FOURTH QUARTER INTERIM REPORT FEBRUARY 3, 2010

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1. Summary of Quarterly Results

- Net earnings in the quarter up 39% and cash flow from operations up 99% compared with the fourth quarter of 2008 due to significantly improved U.S. Downstream results. Fourth quarter 2008 results included significant foreign exchange gains and stock compensation recoveries.
- Total operating costs decreased to $578 million in the fourth quarter of 2009 compared to $685 million in the fourth quarter of 2008 as a result of a consistent focus on operational efficiency, reliability and financial discipline.
- Financial position remains strong with debt to cash flow ratio of 1.3 and debt to capital employed ratio of 18.3%.
- Overall production for the quarter impacted by lower natural gas production as a result of lower capital expenditures and production shut-ins and the decline in production from the White Rose field as a result of the planned tie-in work associated with the North Amethyst satellite development and normal field decline.
- Major capital projects are on schedule. The Sunrise oil sands project front end engineering and design ("FEED") is complete and Liwan FEED is approximately 96% complete.
- Successful completion of White Rose planned maintenance and North Amethyst subsea installation.
- Successful exploration well Liuhua 34-2-1 on Block 29/26 in the South China Sea which tested natural gas, with a high liquids yield, at an equipment restricted rate of 55 mmcf/day, with indications that the well's future deliverability could exceed 140 mmcf /day.

Quarterly Financial Summary [1]	Three months ended								Year ended	
	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31	December 31	
(millions of dollars, except per share amounts)	**2009**	2009	2009	2009	2008	2008	2008	2008	**2009**	2008
Sales and operating revenues, net of royalties	**$ 3,605**	$ 3,903	$ 3,916	$ 3,650	$ 4,701	$ 7,715	$ 7,199	$ 5,086	**$15,074**	$24,701
Net earnings	**320**	338	430	328	231	1,274	1,358	888	**1,416**	3,751
Per share - Basic and diluted	**0.38**	0.40	0.51	0.39	0.27	1.50	1.60	1.05	**1.67**	4.42
Cash flow from operations	**657**	452	833	565	330	1,999	2,079	1,538	**2,507**	5,946
Per share - Basic and diluted	**0.77**	0.53	0.98	0.67	0.39	2.35	2.45	1.81	**2.95**	7.00

[1] 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.

2. Business Environment

Average Benchmarks		Year ended December		Three months ended					
		2009	2008	**Dec. 31 2009**	Sept. 30 2009	June 30 2009	March 31 2009	Dec. 31 2008	Sept. 30 2008
WTI crude oil [(1)]	*(U.S. $/bbl)*	**61.80**	99.65	**76.19**	68.30	59.62	43.08	58.73	117.98
Brent crude oil [(2)]	*(U.S. $/bbl)*	**61.54**	96.99	**74.56**	68.43	58.79	44.40	54.91	114.78
Canadian light crude 0.3% sulphur	*($/bbl)*	**66.19**	102.84	**76.75**	71.82	66.21	50.09	63.92	122.53
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**53.60**	72.44	**62.66**	59.83	56.36	35.72	39.76	96.17
NYMEX natural gas [(1)]	*(U.S. $/mmbtu)*	**3.99**	9.04	**4.17**	3.39	3.50	4.89	6.94	10.24
NIT natural gas	*($/GJ)*	**3.92**	7.70	**4.01**	2.87	3.47	5.34	6.43	8.76
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**9.93**	20.38	**12.37**	10.26	7.72	9.20	19.41	18.34
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**8.43**	11.17	**4.92**	8.38	10.91	9.49	6.37	17.01
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**8.33**	9.96	**6.06**	8.03	9.05	10.15	6.59	11.60
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.880**	0.937	**0.947**	0.912	0.858	0.803	0.825	0.960

(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.

Oil and Gas Prices

The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production offshore the East Coast of Canada is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2009 at U.S. $79.36/bbl, recovering from U.S. $44.60/bbl on December 31, 2008, averaging U.S. $61.80/bbl in 2009 compared with U.S. $99.65/bbl in 2008, and U.S. $76.19/bbl in the fourth quarter of 2009 compared with U.S. $58.73/bbl in the fourth quarter of 2008. The price of Brent ended 2009 at U.S. $77.67/bbl, recovering from U.S. $36.55/bbl on December 31, 2008, and averaged U.S. $61.54/bbl in 2009 compared with U.S. $96.99/bbl in 2008, and averaged U.S. $74.56/bbl in the fourth quarter of 2009 compared with U.S. $54.91/bbl in the fourth quarter of 2008.

