MANAGEMENT'S DISCUSSION AND ANALYSIS

May 6, 2013

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary *($ millions, except where indicated)*	**Mar.31 2013**	Dec. 31 2012	Sept. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011	Sept. 30 2011	Jun. 30 2011
Production *(mboe/day)*	**321.3**	319.3	285.0	281.9	319.9	318.9	309.1	311.6
Gross revenues[(1)]	**5,807**	5,945	5,451	5,748	5,984	5,888	6,079	6,043
Net earnings	**535**	474	526	431	591	408	521	669
Per share – Basic	**0.54**	0.48	0.53	0.44	0.61	0.42	0.55	0.73
Per share – Diluted	**0.54**	0.48	0.53	0.43	0.60	0.42	0.53	0.71
Cash flow from operations[(2)]	**1,283**	1,414	1,271	1,153	1,172	1,197	1,326	1,511
Per share – Basic	**1.31**	1.44	1.29	1.18	1.21	1.25	1.40	1.68
Per share – Diluted	**1.30**	1.44	1.29	1.17	1.20	1.24	1.39	1.67

(1) *Gross revenues have been recast to reflect a change in presentation for trading activities. Refer to Note 3 of the 2012 Consolidated Financial Statements.*
(2) *Cash flow from operations is a non-GAAP measure. Refer to Section 11 for a reconciliation to the GAAP measure.*

Performance

- First quarter production of 321.3 mboe/day was comparable to the same period in 2012 but with increased oil weighting:
  - Increased crude oil production in Western Canada from heavy oil thermal projects; and
  - Decreased natural gas production due to natural reservoir declines and limited re-investment as capital is being directed to higher return oil and liquids-rich gas developments.

- Net earnings were $535 million in the first quarter of 2013 compared to $591 million in the first quarter of 2012, reflecting the benefit of Husky's integrated operations:
  - Lower West Texas Intermediate ("WTI") and Brent crude oil prices and high differentials on heavy crude oil production in Western Canada were partially offset by higher U.S. Refining throughput and market crack spreads and increased heavy crude oil production from new thermal projects;
  - Increased margins at the Company's upgrading facility in Western Canada and at the refinery in Toledo, Ohio where heavy crude oil is consumed as upgrading and refinery feedstock; and
  - Utilization of the Company's infrastructure to transport crude oil from Canada to the United States resulted in increased Infrastructure and Marketing earnings.

- Cash flow from operations in the first quarter of 2013 increased compared to the first quarter of 2012 mainly due to higher realized margins in Downstream and stronger Infrastructure and Marketing earnings, partially offset by lower realized commodity prices in Upstream Exploration and Production**.**

Key Projects

- At the Liwan Gas Project, the central platform topsides were loaded out for transport to the South China Sea. The project is progressing on track and was approximately 85% complete at the end of the first quarter of 2013.
- At the Sunrise Energy Project, work continues on the Central Processing Facility (“CPF”) and field facilities. The project is approximately 65% complete and remains on track for first production in 2014.
- At the South White Rose Extension, drilling commenced in February 2013 on a series of six planned wells which will be developed through a subsea tieback to the SeaRose floating, production, storage and offloading vessel ("FPSO").
- Average production levels of approximately 12,400 bbls/day at Pikes Peak South and 5,400 bbls/day at Paradise Hill heavy oil thermal projects were achieved in the first quarter of 2013.
- At the 3,500 bbls/day Sandall heavy oil thermal development project, construction is approximately 55% complete and initial drilling has commenced. This project is scheduled for first production in 2014. Design and initial site work continues on the 10,000 bbls/day heavy oil Rush Lake thermal development project.
- Resource play development progressed in Western Canada with 45 oil wells (gross) and 10 liquids-rich natural gas wells (gross) drilled in the first quarter of 2013 and 24 and 12 wells (gross) completed, respectively.
- The development of the BD field on the Madura Strait Block is progressing with the evaluation of tender bids for an FPSO and engineering, procurement, installation and commissioning ("EPIC") contracts ongoing. The development plan for a combined MDA and MBH development project was approved by the regulator in January 2013.
- The new 20 mbbls/day Kerosene Hydrotreater was brought on-line in mid-April at the Lima Refinery in Ohio. The hydrotreater gives the refinery greater flexibility to swing between on-road diesel and jet fuel production to take advantage of market conditions while also increasing distillate capacity.
- The Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo Ohio, Refinery is now operational with the start up completed in the quarter.
- Construction began on a multi-year Hardisty terminal expansion project which will add two 300,000 barrel storage tanks and increase connectivity to the Keystone Pipeline.

Financial

- Dividends on common shares of $295 million for the fourth quarter of 2012 were declared during the first quarter of 2013, of which $294 million and $1 million were paid in cash and common shares, respectively, on April 1, 2013.

2. Business Environment

Average Benchmarks		Three months ended Mar. 31 2013	Dec. 31 2012	Sept. 30 2012	Jun. 30 2012	Mar. 31 2012
WTI crude oil[(1)]	*(U.S. $/bbl)*	**94.37**	88.18	92.22	93.49	102.93
Brent crude oil[(2)]	*(U.S. $/bbl)*	**112.55**	110.00	109.48	109.29	118.49
Canadian light crude 0.3% sulphur	*($/bbl)*	**88.42**	84.43	84.89	84.37	92.70
Western Canada Select[(3)]	*(U.S. $/bbl)*	**62.41**	70.07	70.49	70.63	81.51
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**46.44**	59.55	61.91	60.12	69.95
NYMEX natural gas[(4)]	*(U.S. $/mmbtu)*	**3.34**	3.40	2.81	2.21	2.74
NIT natural gas	*($/GJ)*	**2.92**	2.90	2.08	1.74	2.39
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**32.18**	18.29	21.94	23.58	21.99
New York Harbour 3:2:1 crack spread	*(U.S. $/bbl)*	**30.61**	35.06	34.77	29.21	26.31
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**26.87**	28.00	35.18	27.85	19.35
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.991**	1.009	1.005	0.990	0.999
Canadian $ Equivalents						
WTI crude oil[(5)]	*($/bbl)*	**95.23**	87.39	91.76	94.43	103.03
Brent crude oil[(5)]	*($/bbl)*	**113.57**	109.02	108.94	110.39	118.61
WTI/Lloyd crude blend differential[(5)]	*($/bbl)*	**32.47**	18.13	21.83	23.82	22.01
NYMEX natural gas[(5)]	*($/mmbtu)*	**3.37**	3.37	2.79	2.23	2.74

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

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

(3) *Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils and is traded at Hardisty, Alberta. Quoted prices are based on the average price during the month.*

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

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

The price Husky Energy Inc. ("Husky" or "the Company") receives for production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada, while the majority of the Company's production in the Atlantic and Asia Pacific regions is referenced to the price of Brent. The price of WTI averaged U.S. $94.37/bbl in the first quarter of 2013 compared with U.S. $102.93/bbl in the first quarter of 2012. The price of Brent averaged U.S. $112.55/bbl in the first quarter of 2013 compared with U.S. $118.49/bbl in the first quarter of 2012.

