011 at U.S. \$106.51/bbl, increasing from U.S. \$92.55/bbl on December 31, 2010. The price of Brent averaged U.S. \$109.31/bbl in the fourth quarter of 2011 compared with U.S. \$86.27/bbl in the fourth quarter of 2010. The price of Brent averaged U.S. \$111.27/bbl in 2011 compared with U.S. \$79.42/bbl in 2010.

Canadian crude oil prices in the fourth quarter of 2011 benefited from the weakening of the Canadian dollar against the U.S. dollar as compared to the same period in 2010. In the fourth quarter of 2011, the price of WTI in U.S. dollars increased 11% versus an increase of 12% in Canadian dollars when compared to 2010. The impact of increased crude oil prices over the year were partially offset by the strengthening of the Canadian dollar against the U.S. dollar in 2011. In 2011, the price of WTI in U.S. dollars increased 20% versus an increase of 15% in Canadian dollars when compared to 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 fourth quarter of 2011, 47% of Husky's crude oil production was heavy oil or bitumen compared with 49% in the fourth quarter of 2010. The light/heavy crude oil differential averaged U.S. \$10.73/bbl or 11% of WTI in the fourth quarter of 2011 compared with U.S. \$18.37/bbl or 22% of WTI in the fourth quarter of 2010. In the twelve months ending December 31, 2011, 47% of Husky's crude oil production was heavy oil or bitumen compared with 48% in 2010. The light/heavy crude oil differential averaged U.S. \$17.44/bbl or 18% of WTI in 2011 increasing from U.S. \$14.48/bbl or 18% of WTI in 2010.

The near-month natural gas price quoted on the NYMEX ended 2011 at U.S. \$2.99/mmbtu compared with U.S. \$4.41/mmbtu at December 31, 2010. During the fourth quarter of 2011, the NYMEX near-month contract price of natural gas averaged U.S. \$3.55/mmbtu compared with U.S. \$3.80/mmbtu in the fourth quarter of 2010. During 2011, the NYMEX near-month contract price of natural gas averaged U.S. \$4.04/mmbtu compared with U.S. \$4.39/mmbtu in 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 addition, changes in foreign exchange rates impact the translation of U.S. Downstream and International Upstream operations.

The Canadian dollar ended 2010 at U.S. \$1.005 and closed at U.S. \$0.983 at December 31, 2011. In the fourth quarter of 2011, the Canadian dollar averaged U.S. \$0.977, weakening by 1% compared with U.S. \$0.987 during the fourth quarter of 2010. In 2011, the Canadian dollar averaged U.S. \$1.011 strengthening by 4% compared with U.S. \$0.971 during 2010.

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 fourth quarter of 2011, the Chicago 3:2:1 crack spread averaged U.S. \$19.06/bbl compared with U.S. \$9.13/bbl in the fourth quarter of 2010. During 2011, the Chicago 3:2:1 crack spread averaged U.S. \$24.65/bbl compared with U.S. \$9.20/bbl in 2010. During the fourth quarter of 2011, the New York Harbor 3:2:1 crack spread averaged U.S. \$22.05/bbl compared with U.S. \$11.41/bbl in the fourth quarter of 2010. During 2011, the New York Harbor 3:2:1 crack spread averaged U.S. \$25.26/bbl compared with U.S. \$9.64/bbl in 2010.

Husky's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and by the time lag between the purchase and delivery of crude oil, which is accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Global Economic and Financial Environment

In its January 10, 2012 Short-term Energy Outlook⁽¹⁾, the Energy Information Administration (“EIA”) estimated that world oil consumption increased by 1.0 mmbbls/day to 88.1 mmbbls/day in 2011. There is further expectation by the EIA that consumption will increase to reach 89.4 mmbbls/day in 2012 and 90.9 mmbbls/day in 2013. Non-members of the Organization for Economic Cooperation and Development (“OECD”), particularly China, the Middle East and Brazil, are expected by the EIA to account for most of the increase in demand over the next two years. The EIA predicts that the Organization of Petroleum Exporting Countries (“OPEC”) production will rise by 1.3 mmbbls/day over the next two years, including non-crude oil petroleum liquids. OPEC spare productive capacity, which averaged 3.0 mmbbls/day in 2011, is expected by the EIA to increase to 3.7 mmbbls/day by 2013. The EIA estimates that non-OPEC crude oil supply will increase by 1.7 mmbbls/day over the next two years primarily from U.S. shale formations, Canadian oil sands, Brazilian pre-salt, the Kashagan field in Kazakhstan and China. The EIA estimated that at the end of 2011, OECD countries held 2.6 billion barrels of commercial oil inventories. This represents approximately 56 days of forward cover. The implied volatility of WTI futures for March 2012 delivery averaged 35% establishing a lower limit of U.S. \$81.00/bbl and an upper limit of U.S. \$127.00/bbl compared with an average implied volatility of 28% a year earlier. This volatility underscores potential supply risk as crude oil production remains subject to the instability of oil producing countries in the Middle East and Africa while world demand for crude oil by the emerging economies in Asia and other non-OECD countries continues to grow.

In the EIA’s January 10, 2012 Short-term Energy Outlook, natural gas consumption in U.S. markets is expected to rise 1.3 bcf/day to reach 68.2 bcf/day in 2012 and 69.1 bcf/day in 2013. Higher consumption in the electrical generation sector is expected by the EIA to continue while natural gas prices remain low. In 2011, natural gas production in the U.S. increased by an estimated 4.5 bcf/day, primarily due to increased shale gas activity. The EIA forecasts a decline in the growth rate of U.S. domestic natural gas production to an additional 2.1 bcf/day over the next two years as lower prices begin to reduce drilling. Imports of both pipeline natural gas and liquefied natural gas into the U.S. are expected to decline by 0.6 bcf/day over the following two years. In its Weekly Natural Gas Storage Report⁽²⁾ released on January 19, 2012, the EIA reported that, as at January 13, 2012, natural gas stocks were 20.8% above the five year average and 19.6% above the previous year. The EIA expects natural gas prices to remain low in light of high production and inventories combined with a warm start to the winter heating season.

In 2011, U.S. gasoline consumption decreased by 2.7% while consumption of distillate fuel rose by 1.4% compared to 2010. Increased industrial activity was the main reason for higher distillate fuel consumption. The EIA does not expect a significant change in gasoline consumption in the next two years but continued growth in distillate fuel consumption is expected.

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 – January 10, 2012 Release.
- ⁽²⁾ “Weekly Natural Gas Storage Report”, January 19, 2012, 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 fourth 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		Effect on Annual		Effect on Annual	
	Fourth Quarter	Increase	Pre-tax Cash Flow ⁽⁶⁾		Net Earnings ⁽⁶⁾	
	Average		(\$ millions)	(\$/share) ⁽⁷⁾	(\$ millions)	(\$/share) ⁽⁷⁾
WTI benchmark crude oil price ⁽¹⁾	\$ 94.06	U.S. \$1.00/bbl	68	0.07	50	0.05
NYMEX benchmark natural gas price ⁽²⁾	\$ 3.55	U.S.\$0.20/mmbtu	22	0.02	17	0.02
WTI/Lloyd crude blend differential ⁽³⁾	\$ 10.73	U.S. \$1.00/bbl	(7)	(0.01)	(6)	(0.01)
Canadian retail margins	\$ 0.047	Cdn \$0.005/litre	16	0.02	12	0.01
Asphalt margins	\$ 22.59	Cdn \$1.00/bbl	8	0.01	6	0.01
New York Harbour 3:2:1 crack spread ⁽⁴⁾	\$ 22.05	U.S. \$1.00/bbl	74	0.08	46	0.05
Exchange rate (U.S. \$ per Cdn \$) ⁽¹⁾⁽⁵⁾	\$ 0.977	U.S. \$0.01	(54)	(0.06)	(40)	(0.04)
Interest rate		100 basis points	(1)	(0.00)	(1)	(0.00)

⁽¹⁾ Does not include gains or losses on inventory.

⁽²⁾ Includes decrease in pre-tax cash flows and 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 957.5 million common shares outstanding as of December 31, 2011.

3. Strategic Plan

Husky's strategy is to maintain production in its foundation of Western Canada and Heavy Oil and reposition these areas to resource play and thermal development, while advancing its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands. 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 heavy oil and bitumen 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 was built 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 Asia Pacific Region, the Atlantic Region and the Oil Sands.

4.1 Upstream

Asia Pacific Region

Offshore China Exploration, Delineation and Development

Regulatory approvals in relation to environmental matters and civil construction were received for the Liwan Gas Project in the fourth quarter of 2011. Construction of the onshore gas plant is progressing. Project execution is accelerating and proceeding on schedule towards planned first production in late 2013/early 2014.

In December 2011, the OGIP report for the Liuhua 29-1 gas field was approved by the Government of China. Front end engineering design ("FEED") for the development of this field will commence in February 2012.

Husky completed drilling the Yacheung 5-1-1 exploration well on Block 63/05 in the Qiongdongnan Basin. The exploration well was drilled to a total depth of 3,620 meters. However, commercial hydrocarbons were not encountered and the well was plugged and abandoned.