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 2009, 47% of Husky's crude oil production was heavy oil or bitumen compared with 42% in 2008. The light/heavy crude oil differential averaged U.S. $9.93 or 16% of WTI in 2009 compared with U.S. $20.38 or 20% of WTI in 2008. In the fourth quarter of 2009, 50% of Husky's crude oil production was heavy oil or bitumen compared with 42% in the fourth quarter of 2008. The light/heavy crude oil differential averaged U.S. $12.37/bbl in the fourth quarter of 2009 compared with U.S. $19.41/bbl in the fourth quarter of 2008.

The near-month natural gas price quoted on the NYMEX ended 2009 at U.S. $5.57/mmbtu and U.S. $5.62/mmbtu at December 31, 2008. During 2009, the NYMEX near-month contract price of natural gas averaged U.S. $3.99/mmbtu compared with U.S. $9.04/mmbtu in 2008. During the fourth quarter of 2009, the NYMEX near-month contract price of natural gas averaged U.S. $4.17/mmbtu compared with U.S. $6.94/mmbtu in the fourth quarter of 2008. Low natural gas prices continue to reflect higher than average storage levels and the decline in industrial consumption as a result of reduced economic activity. At the end of 2009, U.S. natural gas inventories were 14% higher than the five-year average and 13% higher than the previous year.

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.

The Canadian dollar ended 2008 at U.S. $0.817 and subsequently strengthened by 17% against the U.S. dollar during 2009, closing at U.S. $0.956 at December 31, 2009. In 2009, the Canadian dollar averaged U.S. $0.880 compared with U.S. $0.937 during 2008. During the fourth quarter of 2009, the Canadian dollar averaged U.S. $0.947

compared with U.S. $0.825 during the fourth quarter of 2008.

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 2009, the Chicago 3:2:1 crack spread averaged U.S. $8.43/bbl compared with U.S. $11.17/bbl in 2008. During 2009, the New York Harbor 3:2:1 crack spread averaged U.S. $8.33/bbl compared with U.S. $9.96/bbl in 2008. During the fourth quarter of 2009, the Chicago 3:2:1 crack spread averaged U.S. $4.92/bbl compared with U.S. $6.37/bbl in the fourth quarter of 2008. During the fourth quarter of 2009, the New York Harbor 3:2:1 crack spread averaged U.S. $6.06/bbl compared with U.S. $6.59/bbl in the fourth quarter of 2008.

During 2009, the 3:2:1 crack spreads were lower than the same period in 2008 reflecting the continuing weak U.S. economic environment. The weak economy has reduced demand for transportation fuels and resulted in high inventory and weak margins. Husky's realized refining margins are affected by the product configuration of its refineries 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 Canadian generally accepted accounting principles ("GAAP").

Cost Environment

The oil and gas industry experienced an increase in costs in excess of the general rate of inflation during the recent years of increasing energy prices. These increases affect the cost of operating the Company's oil and gas properties, processing plants and refineries. They also affect capital projects which are susceptible to cost volatility. During the latter half of 2009, the cost environment began to partially reflect the decline in energy commodity prices and the effect of the current economic conditions.

Global Economic and Financial Environment

The global economic and financial crisis reduced liquidity in financial markets, restricted access to financing and caused significant demand destruction for commodities and lower pricing. This affected the economy in the latter half of 2008 and continued into 2009.