In the first quarter of 2013, the price of WTI in both U.S. and Canadian dollars decreased by 8% when compared with the same period in 2012.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In the first quarter of 2013, 53% of Husky's crude oil production was heavy oil or bitumen compared with 48% in the first quarter of 2012 due to increased production from heavy oil thermal projects. The light/heavy crude oil differential averaged U.S. $32.18/bbl or 34% of WTI in the first quarter of 2013 compared with U.S. $21.99/bbl or 21% of WTI in the first quarter of 2012.

During the first quarter of 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.34/mmbtu compared with U.S. $2.74/mmbtu in the first quarter of 2012, an increase of 22%.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and International Upstream operations.

In the first quarter of 2013, the Canadian dollar averaged U.S. $0.991, weakening by 1% compared with U.S. $0.999 during the first quarter of 2012.

Refining Crack Spreads

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

During the first quarter of 2013, the Chicago 3:2:1 crack spread averaged U.S. $26.87/bbl compared with U.S. $19.35/bbl in the first quarter of 2012. During the first quarter of 2013, the New York Harbour 3:2:1 crack spread averaged U.S. $30.61/bbl compared with U.S. $26.31/bbl in the first quarter of 2012.

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. Husky's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Sensitivity Analysis

The following table is indicative of the relative annualized effect on earnings before income taxes and net earnings from changes in certain key variables in the first quarter of 2013. The table below reflects what the effect would have been on the financial results for the first quarter of 2013 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the first quarter of 2013. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	2013 First Quarter Average	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	94.37	*U.S. $1.00/bbl*	72	0.07	53	0.05
NYMEX benchmark natural gas price[5]	3.34	*U.S. $0.20/mmbtu*	16	0.02	12	0.01
WTI/Lloyd crude blend differential[6]	32.18	*U.S. $1.00/bbl*	(18)	(0.02)	(14)	(0.01)
Canadian light oil margins	0.048	*Cdn $0.005/litre*	15	0.02	11	0.01
Asphalt margins	41.67	*Cdn $1.00/bbl*	8	0.01	6	0.01
New York Harbour 3:2:1 crack spread	30.61	*U.S. $1.00/bbl*	54	0.06	34	0.03
Exchange rate (U.S. $ per Cdn $)[3][7]	0.991	*U.S. $0.01*	(55)	(0.06)	(40)	(0.04)

(1) Excludes mark to market accounting impacts.
(2) Based on 982.7 million common shares outstanding as of March 31, 2013.
(3) Does not include gains or losses on inventory.
(4) Includes impacts related to Brent based production.
(5) Includes impact of natural gas consumption.
(6) Excludes impact on asphalt operations.
(7) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.

3. Strategic Plan

Husky's strategy is to maintain and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward thermal developments and resource plays, while advancing its three major growth pillars in the Asia Pacific Region, the Oil Sands and in the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

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

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

4. Key Growth Highlights

The 2013 Capital Program builds on the momentum achieved over the past two years with respect to repositioning the Heavy Oil and Western Canada foundation by accelerating near-term production growth and advancing Husky's three major growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

4.1 Upstream

Western Canada (Excluding Heavy Oil and Oil Sands)

Oil Resource Plays

In the first quarter of 2013, a total of 45 horizontal wells (gross) were drilled and 22 horizontal wells (gross) and two vertical wells (gross) were completed across the oil resource project portfolio.

Oil Resource Plays - Drilling and Completion Activity[1]		Three months ended March 31,	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	5	3
Lower Shaunavon	S.W. Saskatchewan	2	1
Viking [2]	Alberta and S.W. Saskatchewan	28	12
N.Cardium	Wapiti, Alberta	4	4
Muskwa	Rainbow, Northern Alberta	6	2
Canol Shale	Northwest Territories	-	2
Total Gross		45	24
Total Net		44	23

(1) *Excludes service/stratigraphic test wells for evaluation purposes. All activity was horizontal except Slater River N.W.T. vertical wells.*

(2) *Viking is comprised of project activity at Redwater in central Alberta, Alliance in southeast Alberta and drilling in southwest Saskatchewan.*

The winter 2013 program at the Slater River Canol Shale project in the Northwest Territories was completed in the first quarter of 2013. Two vertical wells that were drilled in 2012 were completed and tested, the baseline groundwater study was completed and approximately 19 kilometres of a 40-kilometre all-season access road was constructed. Operations are planned to recommence in the third quarter of 2013.

At Rainbow Muskwa, drilling and completion practices are continuing to be optimized based upon the results from previous wells and more specific targeting within the Muskwa reservoir.

Liquids-Rich Natural Gas Resource Plays

In the first quarter of 2013, four liquids-rich horizontal natural gas wells (gross) and six vertical multi-zone appraisal wells (gross) were drilled and 12 wells (gross) were completed at the Ansell Multi-Zone play.

Drilling activity also continued at Kaybob in the Duvernay play in the first quarter of 2013.

Liquids-Rich Natural Gas Plays - Drilling and Completion Activity[1]		Three months ended March 31,	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	10	12
Duvernay	Kaybob, Alberta	-	-
Montney	Kakwa, Alberta	-	-
Total Gross		10	12
Total Net		10	12

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*

Alkaline Surfactant Polymer Floods

Construction was completed on the Fosterton, Saskatchewan Alkaline Surfactant Polymer ("ASP") facility in late 2012. Chemical injection continued in the first quarter of 2013.

Conventional Oil and Gas

Approximately 80 wells were drilled and 60 wells were completed in the first quarter of 2013 in the conventional oil and gas portfolio.

Heavy Oil

Average production levels of approximately 12,400 bbls/day at Pikes Peak South and 5,400 bbls/day at Paradise Hill heavy oil thermal projects were achieved during the first quarter of 2013.

Construction is approximately 55% complete at the 3,500 bbls/day Sandall thermal development project and initial drilling has commenced. First production is scheduled in 2014.

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

Horizontal development progressed in the first quarter of 2013 with 38 wells drilled out of the 140 well program for 2013 compared with 35 wells drilled in the first quarter of 2012.