Indonesia Exploration and Development

Tendering of the facilities, equipment and services for the Madura BD field development in the Madura Straits Block progressed during the fourth quarter. Drilling of the MBH-1 exploration well was successful with a new discovery of gas resources. The well was tested at rates up to 18.1 mmcf/day. A Plan of Development contemplating a cluster development with the MDA field is expected to be filed in 2012. First gas production from the Madura Straits Block is expected in 2014.

Atlantic Region

White Rose Extension Projects

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

At the end of December 2011, the North Amethyst field had three production wells and three water injection wells on stream. During the fourth quarter of 2011, Husky filed an application to amend the development plan for North Amethyst to include the Hibernia reservoir. In 2012, Husky plans to continue development drilling at North Amethyst and to drill an infill well at the main White Rose field to facilitate incremental oil recovery from this reservoir.

The Company continues to evaluate the feasibility of a concrete wellhead and drilling platform for development of future resources in the White Rose region including the full development of West White Rose. Pre-FEED and FEED contracts to support this work are expected to be awarded in the first quarter of 2012.

Atlantic Region Exploration

Husky participated in a Statoil-operated exploration well at the Fiddlehead prospect south of Terra Nova in the fourth quarter of 2011. The results of the program are being evaluated. Husky holds a 50% working interest in the well.

Offshore Greenland

Husky has a significant position in three blocks off the west coast of Greenland. Geological and geophysical work continues in order to define potential well locations.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. Phase I of the project remains on schedule for first production in 2014. To date, Husky has drilled more than half of the 49 Steam-Assisted Gravity Drainage ("SAGD") horizontal well pairs for Phase I of the project and is on track for the full drilling program to be completed by the second half of 2012. The Central Processing Facility contractor continued foundation installation. The first major equipment delivery was completed in January 2012.

Detailed engineering activities for facilities and supporting infrastructure continued and construction activities for field facilities also progressed in the fourth quarter. Construction of the camp continued through the fourth quarter of 2011 and it is expected to be available for use in the first quarter of 2012.

A contract for the Design Basis Memorandum and FEED for the next development stage of the Sunrise Energy Project

was awarded in October 2011 with FEED expected to be completed in 2013.

Tucker Project

Husky has addressed the subsurface challenges at Tucker by remediating older wells with new completion and stimulation techniques, drilling new wells and initiating revised start up procedures. Production during the fourth quarter of 2011 averaged approximately 9,400 bbls/day.

McMullen

During the fourth quarter of 2011, 32 slant development wells were drilled at McMullen and a total of eight slant wells were equipped, completed and placed on production. All wells are expected to be equipped, completed and placed on production in the first quarter of 2012. An additional 10 evaluation wells were drilled to further delineate the primary production development area.

At the McMullen air injection pilot, steam injection commenced in September 2011 with first air injection successfully initiated in December 2011.

Saleski

The evaluation of the information from the vertical stratigraphic test wells and two-dimensional ("2-D") seismic data obtained earlier in 2011 continued. Additional stratigraphic test wells are planned for 2012.

Heavy Oil

Construction of the 8,000 bbls/day Pikes Peak South thermal project is progressing within original cost estimates and on schedule. First oil is expected by mid-2012. The project was 80% complete at the end of 2011.

Construction continued on the 3,000 bbls/day Paradise Hill development which will utilize existing Bolney infrastructure. The project is on schedule and was 80% complete at the end of 2011. First oil is expected by the third quarter of 2012.

Rush Lake, a single well pilot pair, achieved first oil in October 2011. Design of a Rush Lake commercial project is now underway. The planning process is ongoing for three additional commercial thermal projects which are in the early stages of reservoir evaluation and concept selection.

The 2011 horizontal drilling program continued with the completion of the planned 130 well program during the fourth quarter of 2011. Based on the positive performance of the programs, Husky is planning to drill 140 wells in 2012.

Ninety cold heavy oil production with sand ("CHOPS") wells were drilled during the fourth quarter of 2011.

Four solvent Enhanced Oil Recovery ("EOR") pilots are currently operating. Field results have demonstrated technical success. A CO₂ capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with commissioning expected in the first quarter of 2012. All CO₂ from the Ethanol Plant is expected to be used in the ongoing solvent EOR piloting program.

Western Canada (excluding Heavy Oil and Oil Sands)

Gas Resource Plays

At Ansell, a liquids rich resource play in west central Alberta, seven Cardium wells and three multi-zone wells were drilled in the fourth quarter of 2011. Completion operations recommenced in mid-October 2011. An offtake capacity expansion was commissioned in October 2011.

A horizontal drilling program was initiated in the fourth quarter to evaluate the Duvernay liquids-rich gas play at Kaybob. The first well was rig released in November 2011. A second well is currently being drilled. Completion of both wells is expected to occur in 2012.

Three wells in the multi-zone program at Kakwa were drilled, and placed on production in 2011.

Oil Resource Plays

During the fourth quarter of 2011, 35 wells were drilled across the entire oil resource play portfolio. Additional land was acquired during the quarter, bringing the overall oil resource play land position to approximately 800,000 net acres.

At the Oungre Bakken project in southeast Saskatchewan, five horizontal wells were drilled in the fourth quarter of 2011.

At the Redwater Viking oil resource project, eight horizontal wells, in which Husky has a 87% working interest, were drilled during the fourth quarter of 2011. The majority of the 2011 wells are awaiting tie-in and are expected to be on production in the first quarter of 2012.

In the southwestern Saskatchewan Viking oil resource project, 10 horizontal wells were drilled in the fourth quarter of 2011. Approximately 50 wells are planned for the Redwater and Saskatchewan Viking plays in 2012.

In the Shaunavon oil resource play, five gross wells, in which Husky has a 56% working interest, are planned for 2012.

Two northern Cardium oil resource pilot projects at Wapiti and Kakwa are being appraised. At Wapiti, four operated horizontal Cardium wells have been drilled with two wells completed. At Kakwa, four horizontal Cardium wells have been drilled, in which Husky has 63% working interest. Completion operations for the remaining six horizontal pilot wells will commence in the first quarter of 2012.

In the fourth quarter of 2011, Husky drilled two additional vertical pilot wells and two horizontal wells at the Rainbow Muskwa project. Along with a vertical pilot well drilled during the third quarter of 2011, it is anticipated that these wells will provide information for resource and reservoir characterization across the Rainbow area. One of the horizontal wells was completed in the fourth quarter and is undergoing post fracture clean up. Husky holds a significant acreage position in this emerging oil resource play which compliments its wholly owned infrastructure at Rainbow Lake.

In the Northwest Territories, Husky's Canol shale project received regulatory approvals for the construction and drilling operations of two vertical pilot wells. These vertical wells, which Husky expects to drill in the first quarter of 2012, will collect valuable data to assess reservoir characterization and resource scope.

4.2 Midstream

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

4.3 Downstream

Lima, Ohio Refinery

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

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is progressing as planned. Overall detailed engineering and procurement is complete and construction activities continued during the fourth quarter of 2011. All heavy haul transports have been completed and equipment is being installed at the site. 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 Dec. 31		Year ended Dec. 31	
	2011	2010	2011	2010
<i>(millions of dollars)</i>				
Gross revenues	\$ 1,984	\$ 1,487	\$ 7,250	\$ 5,744
Royalties	331	211	1,125	978
Net revenues	1,653	1,276	6,125	4,766
Operating, transportation and administration expenses	469	419	1,890	1,595
Exploration and evaluation expenses	194	233	470	438
Depletion, depreciation, amortization and impairment	590	406	1,996	1,521
Other (income) expense	2	(2)	(263)	1
Income taxes	105	63	530	350
Net earnings	\$ 293	\$ 157	\$ 1,502	\$ 861

Fourth Quarter

Upstream net earnings in the fourth quarter of 2011 increased by \$136 million compared with the fourth quarter of 2010 primarily as a result of increased crude oil and natural gas production, higher realized crude oil prices and lower exploration and evaluation expenses, partially offset by lower realized natural gas prices and higher royalties, operating expenses and depletion, depreciation, amortization and impairment.

Production increased by 38.4 mboe/day due to increased production at North Amethyst and Tucker, new production at the West White Rose pilot and production from acquisitions completed in the first quarter of 2011.

The average realized price in the fourth quarter of 2011 was \$88.97/bbl for crude oil, NGL and bitumen compared with \$68.87/bbl during the same period in 2010. Realized natural gas prices averaged \$3.24/mcf in the fourth quarter of 2011 compared with \$3.52/mcf in the same period in 2010. Production in the Atlantic Region and Asia Pacific Region benefited from higher realized prices as the price of Brent increased by approximately 27% while WTI increased by approximately 11% compared with the fourth quarter of 2010.