In the wake of the economic downturn, world oil consumption declined and commercial inventories of crude oil are above average historical levels. The Energy Information Administration's ("EIA") January 12, 2010 Short-term Energy Outlook[1] indicates that world oil consumption declined by 1.7 mmbbls/day in 2009 compared with the previous year, primarily in OECD countries. Preliminary data indicates that oil consumption during the fourth quarter of 2009 was 0.3 mmbbls/day higher than the same period in 2008. The EIA now expects oil consumption to increase in 2010 by 1.1 mmbbls/day and 1.5 mmbbls/day in 2011 compared with 2009. Growth of oil consumption in 2010 is expected to result primarily from a resurgence in the global economy. Non-OECD countries are expected to account for most of the increase in 2010. China continues to lead world consumption growth with projected increases of consumption of more than 0.4 mmbbls/day in 2010 and 2011. The EIA estimated non-OPEC supply of crude oil averaged 50.3 mmbbls/day in 2009, up approximately 0.6 mmbbls/day compared with 2008. Most of the increase was from the United States, South America and the Former Soviet Union partially offset by lower production from the North Sea and Mexico. OPEC production was 29.1 mmbbls/day in 2009, down 2.2 mmbbls/day from the previous year. OPEC production is expected to trend upward in 2010 to average 29.5 mmbbls/day and 30.0 mmbbls/day in 2011, in line with increased demand.

Demand for natural gas in North American markets has also retracted in line with lower industrial and commercial consumption; as a result, working gas in storage has averaged above five year levels. The EIA estimates a 1.5% decline in natural gas consumption in 2009 and forecasts consumption in 2010 will remain unchanged but expects a 0.4% higher consumption in 2011 as the industrial sector increases activity. The EIA estimates that natural gas production in 2009 increased by 3.7% compared with the previous year and forecasts a decrease of 3.0% in 2010 followed by an increase of 1.3% in 2011. The EIA estimates

Note:
[1] *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – January 12, 2010 Release*

pipeline imports declined by 0.9 bcf/day or 8.8% during 2009 in response to low prices and expects this trend to continue with reduced natural gas imports of more than 1 bcf/day in 2010. The EIA estimates 2009 liquefied natural gas ("LNG") imports at 1.3 bcf/day compared with 1.0 bcf/day and forecasts 1.8 bcf/day in 2010. The EIA expects U.S. LNG imports will increase as supply increases from Russia, Yemen, Qatar and Indonesia.

In its January Outlook the EIA estimates that fuel consumption in the United States in 2009 fell by 810 mbbls/day or 4.2% including 330 mbbls or 8.3% of diesel fuel and 130 mbbls or 8.4% of jet fuel. Consumption of motor gasoline is expected to increase marginally by 0.1% as lower gasoline prices have partially offset the effects of lower economic activity. The EIA's January Outlook expects a 210 mbbls/day or 1.1% increase in fuel consumption in 2010. According to the EIA data released on January 13, 2010, U.S. gasoline stocks were 223.5 mmbbls, 10.0 mmbbls higher than the previous year; U.S. distillate stocks were 160.4 mmbbls, 16.2 mmbbls higher than the previous year.

The current prospect that demand for energy will increase in 2010 depends on a number of assumptions about timing and sustainability of a global economic recovery.

Companies with low operating costs and flexible capital expenditure plans, strong cash generation from operations, available cash, low debt with long maturities and unused committed credit facilities will be better positioned to manage through adverse economic conditions.

In view of the economic environment, Husky took action in the latter half of 2008 and prudently reduced capital spending in 2009 and continues to review and implement cost containment and efficiency opportunities throughout the organization. Husky's cash position, credit facilities and access to debt capital markets provide adequate liquidity to meet the Company's needs at present, and the Company continues to examine ways of enhancing its access to capital on an ongoing basis.

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 2009. 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	2009 Fourth Quarter Average	Increase	Effect on Annual Pre-tax Cash Flow [6]		Effect on Annual Net Earnings [6]	
			($ millions)	*($/share)* [7]	*($ millions)*	*($/share)* [7]
Upstream and Midstream						
WTI benchmark crude oil price [1]	$ 76.19	*U.S. $1.00/bbl*	64	0.08	46	0.05
NYMEX benchmark natural gas price [2]	$ 4.17	*U.S. $0.20/mmbtu*	24	0.03	17	0.02
WTI/Lloyd crude blend differential [3]	$ 12.37	*U.S. $1.00/bbl*	(4)	-	(4)	-
Downstream						
Canadian light oil margins	$ 0.022	*Cdn $0.005/litre*	14	0.02	10	0.01
Asphalt margins	$ 6.82	*Cdn $1.00/bbl*	7	0.01	5	0.01
New York Harbor 3:2:1 crack spread [4]	$ 6.06	*U.S. $1.00/bbl*	60	0.07	38	0.04
Consolidated						
Exchange rate (U.S. $ per Cdn $) [1] [5]	$ 0.947	*U.S. $0.01*	(51)	(0.06)	(38)	(0.04)
Interest rate		*100 basis points*	(1)	-	(1)	-