Fifty-five Cold Heavy Oil Production with Sand ("CHOPS") wells were drilled during the first quarter of 2013 compared with 69 CHOPS wells drilled in the first quarter of 2012. In 2013, 200 CHOPS wells are planned.

Asia Pacific Region

China

Block 29/26

The Liwan Gas Project development on Block 29/26 in the South China Sea is now approximately 85% complete and remains on track to achieve planned first production in late 2013/early 2014.

One further upper completion in the Liwan 3-1 gas field was installed and flow tested at the expected production rate bringing the total of fully ready production wells to eight. The upper completion on the final Liwan 3-1 production well is expected to be completed in the second quarter of 2013. The deepwater construction season commenced with the mobilization of vessels in March to coincide with the start of the seasonal calm water period of the South China Sea. Fabrication of the platform topsides is 99% complete, the load out of the topsides onto a barge was completed in mid-April and the transport to the central platform final location is in progress. Construction of the onshore gas plant is more than 85% complete. All 10 spherical liquids storage tanks are in place and the construction of pipe racks for transporting gas through the site is nearing completion.

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

Indonesia

Two shallow water gas developments in the Madura Strait are being progressed.

The development project for the BD field on the Madura Strait Block is progressing. Evaluation of tender bids for the FPSO and EPIC contracts are in progress. The development plan for a combined MDA and MBH development project was approved by the regulator in January 2013 and tender documents for the development work on this combined field development are in preparation. First gas from the Madura Strait Block is anticipated for the 2015 time frame.

Four new gas discoveries made offshore Indonesia in 2012 continue to be evaluated for commercial development.

Taiwan

Husky is planning to carry out a 2D-seismic survey program by the end of 2013 on the recently acquired exploration block offshore Taiwan in the South China Sea.

Oil Sands

Sunrise Energy Project

Phase 1 of the Sunrise Energy Project remains on track for first production in 2014 and is approximately 65% complete.

The CPF is now more than half complete with critical equipment delivered and all critical modules for Plant 1A fabricated and delivered to the project site. Construction of field facilities is approaching 90% complete and all well pads and pipelines are on target for completion in the second half of 2013. To date, approximately two-thirds of the project's total cost estimate has been spent.

Development work continues on the next phase of the Sunrise Energy Project with Design Basis Memorandum (“DBM”) expected to finish in the second quarter of 2013.

Saleski

A regulatory application for a 3,000 bbls/day bitumen carbonate pilot was filed in early May 2013.

McMullen

During the first quarter of 2013, seven evaluation wells and eight slant development wells were drilled in the cold production development project and 16 slant wells that were drilled in late 2012 were placed on production. At the air injection pilot, on-going testing and monitoring of the horizontal producer is continuing as planned. Production from an additional two horizontal wells at the pilot is anticipated later in the year.

Atlantic Region

White Rose Field and Satellite Extensions

Drilling commenced on a fourth water injection well at the North Amethyst oil field which is planned to be in service in the third quarter of 2013. An application to develop the deeper Hibernia level formation at North Amethyst is undergoing regulatory review.

Development drilling commenced in February 2013 on the first gas injection well at the South White Rose Extension. The field will be developed through a subsea tieback to the SeaRose FPSO with anticipated first production in 2014. A development plan amendment for the project is currently undergoing regulatory review.

Front End Engineering Design (“FEED”) work for the West White Rose Extension was completed during the first quarter of 2013. The development application is currently being prepared.

Production continued to ramp up at the Terra Nova field with a third drill centre brought back into operation in late March.

Atlantic Exploration

The partner-operated Harpoon exploration well located near the Mizzen discovery in the Flemish Pass was spud in the first week of April 2013. Drilling is scheduled to continue in the second quarter. Husky holds a 35% working interest in the well.

4.2 Downstream

Lima, Ohio Refinery

The Lima, Ohio Refinery continues to progress reliability and profitability improvement projects. The new 20 mbbls/day Kerosene Hydrotreater was brought on-line in mid-April. The hydrotreater gives the refinery greater flexibility to swing between on-road diesel and jet fuel production to take advantage of market conditions while also increasing distillate capacity.

BP-Husky Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo, Ohio Refinery is now operational with the start up completed in the first quarter of 2013. The refinery continues to advance a multi-year program to improve feedstock flexibility, operational integrity and plant performance while reducing operating costs and environmental impacts.

5. Results of Operations

5.1 Upstream

Total First Quarter Upstream Earnings 2013 - $255 million, 2012 - $511 million

Total Upstream net earnings include results from both the Exploration and Production operations and the Infrastructure and Marketing operations. Net earnings on a combined basis reflect the impact of declines in crude oil prices together with wider differentials for heavy crude oil in the first quarter of 2013 compared with the same period in 2012 partially offset by higher marketing margins realized as a result of capturing location differentials by utilizing the Company's infrastructure to move crude oil from Canada to the United States. Additional margins were also realized in Downstream as a result of the Company's integrated operations.

Exploration and Production

Exploration and Production Earnings Summary	Three months ended March 31,	
($ millions)	**2013**	2012
Gross revenues	**1,645**	1,971
Royalties	**(204)**	(219)
Net revenues	**1,441**	1,752
Purchases, operating, transportation and administration expenses	**559**	516
Depletion, depreciation and amortization	**562**	529
Exploration and evaluation expenses	**88**	75
Other expenses	**70**	18
Income taxes	**41**	159
Net earnings	**121**	455

Exploration and Production net earnings in the first quarter of 2013 decreased by $334 million compared with the first quarter of 2012 primarily due to lower realized crude oil prices, partially offset by increased production from heavy oil thermal projects. Other expenses include the elimination of internal profit included in inventory at the end of the quarter.

Production was 321.3 mboe/day in the first quarter of 2013 compared with 319.9 mboe/day in the first quarter of 2012 with an increased crude oil weighting. Crude oil production increased in Western Canada due to the continued success at the Pikes Peak South and Paradise Hill heavy oil thermal projects, partially offset by natural reservoir declines in natural gas properties as capital investment is being directed to higher return oil and liquids-rich gas developments.

The average realized price for crude oil, NGL and bitumen in the first quarter of 2013 was $68.32/bbl compared with $87.11/bbl during the same period in 2012, a 22% decrease, due to lower commodity market prices combined with wider Western Canada differentials. Realized natural gas prices averaged $3.08/mcf in the first quarter of 2013 compared with $2.64/mcf in the same period in 2012, an increase of 17%.