Twelve Months

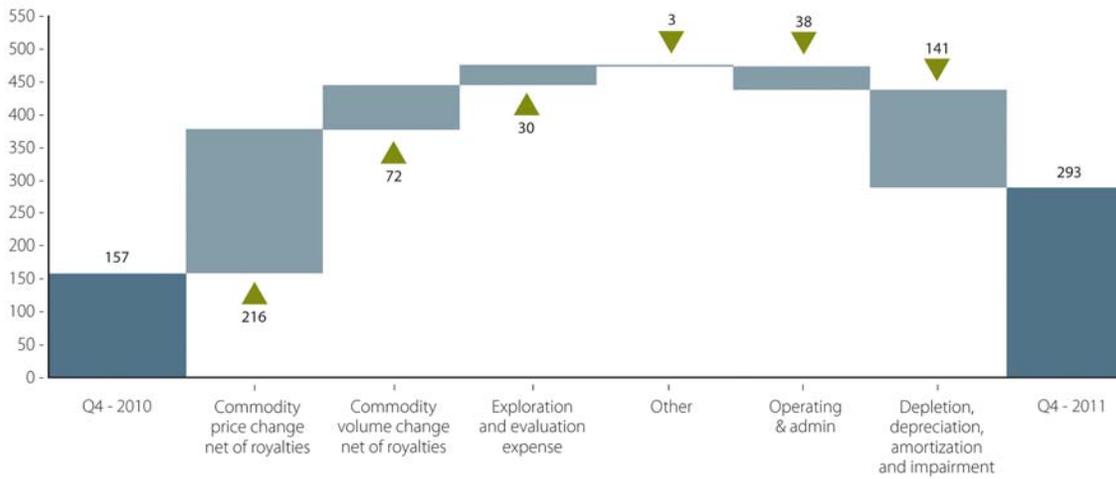
Upstream net earnings in 2011 were \$641 million higher compared with 2010 primarily as a result of increased crude oil and natural gas production, higher realized crude oil prices and realized gains on the sale of assets, partially offset by lower realized natural gas prices and higher exploration and evaluation expenses, operating expenses and depletion, depreciation, amortization and impairment.

During 2011, average realized prices increased 24% to \$82.72/bbl for crude oil, NGL and bitumen combined compared with \$66.70/bbl during 2010 while average realized natural gas prices decreased 8% to \$3.55/mcf during 2011 compared to \$3.86/mcf in 2010.

Upstream After Tax Variance Analysis

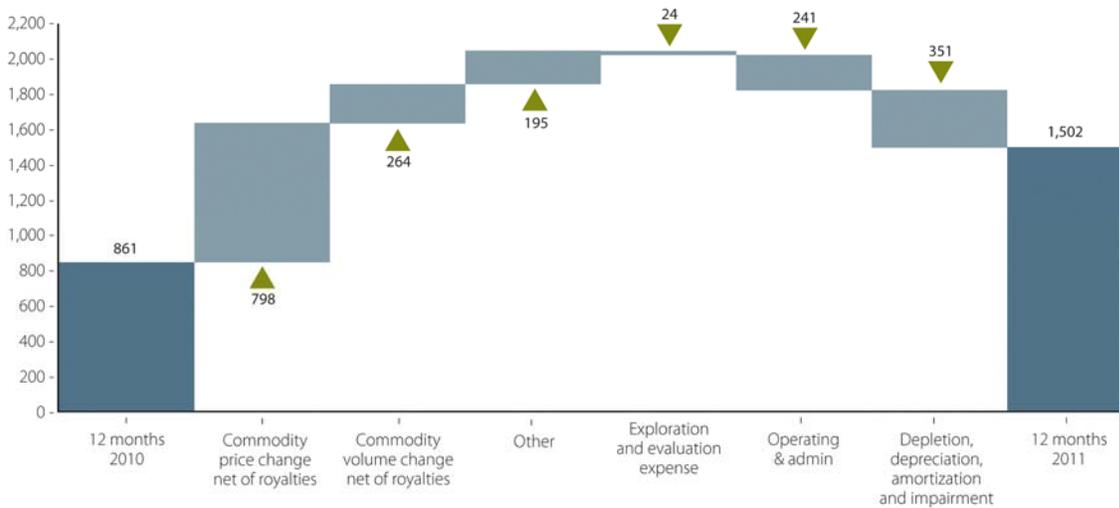
Fourth Quarter

Upstream After Tax Earnings Variance Analysis
(\$millions)



Twelve Months

Upstream After Tax Earnings Variance Analysis
(\$millions)



Pricing

Average Sales Prices Realized		Three months ended Dec. 31		Year ended Dec. 31	
		2011	2010	2011	2010
Crude oil	<i>(\$/bbl)</i>				
Light crude oil & NGL		\$ 105.97	\$ 82.90	\$ 103.25	\$ 76.90
Medium crude oil		84.32	65.75	75.65	64.92
Heavy crude oil		75.60	58.82	66.99	58.91
Bitumen		73.24	59.14	64.34	57.84
Total average		88.97	68.87	82.72	66.70
Natural gas average	<i>(\$/mcf)</i>	3.24	3.52	3.55	3.86
Total average	<i>(\$/boe)</i>	67.53	55.21	63.23	54.25

The price realized for light crude oil reflects increases in WTI and the significant premium realized for offshore production referenced to Brent prices. Western Canada light and synthetic oils were trading at a higher premium to WTI compared to 2010 due to logistical constraints and

regional oversupply at Cushing, Oklahoma. 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 Dec. 31		Year ended Dec. 31	
		2011	2010	2011	2010
Crude oil & NGL	<i>(mmbbls/day)</i>				
Western Canada					
Light crude oil & NGL		28.8	23.0	24.8	23.0
Medium crude oil		24.3	25.3	24.5	25.4
Heavy crude oil		75.8	74.6	74.5	74.5
Bitumen		27.4	23.1	24.7	22.3
		156.3	146.0	148.5	145.2
Atlantic Region					
White Rose and Satellite Fields - light crude oil		49.6	34.2	48.7	38.2
Terra Nova - light crude oil		5.0	7.1	5.6	8.5
China					
Wenchang - light crude oil & NGL		8.3	10.8	8.5	10.7
Total crude oil & NGL		219.2	198.1	211.3	202.6
Natural gas	<i>(mmcf/day)</i>	597.9	494.2	607.0	506.8
Total	<i>(mboe/day)</i>	318.9	280.5	312.5	287.1

Crude Oil and NGL Production

Fourth Quarter

Crude oil and NGL production in the fourth quarter of 2011 increased by 21.1 mbbls/day or 11% compared with the same period in 2010. The increase was primarily due to increased production at the North Amethyst field, first production at the West White Rose two well pilot program, higher production at Tucker due to revised drilling techniques initiated during the year and production from acquisitions that closed in the first quarter of 2011.

Twelve Months

In 2011, crude oil and NGL production increased by 4% compared with 2010, primarily due to the same factors impacting the fourth quarter, partially offset by operational issues at Terra Nova.

Natural Gas Production

Natural gas production increased by 103.7 mmcf/day or 21% in the fourth quarter of 2011 compared with the same period in 2010 due to the acquisitions of properties in Western Canada during the first quarter of 2011, partially

offset by natural reservoir declines in mature properties as capital investment has been focused on higher return projects.

2011 Production Guidance		Guidance	Actual Production	
			Year ended Dec. 31 2011	Year ended Dec. 31 2010
Crude oil & NGL	(mbbls/day)			
Light crude oil & NGL		75 – 80	88	81
Medium crude oil		25 – 30	24	25
Heavy crude oil & bitumen		95 – 105	99	97
		195 – 215	211	203
Natural gas	(mmcf/day)	560 – 610	607	507
Natural gas	(mboe/day)	93 – 102	101	84
Total barrels of oil equivalent	(mboe/day)	290 – 315	312	287

Royalties

Fourth Quarter

In the fourth quarter of 2011, royalty rates as a percentage of gross revenue averaged 17% compared with 15% in 2010. Royalty rates in Western Canada averaged 14% in the fourth quarter of 2011 compared to 13% in the same period in 2010. Royalty rates for the Atlantic Region averaged 19% in the fourth quarter of 2011 up from 18% in the fourth quarter of 2010. Royalty rates in the Asia Pacific Region averaged 31% in the fourth quarter of 2011 compared with 24% in the fourth quarter of 2010 due to price increases combined with a sliding scale price sensitive rate.

Twelve Months

Royalty rates averaged 16% of gross revenue in 2011 compared with 17% in 2010. Rates in Western Canada averaged 14% in 2011 compared with 15% in 2010. The average royalty rate was 17% in 2011 compared with 24% in 2010 for the Atlantic Region. Rates at North Amethyst will increase and reach the same level as White Rose once certain project payouts prescribed in the royalty regulations are met. Royalty rates in the Asia Pacific Region averaged 30% in 2011 compared with 23% in 2010. The change in rates for 2011 was due to the same factors impacting the fourth quarter.

Operating Costs

<i>(millions of dollars)</i>	Three months ended Dec. 31		Year ended Dec. 31	
	2011	2010	2011	2010
Western Canada	\$ 383	\$ 310	\$ 1,462	\$ 1,199
Atlantic Region	43	44	174	176
Asia Pacific Region	7	6	25	24
Total	\$ 433	\$ 360	\$ 1,661	\$ 1,399
Unit operating costs (\$/boe)	\$ 14.75	\$ 13.94	\$ 14.56	\$ 13.35

Fourth Quarter

Total Upstream operating costs in the fourth quarter of 2011 increased to \$433 million from \$360 million in the fourth quarter of 2010 as a result of increased fuel and electrical costs combined with treating, maintenance and labour costs that were impacted by acquisitions in the first quarter of 2011. Total Upstream unit operating costs in the fourth quarter of 2011 averaged \$14.75/boe compared with \$13.94/boe in the fourth quarter of 2010.