(1) Does not include gains or losses on inventory.
(2) Includes decrease in net earnings related to natural gas consumption.
(3) Excludes impact on asphalt operations.
(4) Relates to U.S. Refining & Marketing.
(5) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.
(6) Excludes mark to market accounting impacts.
(7) Based on 849.9 million common shares outstanding as of December 31, 2009.

3. Results of Operations

3.1 Upstream

Upstream Net Earnings Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2009**	2008	**2009**	2008
Gross revenues	**$ 1,451**	$ 1,566	**$ 5,313**	$ 9,932
Royalties	**251**	271	**861**	2,043
Net revenues	**1,200**	1,295	**4,452**	7,889
Operating and administration expenses	**372**	396	**1,495**	1,596
Depletion, depreciation and amortization	**351**	394	**1,397**	1,505
Other expense	**-**	59	**-**	31
Income taxes	**143**	104	**447**	1,380
Net earnings	**$ 334**	$ 342	**$ 1,113**	$ 3,377

Fourth Quarter

Upstream earnings in the fourth quarter of 2009 decreased by $8 million compared with the fourth quarter of 2008 primarily as a result of increases in the prices realized for crude oil and savings in operating costs offset by a 19% decline in production, a 42% decline in natural gas prices and the recognition in the fourth quarter of 2008 of a future income tax recovery related to international projects.

Production of crude oil and natural gas declined mainly due to lower light oil production off the East Coast of Canada as a result of the planned extended shutdown at White Rose for tie-in work associated with satellite development and scheduled maintenance which was completed in early October 2009 along with normal reservoir production decline. The ramp up of production at White Rose post turnaround resulted in lower daily production compared with the same period in 2008. Natural gas production in Western Canada declined due to the impact of low capital expenditures and the decision to shut in production as a result of the low commodity price environment.

Average realized prices in the fourth quarter of 2009 were $66.65/bbl for crude oil, NGL and bitumen combined compared with $49.02/bbl during the same period in 2008. Natural gas prices averaged $3.94/mcf in the fourth quarter of 2009 compared with $6.84/mcf in the same period in 2008.