Average Sales Prices Realized	Three months ended March 31, 2013	2012
Crude oil and NGL *($/bbl)*		
Light crude oil & NGL	**103.59**	111.53
Medium crude oil	**61.74**	78.63
Heavy crude oil	**45.67**	68.93
Bitumen	**43.12**	65.83
Total average	**68.32**	87.11
Natural gas average *($/mcf)*	**3.08**	2.64
Total average *($/boe)*	**54.43**	65.26

The price realized for Western Canada crude oil was the result of decreases in WTI combined with wider Western Canada and heavy oil and bitumen differentials. The significant premium to WTI realized for offshore production reflects Brent prices.

Daily Gross Production	Three months ended March 31, 2013	2012
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**30.7**	30.5
Medium crude oil	**23.0**	24.9
Heavy crude oil	**74.4**	76.2
Bitumen[(1)]	**47.9**	29.6
	176.0	161.2
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**43.1**	45.3
Terra Nova – light crude oil	**4.8**	6.8
	47.9	52.1
China		
Wenchang – light crude oil & NGL	**7.8**	8.6
	231.7	221.9
Natural gas *(mmcf/day)*	**537.3**	588.3
Total *(mboe/day)*	**321.3**	319.9

(1) Bitumen production includes heavy oil thermal average daily gross production which receives a higher price than bitumen production.

Crude Oil and NGL Production

Crude oil and NGL production in the first quarter of 2013 increased by 9.8 mbbls/day or 4% compared with the same period in 2012 due to the continued success in Western Canada at the Pikes Peak South and Paradise Hill heavy oil thermal projects partially offset by lower production in the Atlantic Region at Terra Nova, where volumes continue to ramp-up following the turnaround completed in late 2012.

Natural Gas Production

Natural gas production in the first quarter of 2013 decreased by 51.0 mmcf/day or 9% compared with the first quarter of 2012 due to natural reservoir declines in mature properties as capital investment is being directed to higher return oil and liquids-rich natural gas developments.

2013 Production Guidance

The following table shows actual daily production for the three months ended March 31, 2013 and the year ended December 31, 2012, as well as the production guidance for 2013.

		Actual Production	
	2013 Guidance	Three months ended March 31, 2013	Year ended December 31, 2012
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	85 – 90	86	72
Medium crude oil	25 – 30	23	24
Heavy crude oil & bitumen	110 – 120	122	113
	220 – 240	231	209
Natural gas *(mmcf/day)*	540 – 580	537	554
Total (mboe/day)	310 – 330	321	302

Royalties

In the first quarter of 2013, royalty rates as a percentage of gross revenues averaged 13% compared with 12% in the same period in 2012. Royalty rates in Western Canada averaged 12% in the first quarter of 2013 compared with 9% in the same period in 2012 primarily due to a royalty credit adjustment received in the first quarter of 2012. Royalty rates for the Atlantic Region averaged 13% in the first quarter of 2013 down from 14% in the first quarter of 2012. Royalty rates in the Asia Pacific Region averaged 26% in the first quarter of 2013 compared with 24% in the same period in 2012 primarily due to a windfall gain tax adjustment which impacted royalties in first quarter of 2012.

Operating Costs

	Three months ended March 31,	
($ millions)	2013	2012
Western Canada	423	389
Atlantic Region	43	55
Asia Pacific	7	6
Total	473	450
Unit operating costs *($/boe)*	15.29	14.56

Total operating costs in the first quarter of 2013 were $473 million compared with $450 million in the same period in 2012. Total unit operating costs in the first quarter of 2013 averaged $15.29/boe compared with $14.56/boe for the same period in 2012.

Operating costs in Western Canada averaged $16.39/boe in the first quarter of 2013 compared with $15.37/boe in the same period in 2012 primarily due to increased natural gas prices and higher energy consumption driven by increasing thermal production.

Operating costs in the Atlantic Region averaged $9.98/boe in the first quarter of 2013 compared with $11.63/boe in the same period in 2012. The decrease in operating costs was attributable to turnaround costs in the first quarter of 2012.

Operating costs in the Asia Pacific Region averaged $9.97/boe in the first quarter of 2013 compared with $7.85/boe in the same period in 2012. The increase was due to higher maintenance and servicing costs combined with lower production compared with the first quarter of 2012.

Exploration and Evaluation Expenses

($ millions)	Three months ended March 31, 2013	2012
Seismic, geological and geophysical	33	32
Expensed drilling	52	38
Expensed land	3	5
Exploration and evaluation expense	88	75

Exploration and evaluation expense in the first quarter of 2013 was $88 million compared with $75 million in the first quarter of 2012. The increase in expensed drilling of $14 million was primarily related to activity in Western Canada. Expensed drilling in the first quarter of 2013 primarily consisted of costs related to the winter program at the Slater River Canol Shale project where the Company completed the drilling and testing of two vertical wells and completed the baseline groundwater study.

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

In the first quarter of 2013, total DD&A averaged $19.46/boe compared with $18.18/boe in the first quarter of 2012 as the Company continues to shift focus to investments in oil and liquids rich natural gas properties with offsetting higher netbacks.

Exploration and Production Capital Expenditures

In the first quarter of 2013, Upstream Exploration and Production capital expenditures were $1,066 million. Capital expenditures were $629 million (59%) in Western Canada, $158 million (15%) in the Oil Sands, $144 million (13%) in the Atlantic Region and $135 million (13%) in the Asia Pacific Region. Husky's major projects remain on budget and on schedule.

Exploration and Production Capital Expenditures ($ millions)[1]	Three months ended March 31, 2013	2012
Exploration		
Western Canada	110	87
Atlantic Region	5	-
Asia Pacific Region	6	-
	121	87
Development		
Western Canada	513	577
Oil Sands	158	154
Atlantic Region	139	58
Asia Pacific Region	129	134
	939	923
Acquisitions		
Western Canada	6	5
	1,066	1,015

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

Western Canada, Heavy Oil and Oil Sands

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

	Three months ended March 31,			
Wells Drilled		2013		2012
(wells) [(1)]	Gross	Net	Gross	Net
Exploration				
Oil	15	9	23	18
Gas	5	5	11	10
Dry	-	-	-	-
	20	14	34	28
Development				
Oil	248	229	217	197
Gas	35	15	11	8
Dry	-	-	1	1
	283	244	229	206
Total	303	258	263	234

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

The Company drilled 258 net wells in the Western Canada, Heavy Oil and Oil Sands business units in the first quarter of 2013 resulting in 238 net oil wells and 20 net natural gas wells compared with the drilling of 234 net wells resulting in 215 net oil wells and 18 net natural gas wells in the first quarter of 2012.

Capital expenditures for wells drilled in Western Canada increased in the first quarter of 2013 compared with the same period in 2012 with continued focus on resource play development drilling, an increase in horizontal wells drilled and more multi-stage fracture completions performed.