Operating costs in Western Canada averaged \$16.26/boe in the fourth quarter of 2011 compared with \$14.76/boe in the same period in 2010. The impact of higher operating costs in 2011 was partially offset by the effect of an increase in production volumes. Acquisitions in the first quarter of 2011 increased fuel and electrical costs along with increased costs associated with custom processing, maintenance and labour when compared to the fourth quarter of 2010. Higher handling costs of produced fluids resulted from increased water and emulsion production in the fourth quarter of 2011. Maturing fields in Western Canada require more extensive infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive gathering systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs

associated with the increased infrastructure through cost reduction and efficiency initiatives and by fully utilizing infrastructures in place.

Operating costs in the Atlantic Region averaged \$8.54/boe in the fourth quarter of 2011 compared with \$11.43/boe in the fourth quarter of 2010. The decrease was the result of increased production from North Amethyst and West White Rose in the fourth quarter of 2011 compared with the fourth quarter of 2010.

Operating costs at the Asia Pacific Region averaged \$9.18/bbl in the fourth quarter of 2011 compared with \$6.28/bbl in the same period in 2010. This increase was the result of lower production and higher maintenance costs in the fourth quarter of 2011 compared with the same period in 2010.

Twelve Months

Total Upstream operating costs in 2011 increased compared with 2010 primarily due to acquisitions in the fourth quarter of 2010 and first quarter of 2011, and the same factors affecting the fourth quarter.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses Summary <i>(millions of dollars)</i>	Three months ended Dec. 31		Year ended Dec. 31	
	2011	2010	2011	2010
Seismic, geological and geophysical	\$ 68	\$ 79	\$ 170	\$ 186
Expensed drilling	124	154	245	252
Expensed land	2	-	55	-
Total	\$ 194	\$ 233	\$ 470	\$ 438

Fourth Quarter

Exploration and evaluation expenses for the fourth quarter of 2011 were \$194 million compared with \$233 million in the fourth quarter of 2010 primarily due to lower expensed drilling and seismic costs. Expensed drilling in the fourth quarter of 2011 related to wells drilled in Canada and the Asia Pacific Region which did not encounter economic quantities of oil and gas.

Twelve Months

Exploration and evaluation expenses in 2011 were \$470 million compared to \$438 million during 2010. Land costs of \$43 million relating to the Columbia River Basin located in the states of Washington and Oregon were expensed in the second quarter of 2011.

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

Fourth Quarter

In the fourth quarter of 2011, total DD&A averaged \$20.12/boe compared with \$15.70/boe in the fourth quarter of 2010. The increased DD&A rate in the fourth quarter of 2011 was primarily due to higher production from the North Amethyst offshore project and an impairment charge of \$70 million on conventional natural gas properties located in East Central Alberta.

Twelve Months

During 2011, total DD&A averaged \$17.51/boe compared with \$14.52/boe during 2010 due to the same factors affecting the fourth quarter.

Upstream Capital Expenditures

Capital Expenditures Summary ⁽¹⁾	Three months Dec. 31		Year ended Dec. 31	
	2011	2010	2011	2010
<i>(millions of dollars)</i>				
Exploration				
Western Canada	\$ 87	\$ 63	\$ 233	\$ 344
Atlantic Region	-	7	2	68
Asia Pacific Region	37	65	168	229
	124	135	403	641
Development				
Western Canada	734	562	2,050	1,334
Atlantic Region	61	71	258	375
Asia Pacific Region	226	59	546	62
	1,021	692	2,854	1,771
Acquisitions				
Western Canada	14	325	874	400
	\$ 1,159	\$ 1,152	\$ 4,131	\$ 2,812

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

In 2011, Upstream capital expenditures were \$4,131 million. Capital expenditures were \$714 million (17%) in the Asia Pacific Region, \$260 million (6%) in the Atlantic Region and

\$3,157 million (77%) in Western Canada including acquisitions of \$874 million. Husky's major projects remain on budget and schedule.

Asia Pacific Region

The following table discloses Husky's offshore China and Indonesia drilling activity completed during 2011:

Asia Pacific Region Offshore Drilling Activity			
China			
Liuhua 29-1-4 Block 29/26	WI 100% ⁽¹⁾	Stratigraphic test	Delineation
Liuhua 29-1-5 Block 29/26	WI 100% ⁽¹⁾	Stratigraphic test	Delineation
Liuhua 32-1-1 Block 29/26	WI 100% ⁽¹⁾	Stratigraphic test	Exploratory
Liwan 5-1-1 Block 29/26	WI 100% ⁽¹⁾	Stratigraphic test	Exploratory
Liwan 4-3-1 Block 29/26	WI 100% ⁽¹⁾	Stratigraphic test	Exploratory
Yacheung 5-1-1 Block 63/05	WI 100% ⁽¹⁾	Stratigraphic test	Exploratory
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
Wenchang 13-2-A4h1 side track	WI 40%	Production	Development
Indonesia			
MDA-4 Madura Strait	WI 40%	Stratigraphic test	Exploratory
MBH-1 Madura Strait	WI 40%	Stratigraphic test	Exploratory

⁽¹⁾ CNOOC has the right to participate in development of discoveries up to 51%.

During 2011, total capital expenditures of \$714 million were invested in the Asia Pacific Region of which \$700 million was attributed to China primarily on offshore projects and \$14

million was attributed to the Madura Strait of Indonesia related to two exploratory wells.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2011:

Offshore Atlantic Region Drilling Activity			
North Amethyst G-25-5	WI 68.875%	Water injection	Development
North Amethyst G-25-6	WI 68.875%	Production	Development
White Rose E-18-10 (West pilot)	WI 68.875%	Production	Development
Mizzen F-09	WI 35%	Exploratory	Exploratory
Fiddlehead D-83	WI 50%	Exploratory	Exploratory

During 2011, \$260 million was invested in Atlantic Region development projects, primarily drilling of water injection and production wells in North Amethyst. Two exploration wells

were drilled in the Atlantic Region in 2011, one in the Flemish Pass Basin and one located south of the Terra Nova field.

Western Canada, Heavy Oil and Oil Sands

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

Western Canada, Heavy Oil and Oil Sands Wells Drilled		Three months ended Dec. 31				Year ended Dec. 31			
		2011		2010		2011		2010	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	20	19	15	12	50	40	60	51
	Gas	11	11	11	9	24	24	37	31
	Dry	-	-	-	-	3	3	8	8
		31	30	26	21	77	67	105	90
Development	Oil	228	196	283	257	880	765	815	722
	Gas	7	4	46	38	57	42	73	53
	Dry	-	-	2	2	4	4	10	9
		235	200	331	297	941	811	898	784
Total		266	230	357	318	1,018	878	1,003	874

Western Canada

During 2011, Husky invested \$2,307 million on exploration, development and acquisitions throughout the Western Canada Sedimentary Basin compared with \$1,438 million in 2010. Property acquisitions of \$874 million were completed during 2011, primarily in the Rainbow Lake area of northwestern Alberta, the Foothills and Deep Basin areas of Alberta and in northeastern British Columbia.

The Company drilled 878 net wells in the Western Canada Sedimentary Basin in 2011 resulting in 805 net oil wells and 66 net natural gas wells compared with 874 net wells resulting in 773 net oil wells and 84 net natural gas wells in 2010. Capital expenditures for wells drilled in Western Canada increased substantially in 2011 compared with 2010 due to the increased focus on resource development drilling in areas such as the Ansell liquids rich gas resource play, larger numbers of horizontal wells drilled and more multi-stage fracture completions performed. The decrease in the number of development wells drilled during the fourth quarter of 2011 compared to the same period in 2010 is reflective of the shift in strategic focus from CHOPS wells towards new opportunities in horizontal drilling and thermal projects in heavy oil.

In 2011, \$591 million was invested in oil related exploration and development and \$359 million was invested in natural gas related exploration and development compared with \$410 million for oil related exploration and development and \$163 million for natural gas related exploration and development in 2010.

In addition, \$176 million was spent on production optimization and cost reduction initiatives in 2011. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled \$307 million.

Heavy Oil

During 2011, capital expenditures on heavy oil projects were \$587 million related to thermal projects, CHOPS drilling and horizontal drilling as compared to \$469 million in 2010.

Oil Sands

During 2011, capital expenditures on Oil Sands projects were \$263 million compared with \$171 million in 2010 as Sunrise Phase I progresses.

Upstream Planned Turnarounds

Husky intends to proceed with an offstation for the SeaRose FPSO propulsion system in the second and third quarters of 2012 which is expected to last approximately 125 days. Production from the White Rose, North Amethyst and West White Rose fields will be shut-in during the offstation maintenance. The impact to Husky's production, averaged over the year, is forecasted to be approximately 12,000 bbls/day.

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

5.2 Midstream

Infrastructure and Marketing Net Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
		2011	2010	2011	2010
<i>(millions of dollars, except where indicated)</i>					
Gross revenues		\$ 2,436	\$ 1,700	\$ 9,446	\$ 7,002
Gross margin	- pipeline	\$ 40	\$ 31	\$ 150	\$ 124
	- other infrastructure and marketing	75	71	255	193
Operating and administration expenses		115	102	405	317
Depreciation and amortization		6	6	25	21
Other expenses		17	13	46	43
Income taxes		2	20	6	34
Net earnings		22	17	82	59
Net earnings		\$ 68	\$ 46	\$ 246	\$ 160
Selected operating data:					
Commodity volumes managed	<i>(mboe/day)</i>	1,048	1,021	1,028	952
Aggregate pipeline throughput	<i>(mbbls/day)</i>	548	501	559	512

Fourth Quarter

Infrastructure and Marketing net earnings in the fourth quarter of 2011 were \$68 million compared with \$46 million in the same period in 2010. The increase in net earnings was primarily due to higher pipeline throughputs and marketed volumes, 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 in the fourth quarter of 2011 compared with the same period

in 2010 due to timing of realized gains on natural gas storage contracts.