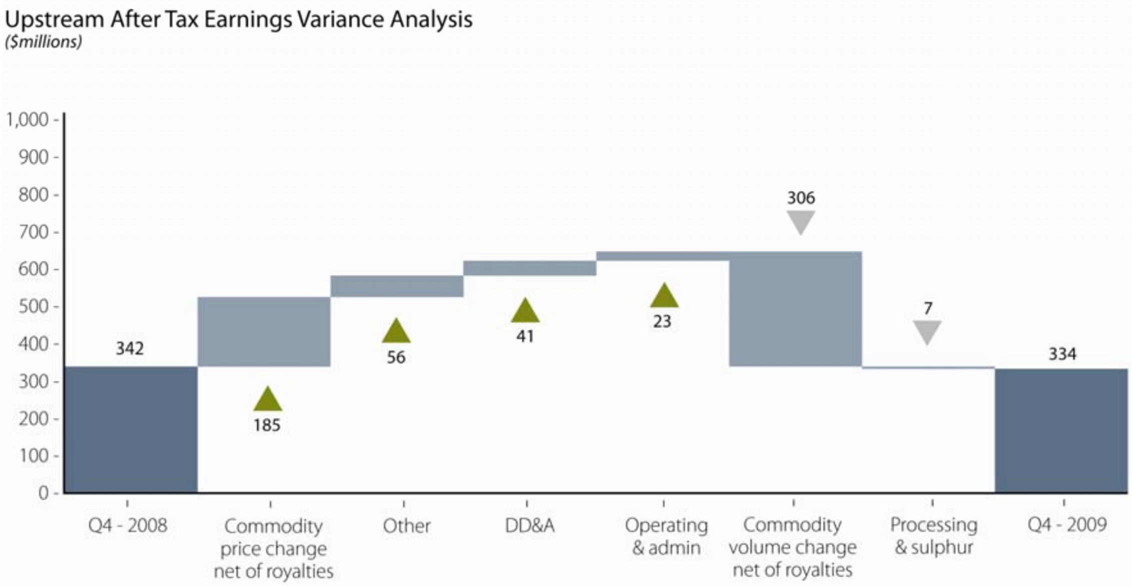
Twelve Months

Upstream earnings in 2009 were $2,264 million lower than in 2008 as a result of lower average realized prices for commodities combined with lower production in Western Canada and offshore East Coast of Canada.

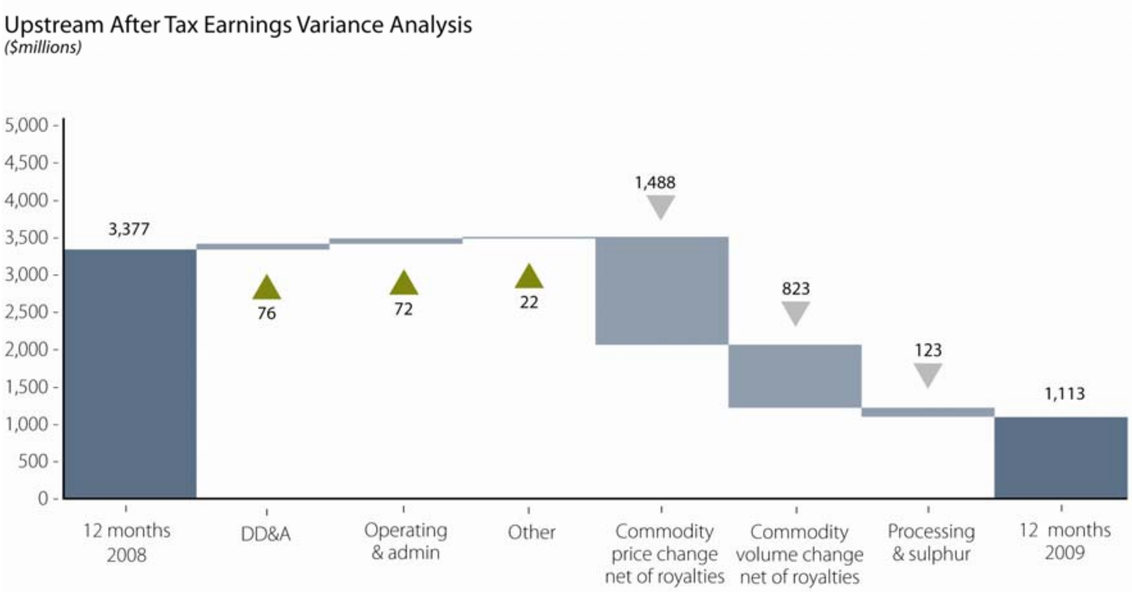
During 2009, average realized prices declined 33% to $57.11/bbl for crude oil, NGL and bitumen combined compared with $84.96/bbl during 2008. The narrowing light to heavy crude oil differential in 2009 compared with 2008 partially offset the impact on earnings of declining light crude oil prices. Average realized natural gas prices declined 52% to $3.83/mcf in 2009 compared with $7.94/mcf in 2008.

Upstream Net Earnings Variance Analysis

Fourth Quarter



Twelve Months



Pricing

Average Sales Prices Realized		Three months ended Dec. 31		Year ended Dec. 31	
		2009	2008	**2009**	2008
Crude oil	*($/bbl)*				
Light crude oil & NGL		**$ 73.98**	$ 58.43	**$ 62.70**	$ 97.28
Medium crude oil		**65.78**	47.02	**56.37**	81.79
Heavy crude oil		**61.55**	39.08	**52.54**	71.98
Bitumen		**60.70**	37.93	**51.90**	70.24
Total average		**66.65**	49.02	**57.11**	84.96
Natural gas	*($/mcf)*				
Average		**3.94**	6.84	**3.83**	7.94