During the first quarter of 2013, Husky invested $629 million in exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $669 million in the same period in 2012. Property acquisitions totalling $6 million were completed in the first quarter of 2013 compared with $5 million in the same period in 2012. Investment in oil and natural gas exploration and development in each of the first quarter of 2013 and 2012 was $185 million and $175 million, respectively. Investment in natural gas was primarily directed at liquids-rich natural gas resource plays.

In addition, $37 million was spent on production optimization and cost reduction initiatives in the first quarter of 2013. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $93 million in the first quarter of 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $133 million in the first quarter of 2013 compared with $158 million in the same period in 2012.

Oil Sands

During the first quarter of 2013, capital expenditures on Oil Sands projects were $158 million, comparable to the $154 million in the same period in 2012 as Sunrise Phase 1 continues on track. In addition, the Company drilled 34 gross (17 net) evaluation wells for Phase 2 at the Sunrise Energy Project during the first quarter of 2013.

Atlantic Region

During the first quarter of 2013, $144 million was invested in Atlantic Region projects primarily on the continued development of the White Rose Extension Project, including the North Amethyst and South White Rose Extension satellite fields. In addition, the Company commenced drilling on one injector well at North Amethyst and one gas injector well at the South White Rose Extension.

Asia Pacific Region

Total capital expenditures of $135 million were invested in the Asia Pacific Region in the first quarter of 2013 primarily for the development of the Liwan Gas Project.

Infrastructure and Marketing

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

Infrastructure and Marketing Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2013**	2012
Infrastructure gross margin	**32**	23
Marketing and other gross margin	**162**	71
Gross margin	**194**	94
Operating and administrative expenses	**9**	16
Depletion, depreciation and amortization	**6**	5
Other income	**-**	(1)
Income taxes	**45**	18
Net earnings	**134**	56
Commodity trading volumes managed *(mboe/day)*	**180.5**	181.8

Infrastructure and Marketing net earnings in the first quarter of 2013 increased by $78 million compared with the same period in 2012 as a result of marketing activities utilizing the Company's access to infrastructure to move crude oil from Canada to the United States to mitigate the impact of wider Western Canadian crude oil differentials.

In the first quarter of 2013, Infrastructure and Marketing capital expenditures totalled $11 million and were primarily related to pipeline expenditures.

5.2 Downstream

Total First Quarter Downstream Earnings 2013 - $352 million, 2012 - $150 million

Total Downstream net earnings include results from the Upgrader, Canadian Refined Products and U.S. Refining and Marketing. Net earnings on a combined basis reflect the impact of wider differentials for heavy crude oil in the first quarter of 2013 compared with the same period in 2012 resulting in increases in Upgrader margins and higher realized refining margins from lower cost heavy feedstock combined with higher U.S. refining market crack spreads.

Upgrader

Upgrader Earnings Summary *($ millions, except where indicated)*	Three months ended March 31, 2013	2012
Gross revenues	**529**	581
Gross margin[(1)]	**242**	129
Operating and administration expenses[(1)]	**39**	36
Depreciation and amortization	**24**	25
Other expenses	**1**	3
Income taxes	**46**	17
Net earnings	**132**	48
Upgrader throughput *(mbbls/day)* [(2)]	**74.2**	78.8
Synthetic crude oil sales *(mbbls/day)*	**56.1**	61.1
Upgrading differential *($/bbl)*	**38.51**	20.38
Unit margin *($/bbl)*[(1)]	**47.93**	23.20
Unit operating cost *($/bbl)*[(1)(3)]	**5.84**	5.02

(1) *The Company reclassified certain hydrogen feedstock costs from operating and administrative expenses to cost of sales in the third quarter of 2012. The 2012 period has been reclassified to conform with current period presentation.*

(2) *Throughput includes diluent returned to the field.*

(3) *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 oil feedstock and the sales price of synthetic crude oil.

Upgrading net earnings in the first quarter of 2013 were $132 million compared with $48 million in the same period in 2012. The increase was primarily due to higher average upgrading differentials, partially offset by decreased throughput and sales volumes when compared with the same period in 2012.

During the first quarter of 2013, the upgrading differential averaged $38.51/bbl, an increase of $18.13/bbl or 89% compared with the same period in 2012. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The increase in the upgrading differential was attributable to lower feedstock costs as Lloyd Heavy Blend continues to trade at a wide discount to synthetic crude oil due to oversupply and export pipeline constraints. The average price for Husky Synthetic Blend in the first quarter of 2013 was $95.43/bbl compared with $97.68/bbl in the same period in 2012. The overall unit margin increased to $47.93/bbl in the first quarter of 2013 from $23.20/bbl in the same period in 2012 primarily due to lower feedstock costs, partially offset by lower market prices for synthetic crude oil.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2013**	2012
Gross revenues	**843**	880
Gross margin		
Fuel	**36**	35
Refining	**48**	41
Asphalt	**84**	29
Ancillary	**13**	12
	181	117
Operating and administration expenses	**58**	54
Depreciation and amortization	**22**	20
Other expenses	**-**	1
Income taxes	**26**	11
Net earnings	**75**	31
Number of fuel outlets[(1)]	**513**	549
Refined products sales volume		
Light oil products *(millions of litres/day)*	**8.3**	9.1
Light oil products per outlet *(thousands of litres/day)*	**16.1**	16.6
Asphalt products *(mbbls/day)*	**22.3**	20.4
Refinery throughput		
Prince George refinery *(mbbls/day)*	**11.2**	11.1
Lloydminster refinery *(mbbls/day)*	**28.3**	27.2
Ethanol production *(thousands of litres/day)*	**783.3**	722.0

(1) Average number of fuel outlets for period indicated.

Higher refining gross margins in the first quarter of 2013 compared with the same period in 2012 were primarily due to higher refinery throughput and lower feedstock costs. Included in refining gross margins in the first quarter of 2013 and 2012 are government assistance grants of $7 million and $9 million, respectively.

Asphalt gross margins were significantly higher in the first quarter of 2013 compared with the same period in 2012 due to lower blend costs and strong diluent prices.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2013**	2012
Gross revenues	**2,711**	2,492
Gross refining margin	**386**	259
Operating and administration expenses	**105**	95
Depreciation and amortization	**57**	51
Other expenses	**1**	1
Income taxes	**78**	41
Net earnings	**145**	71
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**146.9**	139.4
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**66.3**	67.3
Refining margin *(U.S. $/bbl crude throughput)*	**20.47**	14.14
Refinery inventory *(mmbbls)*[(1)]	**10.9**	10.6

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

U.S. Refining and Marketing net earnings increased in the first quarter of 2013 compared with the same period in 2012 primarily due to favourable market crack spreads, the consumption of lower priced feedstock at both refineries and higher throughput at the Lima Refinery, partially offset by an increase in operating and administrative expenses due to an increase in maintenance activity. The increase in throughput at the Lima Refinery was attributed to a catalyst replacement initiated in the first quarter of 2012 which resulted in a 10-day diesel hydrotreater outage.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis crude oil feedstock costs included in realized margins reflect purchases made earlier in the quarter when crude oil prices were higher. The estimated FIFO impact was an increase in net earnings of approximately $10 million in the first quarter of 2013 compared with an increase in net earnings of $20 million in the same period in 2012.