Twelve Months

During 2011, Infrastructure and Marketing net earnings were \$86 million higher than in 2010 primarily due to the same factors that affected the fourth quarter of 2011 in addition to trading gains captured on light and synthetic crude oil moving from Canada to the U.S. as a result of a widened WTI to Brent differential.

Midstream Capital Expenditures

In 2011, Midstream capital expenditures totalled \$43 million compared to \$40 million in 2010. The majority of midstream capital expenditures during the year related to

the construction of the 300,000 barrel tank at the Hardisty terminal.

5.3 Downstream

Effective 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	Three months ended Dec. 31		Year ended Dec. 31		
	2011	2010	2011	2010	
<i>(millions of dollars, except where indicated)</i>					
Gross revenues	\$ 615	\$ 366	\$ 2,217	\$ 1,570	
Gross margin	\$ 152	\$ 77	\$ 636	\$ 311	
Operating and administration expenses	40	47	191	185	
Depreciation and amortization	25	35	164	74	
Other expense (income)	26	(32)	74	(37)	
Income taxes	16	8	54	26	
Net earnings (loss)	\$ 45	\$ 19	\$ 153	\$ 63	
Selected operating data:					
Upgrader throughput ⁽¹⁾	<i>(mbbls/day)</i>	76.3	55.7	69.6	65.4
Synthetic crude oil sales	<i>(mbbls/day)</i>	58.2	45.1	55.3	54.1
Upgrading differential	<i>(\$/bbl)</i>	\$ 22.32	\$ 16.39	\$ 27.34	\$ 14.52
Unit margin	<i>(\$/bbl)</i>	\$ 28.39	\$ 18.55	\$ 31.51	\$ 15.73
Unit operating cost ⁽²⁾	<i>(\$/bbl)</i>	\$ 6.22	\$ 9.19	\$ 7.40	\$ 7.76

⁽¹⁾ Throughput includes diluent returned to the field.

⁽²⁾ Based on throughput.

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

Fourth Quarter

Upgrading net earnings in the fourth quarter of 2011 were \$45 million compared with \$19 million in the same period in 2010. The increase was primarily due to higher realized differentials and higher production due to improved reliability and a turnaround in the fourth quarter of 2010. During the fourth quarter of 2011, the upgrading differential averaged \$22.32/bbl, an increase of \$5.93/bbl or 36% compared with the fourth quarter of 2010. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The average price for Husky Synthetic Blend in the fourth quarter of 2011 was \$104.44/bbl compared to \$83.46/bbl in the fourth quarter of 2010. The overall unit margin increased to \$28.39/bbl in the fourth quarter of 2011 from \$18.55/bbl in the same period in 2010 primarily as a result of wider heavy to light crude oil price differentials. The increase in other expenses is due to the increase in the fair value of the

remaining upside interest payment obligation to Natural Resources Canada and the Alberta Department of Energy as a result of higher upgrading differentials.

Twelve Months

Upgrading earnings for 2011 were affected by the same factors impacting the fourth quarter, in addition to a minor fire at the Lloydminster Upgrader in early February which resulted in a reduction in average throughput at the Upgrader to 53.2 mbbls/day in the first quarter of 2011. The increase in depreciation and amortization was due to turnaround costs from the fall of 2010, which were depreciated starting in the fourth quarter of 2010, and the derecognition of certain intangible costs.

Canadian Refined Products Net Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
		2011	2010	2011	2010
<i>(millions of dollars, except where indicated)</i>					
Gross revenues		\$ 938	\$ 835	\$ 3,860	\$ 2,975
Gross margin	- fuel	\$ 41	\$ 39	\$ 149	\$ 87
	- refining	23	17	90	64
	- asphalt	42	34	204	160
	- ancillary	11	11	49	46
Operating and administration expenses		117	101	492	357
Depreciation and amortization		33	24	117	110
Income taxes		20	17	80	88
Net earnings		16	16	75	42
Selected operating data:					
	Number of fuel outlets (average)	548	551	547	508
	Light oil sales <i>(million litres/day)</i>	9.4	8.7	9.5	8.2
	Light oil retail sales per outlet <i>(thousand litres/day)</i>	17.1	13.9	17.3	13.8
	Prince George Refinery throughput <i>(mbbls/day)</i>	11.1	11.5	10.6	10.0
	Asphalt sales <i>(mbbls/day)</i>	20.1	27.5	25.3	24.1
	Lloydminster Refinery throughput <i>(mbbls/day)</i>	29.0	29.0	28.1	27.8
	Ethanol production <i>(thousand litres/day)</i>	751.9	691.4	711.3	619.7

Fourth Quarter

Gross margins on fuel sales were marginally higher in the fourth quarter of 2011 compared with the same period in 2010 as a result of higher distillate margins due to constrained distillate supply.

Higher refining gross margins in the fourth quarter of 2011 were primarily due to higher market crack spreads, higher total ethanol production from improved reliability at the Lloydminster Ethanol Plant and higher realized prices for gasoline, diesel and ethanol, partially offset by lower production at the Prince George Refinery due to turnaround activities and crude shortages.

Included in refining gross margins in the fourth quarter of 2011 and 2010 are government assistance grants of \$10 million and \$9 million, respectively.

Asphalt gross margins were higher in the fourth quarter of 2011 compared with the fourth quarter of 2010 due to higher realized market prices as a result of strong demand for drilling fluids and record production levels achieving an on-stream factor of 99% for the quarter. Volumes reflect normal seasonal trends.

Twelve Months

During 2011, refined products earnings were higher than in 2010 primarily due to the same factors that affected the fourth quarter of 2011.

U.S. Refining and Marketing Net Earnings Summary

	Three months ended Dec. 31		Year ended Dec. 31		
	2011	2010	2011	2010	
<i>(millions of dollars, except where indicated)</i>					
Gross revenues	\$ 2,371	\$ 1,824	\$ 9,593	\$ 7,107	
Gross refining margin	\$ 280	\$ 181	\$ 1,290	\$ 547	
Operating and administration expenses	104	96	400	386	
Interest – net	1	-	2	2	
Depreciation and amortization	52	51	195	191	
Income taxes (recoveries)	45	12	253	(12)	
Net earnings (loss)	\$ 78	\$ 22	\$ 440	\$ (20)	
Selected operating data:					
Lima Refinery throughput	<i>(mbbls/day)</i>	142.9	113.9	144.3	136.6
Toledo Refinery throughput	<i>(mbbls/day)</i>	64.4	64.6	63.9	64.4
Realized refining margin	<i>(U.S. \$/bbl crude throughput)</i>	\$ 14.80	\$ 10.97	\$ 17.60	\$ 7.29
Refinery feedstocks and refined products inventory	<i>(mmbbls)</i>	11.8	11.9	11.8	11.9

Fourth Quarter

U.S. Refining and Marketing net earnings increased significantly in the fourth quarter of 2011 compared with the fourth quarter of 2010 as a result of higher realized refining margins including FIFO inventory gains. In addition to increased market crack spreads, feedstock at the Toledo Refinery was approximately half heavy crude oil which added to increased margins as differentials between heavy and light crude oil remained high in the fourth quarter of 2011. The increase in net earnings was partially offset at the Lima Refinery where over half of the feedstock is based on the price of Brent, crude supply constraints due to the Enbridge pipeline construction, and planned maintenance at the Toledo Refinery.

The Chicago crack spread benchmark is based on last in first out (“LIFO”) accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were lower.

In addition, the product slates 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 weakening of the Canadian dollar versus the U.S. dollar in the fourth quarter of 2011 compared with the same period in 2010 had a positive impact on the translation of U.S. dollar financial results into Canadian dollars.

Twelve Months

Refining margins in 2011 were mainly impacted by the same factors affecting the fourth quarter. In addition, an overall strengthening of the Canadian dollar versus the U.S. dollar in 2011 had a negative impact on the translation of U.S. dollar financial results into Canadian dollars in 2011.

Downstream Capital Expenditures

In 2011, Downstream capital expenditures totalled \$373 million compared with \$682 million in 2010.

In Canada, capital expenditures were \$149 million related to upgrades at the Prince George Refinery, the Upgrader and retail stations.

In the United States, capital expenditures totalled \$224 million. At the Lima Refinery, \$124 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled \$100 million (Husky's 50% share) primarily for engineering work and procurement on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

An outage is scheduled for approximately three weeks in the first half of 2012 at the Upgrader to expedite hydrogen plant repairs and catalyst change out. 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 is expected to be shutdown for 21 days during the turnaround for inspections and equipment repair.

The Toledo Refinery is scheduled to have a minor turnaround in mid-2012. The partial outage is expected to last approximately 21 days.

The Lima Refinery is scheduled to have a 15-day Diesel Hydrotreater outage in the fourth quarter of 2012 to replace the catalyst. In addition, a 29-day aromatics turnaround is expected in the fourth quarter of 2012. Neither of the planned outages are expected to have a material impact on crude throughputs. The Lima Refinery is scheduled to complete a major turnaround in 2014 on 70% of the operating units. The refinery is expected to be shutdown for 45 days during the turnaround. The remaining 30% of the operating units will be addressed in a major turnaround currently planned for 2015.