Oil and Gas Production

Daily Gross Production		Three months ended Dec. 31		Year ended Dec. 31	
		2009	2008	**2009**	2008
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**22.4**	24.7	**22.8**	24.6
Medium crude oil		**24.8**	26.6	**25.4**	26.9
Heavy crude oil [(1)]		**78.6**	86.8	**78.6**	84.3
Bitumen [(1)]		**23.3**	23.9	**23.1**	22.7
		149.1	162.0	**149.9**	158.5
East Coast Canada					
White Rose - light crude oil		**34.8**	77.2	**45.2**	73.2
Terra Nova - light crude oil		**9.0**	11.5	**10.0**	12.9
China					
Wenchang - light crude oil & NGL		**10.5**	12.5	**11.1**	12.2
Total crude oil & NGL		**203.4**	263.2	**216.2**	256.8
Natural gas	*(mmcf/day)*	**528.7**	571.1	**541.7**	594.4
Total	*(mboe/day)*	**291.5**	358.4	**306.5**	355.9

[(1)] Restated in accordance with the U.S. Securities and Exchange Commission definition of bitumen, as part of its new requirements for oil and gas reserves disclosure effective December 31, 2009. Under the new definition, a portion of crude oil previously reported as heavy crude oil has now been reclassified as bitumen. The presentation of heavy crude oil and bitumen reported in prior periods has been restated to reflect the new definition.

Crude Oil and NGL Production

Fourth Quarter

Crude oil and NGL production in the fourth quarter of 2009 decreased by 59.8 mbbls/day or 23% compared with 2008. Off the East Coast of Canada, production from White Rose decreased by 42.4 mbbls/day or 55% due primarily to a planned extended shutdown for tie-in work associated with the North Amethyst satellite development and scheduled maintenance combined with general declines in daily production rates post start up. Production from the Southern Drill Centre was shut-in on July 21, 2009 and resumed production on October 8, 2009. At Terra Nova, production was shut-in on September 17, 2009 for scheduled maintenance and resumed on October 6, 2009. In addition, facility operational issues at Terra Nova resulted in lower production in the fourth quarter of 2009 compared with the same period in 2008.

During the fourth quarter of 2009, crude oil, bitumen and NGL production from Western Canada decreased by 12.9 mbbls/day or 8% compared with the fourth quarter of 2008 primarily due to the impact of lower capital expenditures and the shut-in of higher cost facilities as a result of low commodity prices and reservoir decline partially offset by the acquisition of heavy oil assets in the fourth quarter of 2009.

Production at Wenchang was lower in the fourth quarter of 2009 compared with 2008 due to workover and maintenance operations.

Twelve Months

During 2009, crude oil and NGL production decreased by 40.6 mbbls/day or 16%. Production at White Rose decreased approximately 28.0 mbbls/day during 2009. In addition to the factors impacting the fourth quarter, White Rose production was reduced due to subsea operational issues which commenced in October 2008 and were resolved in June 2009. Production was also impacted in the spring by heavy iceberg conditions, which resulted in facility throughput restrictions on the *SeaRose FPSO*. At Terra Nova, facility operational issues resulted in lower production in 2009 compared with 2008.

Natural Gas Production

Fourth Quarter

Production of natural gas decreased by 42.4 mmcf/day or 7% in the fourth quarter of 2009 compared with the fourth quarter of 2008 due to lower capital expenditures on drilling and tie-ins and the shut-in of higher cost facilities as a result of lower commodity prices, flowline restrictions and general reservoir decline.

Twelve Months

In 2009, natural gas production decreased by 52.7 mmcf/day or 9% compared with 2008 primarily due to the same factors impacting the fourth quarter.

2009 Production Guidance			Actual Production	
		Guidance 2009	Year ended Dec. 31 **2009**	Year ended Dec. 31 2008
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		92 - 109	**89**	123
Medium crude oil		25 - 28	**25**	27
Heavy crude oil & bitumen		95 - 105	**102**	107
		212 - 242	**216**	257
Natural gas	*(mmcf/day)*	585 - 620	**542**	594
Total barrels of oil equivalent	*(mboe/day)*	310 - 345	**307**	356

Royalties

Fourth Quarter

Royalty rates averaged 17% for both the fourth quarter of 2009 and 2008. Royalty rates in Western Canada averaged 15% as a percentage of gross revenue, up from 14% in the fourth quarter of 2008. The East Coast of Canada rates averaged 24% compared with 25% in the fourth quarter of 2008 primarily as a result of the impact of lower production on the overall royalty rate which is a combination of royalties based on gross revenues and net cash flow. Royalty rates in Wenchang averaged 23% compared with 15% in the fourth quarter of 2008. The royalty rate for Wenchang has increased due to the sliding scale royalty clause in the Production Sharing Contract ("PSC") that results in higher rates in higher commodity price environments.