In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10% to 15% of other products which are sold at discounted market prices compared with gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Downstream Capital Expenditures

In the first quarter of 2013, Downstream capital expenditures totalled $52 million compared with $64 million in the same period in 2012. In Canada, capital expenditures of $25 million were related to upgrades at the Upgrader and the Prince George Refinery. At the Lima Refinery, $18 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $9 million (Husky's 50% share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

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

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

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

5.3 Corporate

Corporate Summary	Three months ended March 31,	
($ millions) income (expense)	**2013**	2012
Administration expenses	**(43)**	(40)
Stock-based compensation	**(9)**	(4)
Depreciation and amortization	**(10)**	(7)
Other income (expenses)	**14**	(5)
Foreign exchange losses	**(8)**	(1)
Interest – net	**(9)**	(20)
Income taxes	**(7)**	7
Net loss	**(72)**	(70)

The Corporate segment reported a loss of $72 million in the first quarter of 2013 compared with a loss of $70 million in the same period in 2012. Interest - net decreased by $11 million compared with the same period in 2012 due to an increase in the amount of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project. Other income in the first quarter of 2013 reflects a refund of insurance premiums.

Foreign Exchange Summary	Three months ended March 31,	
($ millions, except where indicated)	**2013**	2012
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(8)**	32
Losses on cross currency swaps	**-**	(6)
Gains (losses) on contribution receivable	**14**	(18)
Other foreign exchange losses	**(14)**	(9)
Net foreign exchange losses	**(8)**	(1)
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $1.005**	U.S. $0.983
At end of period	**U.S. $0.985**	U.S. $1.001

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

Consolidated Income Taxes

Consolidated income taxes increased slightly in the first quarter of 2013 to $243 million from $239 million in the same period in 2012 resulting in an effective tax rate of 31% in the first quarter of 2013 and 29% in the same period in 2012.

	Three months ended March 31,	
($ millions)	**2013**	2012
Income taxes as reported	**243**	239
Cash taxes paid	**141**	199

Corporate Capital Expenditures

In the first quarter of 2013, Corporate capital expenditures of $23 million were primarily related to computer hardware and software.

6. Liquidity and Capital Resources

6.1 Summary of Cash Flow

In the first quarter of 2013, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At March 31, 2013, Husky had total debt of $3,979 million partially offset by cash on hand of $1,895 million for $2,084 million of net debt compared to $1,893 million of net debt at December 31, 2012. At March 31, 2013, the Company had $3.5 billion of unused credit facilities of which $3.2 billion is long-term committed credit facilities and $281 million is short-term uncommitted credit facilities. In addition, the Company had $3.0 billion in unused capacity under its December 2012 Canadian universal short form base shelf prospectus and U.S. $1.5 billion in unused capacity under its June 2011 U.S. universal short form base shelf prospectus. The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. Refer to Section 6.2.

Cash Flow Summary	Three months ended March 31,	
($ millions, except ratios)	**2013**	2012
Cash flow		
Operating activities	**1,315**	1,483
Financing activities	**(205)**	477
Investing activities	**(1,234)**	(1,126)
Financial Ratios(1)		
Debt to capital employed *(percent)*(2)	**17.0**	19.3
Debt to cash flow *(times)*(3)(4)	**0.8**	0.8
Corporate reinvestment ratio *(percent)*(3)(5)	**106**	107
Interest coverage ratios on long-term debt only(3)(6)		
Earnings	**12.2**	14.2
Cash flow	**23.9**	26.4
Interest coverage on ratios of total debt(3)(7)		
Earnings	**12.1**	13.8
Cash flow	**23.6**	25.6

(1) *Financial ratios constitute non-GAAP measures. Refer to Section 11.*

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

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

(4) *Debt to cash flow (times) is equal to long-term debt and long-term debt due within one year divided by cash flow from operations.*

(5) *Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations.*

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

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

Cash Flow from Operating Activities

In the first quarter of 2013, cash generated from operating activities was $1.3 billion compared with $1.5 billion in the first quarter of 2012. The decrease in cash flow from operating activities was primarily due to an increase in inventory.

Cash Flow from (used for) Financing Activities

In the first quarter of 2013, cash flow used for financing activities was $205 million compared with cash flow from financing activities of $477 million in the same period in 2012. The change was primarily due to higher cash versus stock dividends paid on common shares in the first quarter of 2013 compared with the same period in 2012 and a debt issuance of U.S. $500 million in senior unsecured notes completed in the first quarter of 2012.

Cash Flow used for Investing Activities

In the first quarter of 2013, cash used for investing activities was $1.2 billion compared with $1.1 billion in the same period in 2012. Cash invested in both periods was primarily for capital expenditures.

6.2 Sources of Capital

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

Working capital is the amount by which current assets exceed current liabilities. At March 31, 2013, working capital was $2,176 million compared with $2,401 million at December 31, 2012.

At March 31, 2013, Husky had unused short and long-term borrowing credit facilities totalling $3.5 billion. A total of $235 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

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

On December 14, 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $3.1 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. In February of 2013, this amount was increased to $3.2 billion.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Base Prospectus") with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada up to and including January 30, 2015. As of March 31, 2013, the Company had not issued Securities under the Canadian Base Prospectus. This Canadian Base Prospectus replaced the universal short form base shelf prospectus filed in Canada in November 2010 which had remaining unused capacity of $1.4 billion and expired in December 2012. The ability of the Company to raise capital utilizing the Canadian Base Prospectus and its U.S. universal short form base shelf prospectus is dependent on market conditions at the time of sale.

Capital Structure	**March 31, 2013**	
($ millions)	**Outstanding**	**Available**[(1)]
Total long-term debt	**3,979**	**3,481**
Common shares, retained earnings and other reserves	**19,490**	

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

6.3 Contractual Obligations and Commercial Commitments

In the normal course of business, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to Husky's 2012 Annual MD&A under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2012. At March 31, 2013, Husky did not have any additional material contractual obligations and commercial commitments. There were no material changes to commitments noted during the first quarter of 2013.