5.4 Corporate

Corporate Summary	Three months ended Dec. 31		Year ended Dec. 31	
<i>(millions of dollars) income (expense)</i>	2011	2010	2011	2010
Intersegment eliminations - net	\$ (83)	\$ (61)	\$ (51)	\$ (47)
Administration expense	(48)	(42)	(199)	(88)
Other income (expense)	8	(1)	3	3
Stock-based compensation	(7)	(6)	1	13
Exploration and evaluation expenses	-	3	-	-
Depreciation and amortization	(12)	(19)	(38)	(75)
Interest - net	(22)	(58)	(141)	(186)
Foreign exchange gains (losses)	(15)	(76)	10	(49)
Income taxes	55	111	78	195
Net loss	\$ (124)	\$ (149)	\$ (337)	\$ (234)

Fourth Quarter

The Corporate segment reported a loss of \$124 million in the fourth quarter of 2011 compared with a loss of \$149 million in the fourth quarter of 2010. Interest - net decreased by \$36 million as compared to the fourth quarter of 2010 due to increased amounts capitalized related to projects in the Asia Pacific Region. Foreign exchange was a loss of \$15 million during the fourth quarter of 2011 compared with a loss of \$76 million in the same period of 2010 due to a weakening of the Canadian dollar against the U.S. dollar which impacted the translation of U.S. denominated debt. Intersegment eliminations are net earnings related to inventory that had been produced but not yet sold to third parties at the end of the period. The

increase in intersegment eliminations was due to the timing of offshore liftings from the SeaRose in the Atlantic Region and Wenchang in the Asia Pacific Region.

Twelve Months

In 2011, the Corporate segment reported a loss of \$337 million compared with a loss of \$234 million in 2010 due to the same factors affecting the fourth quarter, in addition to an increase in administration expense of \$111 million compared with 2010 due to higher administration costs associated with financing projects and other initiatives.

Foreign Exchange Summary	Three months ended Dec. 31		Year ended Dec. 31	
	2011	2010	2011	2010
<i>(millions of dollars, except where indicated)</i>				
Gains (losses) on translation of U.S. dollar denominated long-term debt	\$ 45	\$ 73	\$ (47)	\$ 108
Gains (losses) on cross currency swaps	(9)	(12)	7	(18)
Gains (losses) on contribution receivable	(25)	(46)	34	(67)
Other gains (losses)	(26)	(91)	16	(72)
Foreign exchange gains (losses)	\$ (15)	\$ (76)	\$ 10	\$ (49)
U.S./Canadian dollar exchange rates:				
At beginning of period	U.S. \$0.963	U.S. \$0.971	U.S. \$1.005	U.S. \$0.956
At end of period	U.S. \$0.983	U.S. \$1.005	U.S. \$0.983	U.S. \$1.005

Included in other foreign exchange gains (losses) are realized and unrealized foreign exchange gains (losses) on working capital and intercompany financing.

The foreign exchange gains (losses) on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period.

Corporate Capital Expenditures

In 2011, Corporate capital expenditures of \$71 million were primarily for construction of a new building in Lloydminster and computer hardware and software.

Consolidated Income Taxes

During 2011, consolidated income tax expense was \$916 million compared with \$270 million in 2010. Cash taxes paid in 2011 were \$282 million compared with \$784 million in 2010, of which \$64 million related to instalments paid in

respect of 2010 net earnings, \$74 million related to 2011 earnings and \$144 million related to prior period payments. No further cash tax instalments will be required in respect of 2010 earnings.

6. Liquidity and Capital Resources

In 2011, Husky funded its capital programs, including acquisitions and dividend payments, through equity issuance, cash generated from operating activities and cash on hand. At December 31, 2011, Husky had total debt of \$3,911 million partially offset by cash on hand of \$1,841 million for \$2,070 million of net debt compared to \$3,935 million of net debt at December 31, 2010 consisting of \$4,187 million of total debt and \$252 million of cash on hand. At December 31, 2011, the Company had \$3.5 billion in unused committed credit facilities, \$110 million in

unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectus filed in Canada of \$300 million, which expired in January 2012, unused capacity under the November 2010 universal short form base shelf prospectus filed in Canada of \$1.4 billion, and unused capacity under the June 2011 U.S. base shelf prospectus of U.S. \$2.0 billion. The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. (Refer to Section 6.4).

Cash Flow Summary		Three months ended Dec. 31		Year ended Dec. 31	
		2011	2010	2011	2010
<i>(millions of dollars, except ratios)</i>					
Cash flow	- operating activities	\$ 1,035	\$ 494	\$ 5,092	\$ 2,222
	- financing activities	\$ 459	\$ 950	\$ 910	\$ 1,085
	- investing activities	\$ (1,431)	\$ (1,222)	\$ (4,420)	\$ (3,453)
Financial Ratios ⁽¹⁾					
Debt to capital employed <i>(percent)</i> ⁽²⁾				18.0	22.3
Debt to cash flow <i>(times)</i> ⁽³⁾⁽⁴⁾				0.8	1.4
Corporate reinvestment ratio <i>(percent)</i> ⁽³⁾⁽⁵⁾				98	134
Interest coverage ratios on long-term debt only ⁽³⁾⁽⁶⁾					
	Net earnings			14.5	6.2
	Cash flow			24.7	11.4
Interest coverage ratios on total debt ⁽³⁾⁽⁷⁾					
	Net earnings			14.1	6.0
	Cash flow			23.9	11.2

⁽¹⁾ The financial ratios constitute non-GAAP measures. Refer to Section 11.

⁽²⁾ Debt to capital employed is equal to long-term debt and long-term debt due within one year divided by shareholders' equity.

⁽³⁾ Calculated for the 12 months ended for the dates shown.

⁽⁴⁾ Debt to cash flow (times) is equal to long-term debt and long-term debt due within one year divided by cash flow from operations. Refer to Section 11 for a reconciliation of cash flow from operations to a GAAP measure.

⁽⁵⁾ Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations. Refer to Section 11 for a reconciliation of cash flow from operations to a GAAP measure.

⁽⁶⁾ Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow - operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.

⁽⁷⁾ Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow - operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized interest. Total debt includes short and long-term debt.

6.1 Operating Activities

Fourth Quarter

In the fourth quarter of 2011, cash generated from operating activities was \$1,035 million compared with \$494 million in the fourth quarter of 2010. Higher cash flow from operating activities was primarily due to higher production, higher crude oil prices in Upstream and higher realized margins in Canadian and U.S. Downstream.

Twelve Months

Cash generated from operating activities was \$5,092 million in 2011 compared with \$2,222 million in 2010. Higher cash flow from operating activities was primarily due to the same factors impacting the fourth quarter.

6.2 Financing Activities

Fourth Quarter

In the fourth quarter of 2011, cash generated from financing activities was \$459 million compared to \$950 million in 2010. The decrease in cash provided by financing activities was due to the common share issuances in the fourth quarter of 2010, partially offset by reduced cash dividends paid on common shares.

Twelve Months

Cash provided by financing activities was \$910 million in 2011 compared with \$1,085 million in 2010. The decrease in cash provided by financing activities was due to an increase in long-term debt issuances, net of repayments, partially offset by an increase in proceeds from common and preferred share issuances and the adoption of the stock dividend plan in 2011.

6.3 Investing Activities

Fourth Quarter

In the fourth quarter of 2011, cash used in investing activities amounted to \$1,431 million compared with \$1,222 million in the fourth quarter of 2010. Cash invested in both periods was primarily for expenditures on property, plant and equipment.

Twelve Months

Cash used in investing activities for 2011 was \$4.4 billion compared with \$3.5 billion in 2010. Cash invested in both periods was primarily for acquisitions and 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, cash on hand, the issuance of equity, the issuance of long-term debt and borrowings under committed and uncommitted credit facilities. The Company also maintains access to sufficient capital via debt markets commensurate with its balance sheet. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2011, working capital was \$2,054 million compared with \$1,181 million at December 31, 2010.

At December 31, 2011, Husky had unused long and short-term borrowing credit facilities totalling \$3.6 billion. A total of \$250 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

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

On December 21, 2009, Husky filed a debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enabled Husky to offer up to \$1.0 billion of medium-term notes in Canada until January 2012. As of December 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 \$3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 26, 2012 (the "Canadian Shelf Prospectus"). 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 under the Canadian 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 gross proceeds of approximately \$707 million. The common shares issued under the private placements were not issued under the Canadian Shelf Prospectus. 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 under the Canadian 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%.

On June 13, 2011, Husky filed a universal short form base shelf prospectus with the Alberta Securities Commission and the U.S. Securities and Exchange Commission that enables Husky to offer up to U.S. \$3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in the United States until July 13, 2013 (the "U.S. Shelf Prospectus").

On June 29, 2011, Husky issued 37 million common shares at a price of \$27.05 per share for total gross proceeds of approximately \$1.0 billion through a public offering, and a total of 7.4 million common shares at a price of \$27.05 per

share for total gross proceeds of \$200 million through a private placement to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. The Company received total gross proceeds of \$1.2 billion from this issuance. The public offering was completed under the

U.S. Shelf Prospectus and accompanying prospectus supplement in the United States and under the Canadian Shelf Prospectus and accompanying prospectus supplement in Canada.