Twelve Months

Royalty rates averaged 16% of gross revenue in 2009 compared with 21% in 2008. Royalty rates in Western Canada averaged 13% compared with 16% in 2008 and off the East Coast of Canada the average rate was 25% compared with 28% in 2008. In addition to the factors impacting the fourth quarter, the decrease was primarily due to lower average commodity prices in 2009 compared with 2008 which resulted in lower price sensitive rates in Western Canada combined with positive adjustments to 2008 royalties recorded in 2009 as a result of annual reconciliations filed in accordance with East Coast royalty regulations.

Operating Costs

	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2009**	2008	**2009**	2008
Western Canada	**$ 289**	$ 317	**$ 1,124**	$ 1,249
East Coast Canada	**33**	35	**177**	157
International	**8**	7	**23**	22
Total	**$ 330**	$ 359	**$ 1,324**	$ 1,428
Unit operating costs ($/boe)	**$ 12.24**	$ 10.84	**$ 11.82**	$ 10.93

Fourth Quarter

Total upstream operating costs have decreased to $330 million from $359 million primarily as a result of reduced energy, treating and maintenance costs. Total upstream unit operating costs in the fourth quarter of 2009 averaged $12.24/boe compared with $10.84/boe in the fourth quarter of 2008, as lower costs were offset by lower production.

Operating costs in Western Canada decreased to $289 million from $317 million and averaged $13.21/boe in the fourth quarter of 2009 compared with $13.28/boe in 2008 primarily as a result of lower energy and treating costs partially offset by higher servicing and labour costs combined with lower production. Maturing fields in Western Canada require increasing amounts of infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive pipeline systems, crude and water trucking and more complex natural gas compression systems. Husky is focused on managing operating costs associated with the increased infrastructure through cost reduction and efficiency initiatives and keeping infrastructure fully utilized.

Operating costs at the East Coast offshore operations averaged $8.10/boe in the fourth quarter of 2009 compared with $4.32/boe in 2008 primarily as a result of lower production and higher maintenance costs.

Operating costs at the South China Sea offshore operations averaged $7.33/boe in the fourth quarter of 2009 compared with $5.54/boe in 2008 as a result of higher maintenance costs combined with lower production.

Twelve Months

Total upstream operating costs in 2009 compared with 2008 decreased to $1,324 million from $1,428 million. Total upstream unit operating costs in 2009 averaged $11.82/boe compared with $10.93/boe in 2008 as lower costs were offset by lower production. Operating costs in Western Canada decreased to $1,124 million from $1,249 million and averaged $12.83/boe in 2009 compared with $13.16/boe in 2008 primarily as a result of lower energy and treating costs partially offset by higher maintenance, land and labour costs.

Operating costs at the East Coast offshore operations averaged $8.73/boe in 2009 compared with $4.99/boe in 2008 primarily as a result of the same factors impacting the fourth quarter.

Operating costs at the South China Sea offshore operations averaged $5.35/boe in 2009 compared with $4.78/boe in 2008 primarily as a result of lower production.

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

Fourth Quarter

In the fourth quarter of 2009, total unit DD&A averaged $13.10/boe compared with $11.95/boe in the fourth quarter of 2008. The higher DD&A rate in 2009 was primarily due to lower oil and gas reserves as a result of commodity price adjustments at December 31, 2008 and a higher full cost base in 2009.

Twelve Months

During 2009, total unit DD&A averaged $12.49/boe compared with $11.56/boe during 2008 primarily due to lower oil and gas reserves and a higher full cost base, partially offset by the effect of the disposition of 50% of the Sunrise oil sands asset on March 31, 2008.