6.4 Off-Balance Sheet Arrangements

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

6.5 Transactions with Related Parties and Major Customers

The Company sells natural gas to and purchases steam from the Meridian cogeneration facility and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the three months ended March 31, 2013, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $15 million. For the three months ended March 31, 2013, the amount of steam purchased by the Company from Meridian totalled $5 million. The Company provides facility services to Meridian which are measured at cost. For the three months ended March 31, 2013, the total cost recovery for these services was less than $1 million.

7. Risk Management and Financial Risks

7.1 Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's 2012 Annual Information Form.

The Company has processes in place to identify the principal risks of the business and put in place appropriate mitigation to manage such risks where possible. The Company's exposure to operational, political, environmental, financial, liquidity and contract and credit risk has not changed since December 31, 2012, as discussed in Husky's 2012 Annual MD&A.

7.2 Financial Risks

The following provides an update on the Company's commodity price, interest rate and foreign exchange risk management.

Commodity Price Risk Management

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

At March 31, 2013, the Company was party to crude oil purchase and sale derivative contracts to mitigate its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company was also party to third party physical natural gas purchase and sale derivative contracts in order to mitigate commodity price fluctuations. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities.

Interest Rate Risk Management

At March 31, 2013, the Company had entered into a cash flow hedge using forward starting interest rate swap arrangements whereby the Company fixed the underlying U.S. 10-year Treasury Bond rate on U.S. $500 million to June 16, 2014, which is the Company's forecasted debt issuance on the same date. The effective portion of these contracts has been recorded at fair value in other assets; there was no ineffective portion at March 31, 2013. The weighted average swap rate for these forward starting swaps is 2.24%.

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

Foreign Currency Risk Management

At March 31, 2013, 82% or $3.2 billion of Husky's outstanding debt was denominated in U.S. dollars. Including the debt that has been designated as a hedge of a net investment, 10% of long-term debt is exposed to changes in the Canadian/U.S. exchange rate.

At March 31, 2013, the Company had designated U.S. $2.8 billion of its U.S. denominated debt as a hedge of the Company's net investment in its U.S. refining operations. For the three months ended March 31, 2013, the Company incurred an unrealized loss of $50 million arising from the translation of the debt, net of tax of $7 million, which was recorded in other comprehensive income ("OCI"). At March 31, 2013, the fair value of the hedge was $40 million and is recorded in long-term debt on the condensed interim consolidated balance sheets.

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and a major portion of this receivable is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange in current period earnings. At March 31, 2013, Husky's share of this receivable was U.S. $519 million including accrued interest. The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At March 31, 2013, Husky's share of this obligation was U.S. $1.3 billion including accrued interest. At March 31, 2013, the cost of a Canadian dollar in U.S. currency was $0.985.

The following table summarizes by measurement classification, derivatives, contingent consideration and hedging instruments that are carried at fair value in the interim consolidated balance sheets:

Financial Instruments at Fair Value
($ millions)

	March 31, 2013	December 31, 2012
Derivatives – FVTPL (held-for-trading)		
Accounts receivable	21	13
Accounts payable and accrued liabilities	(24)	(5)
Other assets, including derivatives	3	1
Other – FVTPL (held-for-trading)(1)		
Accounts payable and accrued liabilities	(51)	(27)
Other long-term liabilities	(30)	(78)
Hedging instruments		
Other assets, including derivatives	8	1
Long-term debt(2)	(27)	25
	(100)	(70)
Included in net earnings	(5)	104
Included in other comprehensive income	(45)	18
Net gains (losses) for the period, and year, related to financial instruments held at fair value	(50)	122

(1) *Non-derivative items related to contingent consideration recognized as part of a business acquisition.*
(2) *Represents the foreign exchange adjustment related to translation of U. S. denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.*

8. Critical Accounting Estimates and Key Judgments

Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in Husky's 2012 Annual MD&A, as well as critical areas of judgments have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

9. Change in Accounting Policies

The following new accounting standards and amendments to existing standards, as issued by the International Accounting Standards Board ("IASB"), have been adopted by the Company effective January 1, 2013.

New Accounting Standards

IFRS 10 "Consolidated Financial Statements" provides a single control model to be applied in the assessment of control for all entities in which the Company has an investment. The adoption of this standard had no impact on the Company's financial statements.

IFRS 11 “Joint Arrangements” classifies joint arrangements 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 and apply proportionate consolidation, while parties to a joint venture have rights to the net assets of the venture and apply equity accounting. As a result of identifying and analyzing the applicability of these new standards, the Company's Madura joint arrangement will no longer be accounted for using proportionate consolidation. It will now be accounted for on an equity basis as it meets the IFRS 11 definition of a joint venture. The adoption of this standard resulted in the following cumulative balance sheet impact, applied prospectively from January 1, 2012.

	December 31, 2012	January 1, 2012
Accounts receivable	(4)	(4)
Exploration and evaluation assets	(37)	(14)
Property, plant and equipment, net	(45)	(42)
Investment in joint ventures	132	91
Other assets	(25)	-
Accounts payable and accrued liabilities	1	18
Other long-term liabilities	3	(24)
Deferred tax liabilities	(25)	(25)
Total Balance Sheet Impact	-	-

IFRS 12 “Disclosure of Interests in Other Entities” contains new disclosure requirements for interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. The adoption of this standard had an immaterial impact on the Company's annual financial statement disclosures.

IFRS 13 “Fair Value Measurement” establishes a single source of guidance for fair value measurement and disclosure of financial and non-financial items under IFRS. The adoption of this standard had an immaterial impact on the Company's financial statements.

Amendments to Standards

Amendments to IFRS 7 “Financial Instruments Disclosures” require additional disclosures regarding the Company's financial assets and financial liabilities that are subject to set-off rights and related arrangements. Refer to Note 11 of the Condensed Interim Consolidated Financial Statements for the additional disclosure required.

Amendments to IAS 28 “Investments in Associates and Joint Ventures” provide additional guidance applicable to accounting for interests in joint ventures or associates using the equity method of accounting. The adoption of this amended standard had no impact on the Company's financial statements.

Amendments to IAS 19 “Employee Benefits” replaced the corridor approach with immediate recognition of actuarial re-measurements and past service costs, modified the calculation of benefit costs and eliminated the expected returns on plan assets through profit or loss. Additional disclosures regarding risk, judgments and assumptions are required. The additional requirement had an immaterial impact on the Company's annual financial statement disclosures.

The adoption of this amended standard resulted in the following balance sheet impact, applied retrospectively to January 1, 2010.