Capital Structure

(millions of dollars)

	December 31, 2011	
	Outstanding	Available ⁽¹⁾
Total short-term and long-term debt	\$ 3,911	\$ 3,615
Common shares, preferred shares, retained earnings and other reserves	\$ 17,773	

⁽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.

	Within 1 year	After 1 year but not more than		Total
		5 years	More than 5 years	
Long-term debt and interest on fixed rate debt	631	1,982	3,030	5,643
Operating leases	108	288	119	515
Firm transportation agreements	187	767	3,291	4,245
Unconditional purchase obligations ⁽¹⁾	2,926	1,661	89	4,676
Lease rentals and exploration work agreements	77	764	519	1,360

⁽¹⁾ Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.

6.6 Off-Balance Sheet Arrangements

Husky does not have 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 a base shelf prospectus, which was filed with the Alberta Securities Commission and 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. \$122 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. At December 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.

On June 29, 2011, the Company issued 7.4 million common shares at a price of \$27.05 per share for total gross proceeds of \$200 million via a private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

All debt and equity issuance transactions with related parties have been 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.

In April 2011, Husky and TransAlta Cogeneration, L.P. ("TALCP"), which was the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster, sold the Meridian cogeneration facility to a related party. The consideration for Husky's share of the cogeneration facility was \$61 million, resulting in no net gain or loss on the transaction.

The Company continues to sell natural gas and purchase steam from the Meridian cogeneration facility and other

cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the three months and year ended December 31, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by the related party was \$27 million and \$108 million, respectively. For the three months and year ended December 31, 2011, the total value of obligated steam purchases from the Meridian and other cogeneration facilities owned by the related party was \$3 million and \$13 million, respectively.

7. Risks and Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 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 business operations are subject to numerous environmental laws and regulations regarding environmental, health and safety matters, including those relating to emissions to air, discharges to water and the storage and disposal of regulated materials. The nature of Husky's business is exposed to risks of liabilities under such laws and regulations due to the production, storage, use, transportation and disposal of materials that can cause contamination or personal injury if released into the environment.

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 cover such costs. Husky currently has a working interest in non-operated, inactive offshore deep water drilling operations in Canada and a deep water development drilling program in China.

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 and gas operations. Stricter regulation of offshore oil and gas operations has already been implemented by the United States with respect to operations in the Outer Continental Shelf, including 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 these areas. In the event that similar changes in environmental regulation occur with respect to Husky's operations in the Atlantic or Asia Pacific Regions, 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") is implementing regulations pertaining to greenhouse gas emissions, which could increase costs of doing business. In particular, the so-called 'Tailoring Rule' now requires sources emitting greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. The Tailoring Rule can also require the installation and operation of expensive pollution control technology as a part of any project that results in a

significant greenhouse gas emissions increase. The EPA has promulgated regulations requiring greenhouse gas emissions reporting from certain U.S. operations. The EPA is also required to issue greenhouse gas emission guidelines for existing refineries and new source performance standards for new refineries or modifications to existing refineries by November 10, 2012. These and other EPA regulations regarding greenhouse gas emissions are subject to legislative and judicial challenges, including current Congressional proposals to block or delay the EPA's authority to regulate greenhouse gas emissions. 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. Husky's operations may, however, be materially impacted by future application of these rules or 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 other risks. 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 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, equity 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 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 December 31, 2011, the Company had third party physical natural gas purchase and sale derivative 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 gain of \$23 million and loss of \$8 million have been recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three months and year ended December 31, 2011, respectively. Natural gas inventory held in storage relating to natural gas storage contracts is recorded at fair value. At December 31, 2011, the fair value of the inventory was \$121 million, resulting in an unrealized loss of \$17 million and \$3 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three months and year ended December 31, 2011, respectively.

At December 31, 2011, the Company had third party crude oil purchase and sale derivative contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accrued liabilities and the resulting unrealized loss of \$9 million and \$8 million have been recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three months and year ended December 31, 2011, respectively. The crude oil inventory held in storage is recorded at fair value. At December 31, 2011, the fair value of the inventory was \$16 million, resulting in an unrealized gain of \$1 million and \$2 million recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three months and year ended December 31, 2011, respectively.

The Company also enters into derivative 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 December 31, 2011, a loss related to these contracts of nil and \$7 million was recorded in purchases of crude oil and products in the Condensed Interim Consolidated Statements of Income for the three months and year ended December 31, 2011, respectively.

The Company enters into certain crude oil purchase and sale derivative 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 December 31, 2011, the Company had 1.1 mmbbls of purchase and sale contracts resulting in an unrealized loss of \$7 million and unrealized gain of \$4 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three months and year ended December 31, 2011, respectively. A portion of the related crude oil inventory is sold to third parties and measured at fair value. At December 31, 2011, the fair value of the inventory was \$147 million, resulting in an unrealized loss of \$1 million and unrealized gain of less than \$1 million recorded in other expenses in the Condensed Interim Consolidated Statements of Income for the three months and year ended December 31, 2011, respectively.

During 2011, the Company entered into third party commodity swaps based on the price of butane and crude oil. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized loss of less than \$1 million and gain of less than \$1 million for the three months and year ended December 31, 2011 has been recorded in other expenses in the Condensed Interim Consolidated Statements of Income.

7.6 Interest Rate Risk Management

The Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates. These interest rate swap arrangements were sold and derecognized during the fourth quarter of 2011. Accordingly, the accrued gains on these interest rate swaps will be amortized over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated.

During the three months and year ended December 31, 2011, these swaps resulted in an addition to finance expenses of \$4 million and a reduction of \$13 million,

respectively. The amortization of terminated interest rate swaps resulted in additional finance expenses of \$5 million and \$8 million for the three months and year ended December 31, 2011, respectively.

7.7 Foreign Currency Risk Management

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

- 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 \$1.19 to \$89 million at 5.65% 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.
- U.S. \$150 million at 6.25% swapped at \$1.41 to \$211 million at 7.41% until June 15, 2012.

At December 31, 2011, the cost of a U.S. dollar in Canadian currency was \$1.0170.

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 finance expense. At December 31, 2011, 82% or \$3.1 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 73% when the cross currency swaps are considered.

As at December 31, 2011, the Company has designated U.S. \$1.3 billion 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 2011, the unrealized foreign exchange arising from the translation of the debt was a gain of \$19 million, net of

tax of \$3 million and a loss of \$18 million, net of tax of \$3 million, which was recorded in Other Comprehensive Income for the three months and year ended December 31, 2011, respectively.

Including cross currency swaps and the debt that has been designated as a hedge of a net investment, 27% 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 December 31, 2011, Husky's share of this receivable was U.S. \$1.1 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 December 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 freestanding derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the 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.

8. Critical Accounting Estimates

Certain Husky accounting policies require 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 net earnings 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 net 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 and hedge accounting to manage market risk. 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 wells, 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 may result in changes to the ARO.

Employee Future Benefits

The determination of the cost of the post-retirement health and dental care plan and the 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 is 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 whether the loss can be reasonably estimated. When a loss is determined it is charged to net earnings. Husky must continually monitor known and potential contingent matters and make appropriate provisions by charges to net 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 acquisition 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 net earnings. Contingent consideration associated with a business combination is based on the satisfaction of future conditions which requires Husky to make certain judgments of the probability of such conditions being fulfilled to estimate the contingent consideration to be paid in future years. The actual consideration paid may differ materially from amounts estimated in the provision recorded.

9. Recent Accounting Standards

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 three months and year ended December 31, 2011 and comparative periods are reported under IFRS while selected historical data continues to be reported under previous Canadian GAAP (Refer to Note 16 of the Condensed Interim Consolidated Financial

Statements for the Company’s assessment of impacts of the transition to IFRS).

Presentation of Financial Statements

In June 2011, the IASB issued IAS 1, “Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements.” The amendments stipulate the presentation of net earnings and Other Comprehensive Income (“OCI”) and also require the Company to group items within OCI

based on whether the items may be subsequently reclassified to net earnings. Amendments to IAS 1 were effective for the Company beginning on January 1, 2012 with required retrospective application and early adoption permitted.

The Company retrospectively adopted the amendments on January 1, 2012. The adoption of the amendments to this standard did not have a material impact on the Company's financial statements.

Consolidated Financial Statements

In May 2011, the IASB published IFRS 10, "Consolidated Financial Statements," which provides a single model to be applied in the assessment of control for all entities in which the Company has an investment including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a linkage between the ability to direct activities and the variability of returns. IFRS 10 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 10 in its financial statements for the annual period beginning on January 1, 2013. The adoption of the standard is not expected to have a significant impact to the Company's financial statements.

Joint Arrangements

In May 2011, the IASB published IFRS 11, "Joint Arrangements," whereby joint arrangements are classified as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation, while parties to a joint venture have rights to the net assets of the venture. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses are included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the existing IFRS standard, the Company has the option to account for any interests it has in joint arrangements using proportionate consolidation or equity accounting. IFRS 11 is effective for the Company on January 1, 2013 with retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 11 in its financial statements for the annual period

beginning January 1, 2013 and is currently reviewing the classification of its joint arrangements. The extent of the impact of adoption of IFRS 11 has not yet been determined.