(millions of Canadian dollars) (unaudited)	2012	2011	2010	**Total**
Increase/(decrease) in net defined benefit liability	1	2	(12)	**(9)**
Increase/(decrease) in retained earnings	(1)	(2)	12	**9**
Total balance sheet impact	-	-	-	**-**

10. Outstanding Share Data

Authorized:

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

Issued and outstanding: May 1, 2013

• common shares	982,854,689
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	33,241,340
• stock options exercisable	12,497,963

11. Reader Advisories

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

Readers are encouraged to refer to Husky's 2012 Annual MD&A, the 2012 Consolidated Financial Statements and the 2012 Annual Information Form filed with Canadian securities regulatory authorities and the 2012 Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency, for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended March 31, 2013 are compared with results for the three months ended March 31, 2012. Discussions with respect to Husky's financial position as at March 31, 2013 are compared with its financial position at December 31, 2012. Amounts presented within this MD&A are unaudited.

Additional Reader Guidance

- The Condensed Interim Consolidated Financial Statements and comparative financial information included in this MD&A have been prepared in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting" as issued by the IASB.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended March 31, 2013 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this MD&A are cash flow from operations, adjusted net earnings, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt and interest coverage on total debt. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of cash flow from operations and adjusted net earnings, there are no comparable measures in accordance with IFRS. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application. Except as described below, the definitions of these measurements are found in Section 6.1.

Disclosure of Adjusted Net Earnings

The term “Adjusted Net Earnings” is a non-GAAP measure comprised of net earnings adjusted for certain items not considered indicative of the Company's on-going financial performance. Adjusted net earnings is a complementary measure used in assessing Husky's financial performance through providing comparability between periods.

The following table shows the reconciliation of net earnings to adjusted net earnings and related per share amounts for the three months ended March 31, 2013:

		Three months ended March 31,	
($ millions)		**2013**	2012
GAAP	Net earnings	**535**	591
	Foreign exchange	**6**	-
	Financial instruments	**(1)**	(28)
	Stock-based compensation	**7**	3
Non-GAAP	Adjusted net earnings	**547**	566
	Adjusted net earnings – basic	**0.56**	0.59
	Adjusted net earnings – diluted	**0.56**	0.58

Disclosure of Cash Flow from Operations

Husky uses the term “Cash Flow From Operations,” which should not be considered an alternative to, or more meaningful than “cash flow – operating activities” as determined in accordance with IFRS, as an indicator of financial performance. Cash flow from operations is presented in the Company’s financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, exploration and evaluation expense, deferred income taxes, foreign exchange, gain or loss on sale of property, plant, and equipment and other non-cash items.

The following table shows the reconciliation of cash flow – operating activities to cash flow from operations and related per share amounts for the three months ended March 31, 2013:

		Three months ended March 31,	
($ millions)		**2013**	2012
GAAP	Cash flow – operating activities	**1,315**	1,483
	Settlement of asset retirement obligations	**43**	33
	Income taxes paid	**141**	199
	Interest received	**(3)**	(11)
	Change in non-cash working capital	**(213)**	(532)
Non-GAAP	Cash flow from operations	**1,283**	1,172
	Cash flow from operations – basic	**1.31**	1.21
	Cash flow from operations – diluted	**1.30**	1.20

Cautionary Note Required by National Instrument 51-101

The Company uses the term barrels of oil equivalent (“boe”), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

Terms

Adjusted Net Earnings	*Net earnings plus after-tax foreign exchange gains and losses, gains and losses from the use of financial instruments, stock-based compensation or recovery and any asset impairments and write-downs*
Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Capital Employed	*Short and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid, interest received and changes in non-cash working capital*
Coal Bed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Corporate Reinvestment Ratio	*Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations*
Debt to Capital Employed	*Long-term debt and long-term debt due within one year divided by capital employed*
Debt to Cash Flow	*Long-term debt and long-term debt due within one year divided by cash flow from operations*
Delineation Well	*A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Equity	*Shares, retained earnings and other reserves*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Feedstock	*Raw materials which are processed into petroleum products*
Front End Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Hectare	*One hectare is equal to 2.47 acres*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
Interest Coverage Ratio	*A calculation of a company's ability to meet its interest payment obligation. It is equal to net earnings or cash flow – operating activities before finance expense divided by finance expense and capitalized interest*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Return on Average Capital Employed	*Net earnings plus after tax interest expense divided by the two-year average capital employed*
Return on Equity	*Net earnings divided by the two-year average shareholder's equity*
Seismic	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Shares, retained earnings and other reserves*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

Abbreviations

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

12. Forward-Looking Statements and Information

Certain statements in this 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 forward-looking statements contained in this interim report are forward-looking and not historical facts. Such forward-looking statements are based on the Company's current expectations, estimates, projections and assumptions that were made by the Company in light of its experience and its perception of historical trends. Further, such forward-looking statements 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 or projected in the forward-looking statements.

Some of the forward-looking statements and information may be identified by 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"). In particular, forward-looking statements in this interim report include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; and the Company's 2013 production guidance;
- with respect to the Company's Asia Pacific region: planned timing of first production from the Company's Liwan Gas Project; expected timing of completions on production wells at the Company's Liwan Gas Project; anticipated timing of first gas from the Company's Madura Strait block; and planned timing of completion of a 2D-seismic survey program on the Company's recently acquired offshore Taiwan exploration block;

- with respect to the Company's Atlantic region: anticipated first production at the South White Rose Extension project; second quarter drilling plans at the Harpoon exploration well; and the planned in-service date of a water injection well at the Company's North Amethyst field;
- with respect to the Company's Oil Sands properties: anticipated timing of first production at Phase I of the Company's Sunrise Energy project; anticipated timing of completion of well pads and pipelines at the Company's Sunrise Energy Project; expected timing of completion of DBM; anticipated timing of filing a regulatory application for a bitumen carbonate pilot at the Company's Saleski property; and anticipated timing of production from wells at the pilot project at the Company's McMullen property;
- with respect to the Company's Heavy Oil properties: scheduled timing of first production from the Company's Sandall heavy oil thermal development project; anticipated timing of first production at the Company's Rush Lake commercial project; and the Company's 2013 drilling program for both horizontal wells and CHOPS wells;
- with respect to the Company's Western Canadian oil and gas resource plays: planned timing of resumption of operations at the Company's Slater River Canol Shale project; and
- with respect to the Company's Downstream operating segment: anticipated increase in storage volume from the multi-year Hardisty terminal expansion project; scheduled timing and anticipated duration of turnarounds at the Company's Lloydminster Refinery, Lima Refinery and Lloydminster Upgrader.

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.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky.

The Company's Annual Information Form for the year ended December 31, 2012 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.