Disclosure of Interests in Other Entities

In May 2011, the IASB published IFRS 12, "Disclosure of Interests in Other Entities," which contains new disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of and risks associated with the Company's interests in other entities and the effects of those interests on the Company's financial statements. IFRS 12 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 12 in its financial statements for the annual period beginning on January 1, 2013. It is expected that IFRS 12 will increase the current level of disclosure related to the Company's interests in other entities upon adoption.

Investments in Associates and Joint Ventures

In May 2011, the IASB issued amendments to IAS 28, "Investments in Associates and Joint Ventures," which provides additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to remeasure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. Amendments to IAS 28 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt these amendments in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect the amendments to IAS 28 to have a material impact on the financial statements.

Fair Value Measurement

In May 2011, the IASB published IFRS 13, "Fair Value Measurement," which provides a single source of fair value measurement guidance and replaces fair value measurement guidance contained in individual IFRSs. The

standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements and for recurring valuations that are subject to measurement uncertainty, the effect of those measurements on the financial statements. IFRS 13 is effective for the Company on January 1, 2013 with required prospective application and early adoption permitted. The Company intends to adopt IFRS 13 prospectively in its financial statements for the annual period beginning on January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19, "Employee Benefits" to eliminate the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans.

Amendments to IAS 19 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted.

The Company intends to retrospectively adopt these amendments in its financial statements for the annual period beginning on January 1, 2013. The adoption of the amended standard is not expected to have a material impact on the Company's financial statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7 "Financial Instruments: Disclosures" and IAS 32, "Financial

Instruments: Presentation" to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 are effective for the Company on January 1, 2013 with required retrospective application and early adoption is permitted. Amendments to IAS 32 are effective for the Company on January 1, 2014 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the IFRS 7 amendments in its financial statements for the annual period beginning on January 1, 2013 and the IAS 32 amendments for the annual period beginning January 1, 2014. The adoption of these amended standards is not expected to have a material impact on the Company's financial statements.

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, the 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 OCI. IFRS 9 is effective for the Company on January 1, 2015 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2015. The adoption of the standard is not expected to have a significant impact to the Company's financial statements.

10. Outstanding Share Data

<i>(in thousands)</i>	January 31 2012	December 31 2011
Issued and outstanding		
Number of common shares	965,758	957,537
Number of stock options	33,187	33,337
Number of stock options exercisable	18,392	18,486
Number of preferred shares	12,000	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, Note 24 of the 2010 Consolidated Financial Statements and the 2010 Annual Information Form 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 December 31, 2011 are compared with results for the three months ended December 31, 2010 and the results for the year ended December 31, 2011 are compared with results for the year ended December 31, 2010. Discussions with respect to Husky's financial position as at December 31 2011 are compared with its financial position at December 31, 2010. Amounts presented within this interim report are unaudited.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in this Interim Report 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 non-GAAP Measurements

Husky uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this interim report are: cash flow from operations, adjusted net earnings, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt and interest coverage on total debt. None of these measurements are used to enhance the Company's reported financial performance or position. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. With the exception of cash flow from operations and adjusted net earnings, there are no comparable measures in accordance with IFRS. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application.

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, amortization, and impairment, deferred taxes, foreign exchange and other non-cash items.

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

		Three months ended Dec. 31		Year ended Dec. 31	
		2011	2010	2011	2010
<i>(millions of dollars)</i>					
Non-GAAP	Cash flow from operations	\$ 1,197	\$ 685	\$ 5,198	\$ 3,072
	Settlement of asset retirement obligations	(37)	(26)	(105)	(60)
	Income taxes paid	(40)	(36)	(282)	(784)
	Interest received	8	-	12	1
	Change in non-cash working capital	(93)	(129)	269	(7)
GAAP	Cash flow – operating activities	\$ 1,035	\$ 494	\$ 5,092	\$ 2,222

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.

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

		Three months ended Dec. 31		Year ended Dec. 31	
		2011	2010	2011	2010
<i>(millions of dollars)</i>					
GAAP	Net earnings	\$ 408	\$ 139	\$ 2,224	\$ 947
	Foreign exchange	13	66	(6)	45
	Financial instruments	3	15	6	24
	Stock-based compensation	4	3	(1)	(10)
	Inventory write-downs	1	2	2	23
	Impairment of property, plant and equipment	52	-	52	-
Non-GAAP	Adjusted net earnings	\$ 481	\$ 225	\$ 2,277	\$ 1,029

Cautionary Note Required by National Instrument 51-101

The Company uses the terms barrels of oil equivalent (“boe”), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe may be

misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

Abbreviations

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

Terms

<i>Bitumen</i>	<i>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</i>
<i>Capital Employed</i>	<i>Short and long-term debt and shareholders' equity</i>
<i>Capital Expenditures</i>	<i>Includes capitalized administrative expenses but does not include proceeds, other assets or capitalized interest</i>
<i>Capital Program</i>	<i>Capital expenditures not including capitalized administrative expenses or capitalized interest</i>
<i>Cash Flow from Operations</i>	<i>Net earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid and change in non-cash working capital</i>
<i>Coal Bed Methane</i>	<i>Methane (CH₄), the principal component of natural gas, is adsorbed in the pores of coal seams</i>
<i>Corporate Reinvestment Ratio</i>	<i>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</i>
<i>Dated Brent</i>	<i>Price are dated less than 15 days prior to loading for delivery</i>
<i>Debt to Capital Employed</i>	<i>Total debt divided by total debt and shareholders' equity</i>
<i>Debt to Cash Flow</i>	<i>Total debt divided by cash flow from operations calculated on a 12-month trailing basis</i>
<i>Delineation Well</i>	<i>A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir</i>
<i>Diluent</i>	<i>A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline</i>
<i>Equity</i>	<i>Common shares, preferred shares, retained earnings and other reserves</i>
<i>Feedstock</i>	<i>Raw materials which are processed into petroleum products</i>
<i>Front End Engineering Design</i>	<i>Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics</i>
<i>Gross/Net Acres/Wells</i>	<i>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</i>
<i>Gross Reserves/Production</i>	<i>A company's working interest share of reserves/production before deduction of royalties</i>
<i>Hectare</i>	<i>One hectare is equal to 2.47 acres</i>
<i>Near-month Prices</i>	<i>Prices quoted for contracts for settlement during the next month</i>
<i>NOVA Inventory Transfer</i>	<i>Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline</i>
<i>Return on Capital Employed</i>	<i>Net earnings plus after tax finance expense calculated on a 12-month trailing basis divided by average capital employed</i>
<i>Return on Shareholders' Equity</i>	<i>Net earnings calculated on a 12-month trailing basis divided by average shareholders' equity</i>
<i>Stratigraphic Well</i>	<i>A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production</i>
<i>Synthetic Oil</i>	<i>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</i>
<i>Three Dimensional (3-D) Seismic</i>	<i>Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line</i>
<i>Total Debt</i>	<i>Long-term debt including current portion and bank operating loans</i>
<i>Turnaround</i>	<i>Scheduled performance of plant or facility maintenance</i>

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," "is targeting," "estimated," "intend," "plan," "projection," "could," "aim," "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 and growth strategies; the timetable of project execution, including planned first production at the Company's Liwan Gas Project; planned timing of regulatory submissions and expected first gas at the Company's Madura Straits block; timing of well completions and expected effect of the pilot program at the Company's West White Rose field; development and drilling plans at the Company's North Amethyst and White Rose fields; the anticipated timing of awarding Pre-FEED and FEED contracts at the Company's West White Rose field; project schedule and anticipated timing of first production at Phase I of the Company's Sunrise Energy Project; the expected timing for the completion of the full drilling program at the Sunrise Energy Project; expected timing of completion of FEED for the next development stage of the Sunrise Energy Project; the expected timing of equipping, completion and production at the Company's McMullen property; 2012 exploration plans at the Company's Saleski property; the expected timing of first oil at the Company's Pikes Peak South heavy oil thermal project; the expected timing of first oil at the Company's Paradise Hill heavy oil project; 2012 drilling plans in the Company's heavy oil area; the expected timing of commissioning of the CO₂ capture and liquefaction plant at the Company's Lloydminster Ethanol Plant, and planned use of CO₂ from the plant; 2012 drilling plans at the Company's Ansell property; 2012 drilling and exploration plans at the Company's Kaybob property; 2012 drilling plans at the Company's Oungre Bakken project; expected timing of production from the Company's Redwater Viking project; 2012 drilling plans at the Company's Redwater and Saskatchewan Viking projects; 2012 drilling plans at the Company's Shaunavon oil resource play; anticipated results of pilot wells at the Company's Rainbow Muskwa project; 2012

well completion plans and other activities at the Company's Rainbow Muskwa project; timing and expected outcome of the pilot drilling program at the Company's Canol shale project; the expected timing and outcome of construction of a 300,000 barrel tank at the Hardisty terminal; the expected timing and outcome of operations of construction of a kerosene hydrotreater at the Lima refinery; the timing, duration and expected impact of the planned offstation of the SeaRose FPSO; the timing, duration and expected impact of dockside maintenance for the Terra Nova FPSO; the timing of planned turnarounds at the Upgrader, Lloydminster Refinery and Toledo Refinery; the timing and expected impact of planned outages at the Lima Refinery; and the timing of adoption and anticipated impact of recent accounting standards.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this interim report 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.