Other Items

A loss of $60 million was recorded in the fourth quarter of 2008 and a loss of $101 million was recorded for 2008 on a drilling contract previously treated as an embedded derivative. In the fourth quarter of 2008 it was determined that the contract no longer met the criteria of an embedded derivative and the related accounting treatment was discontinued. In 2008, a gain of $69 million was recognized on the sale of 50% of Husky Oil (Madura) Limited to CNOOC Ltd.

Upstream Capital Expenditures

In 2009, upstream capital expenditures were $2,326 million, $1,189 million (51%) in Western Canada, $574 million (25%) offshore the East Coast of Canada, $507 million (22%) in South East Asia, $25 million (1%) in the Northwest United States and $31 million (1%) offshore Greenland.

Capital Expenditures Summary [1]	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2009**	2008	**2009**	2008
Exploration				
Western Canada	**$ 134**	$ 204	**$ 266**	$ 680
East Coast Canada and Frontier	**11**	66	**64**	160
Northwest United States	**10**	10	**25**	60
International	**153**	110	**526**	225
	308	390	**881**	1,125
Development				
Western Canada	**445**	611	**923**	1,881
East Coast Canada	**84**	171	**510**	569
International	**4**	2	**12**	5
	533	784	**1,445**	2,455
	$ 841	$ 1,174	**$ 2,326**	$ 3,580

(1) *Excludes capitalized costs related to asset retirement obligations incurred during the period and the BP joint venture transaction.*

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

Western Canada and Oil Sands Wells Drilled		Three months ended Dec. 31				Year ended Dec. 31			
		2009		2008		**2009**		2008	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**9**	**5**	42	34	**18**	**9**	80	70
	Gas	**3**	**-**	21	15	**37**	**22**	102	79
	Dry	**1**	**1**	4	2	**7**	**6**	27	23
		13	**6**	67	51	**62**	**37**	209	172
Development	Oil	**136**	**116**	230	190	**315**	**278**	685	578
	Gas	**19**	**8**	143	78	**122**	**61**	435	270
	Dry	**2**	**2**	20	20	**7**	**7**	36	36
		157	**126**	393	288	**444**	**346**	1,156	884
Total		**170**	**132**	460	339	**506**	**383**	1,365	1,056

Western Canada

During 2009, Husky invested $1,189 million on exploration and development throughout the Western Canada Sedimentary Basin compared with $2,561 million in 2008. Of this, $379 million was invested on oil development and $143 million was invested on natural gas development compared with $678 million for oil development and $360 million for natural gas development in 2008. The Company drilled 383 net wells in the basin resulting in 287 net oil wells and 83 net natural gas wells compared with 648 net oil wells and 349 net natural gas wells in 2008. The reduction in capital expenditures, in particular natural gas drilling, reflects the Company's decision to reduce activity in this area in 2009 due to the low commodity price environment. In addition, $80 million was spent on production optimization and operating cost reduction initiatives. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $112 million.

During 2009, $214 million was spent on property acquisitions. Capital expenditures on oil sands projects were $29 million compared with $302 million in 2008.

Husky's high impact exploration program is conducted along the foothills of Alberta and British Columbia and in the deep basin region of Alberta. In 2009, $169 million was invested in drilling in these natural gas prone areas and $63 million was spent on follow-up development including tie-ins, facility installation and development drilling compared with $362 million and $124 million respectively in 2008. During this period, 10 net exploration wells were drilled in the foothills and deep basin regions; 9 net wells were cased as natural gas wells and 1 was cased as a net oil well. The remaining 27 net exploration wells were drilled primarily in the shallow regions of the Western Canada Sedimentary Basin.

The following table discloses Husky's offshore and international drilling activity during 2009:

Offshore and International Drilling Activity			
Canada - East Coast			
Mizzen O-16 Flemish Pass	WI 35%	Stratigraphic test	Exploratory
White Rose J-22-3	WI 72.5%	Gas injection well	Development
United States - Columbia River Basin			
Grey 31-23	WI 50%	Exploration well	Exploratory
South East Asia - China			
QH 29-2-1 Block 39/05	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 3-1-2 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-1-3 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 3-1-4 Block 29/26	WI 100% (1)	Stratigraphic test	Delineation
Liwan 4-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 9-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 9-1-2 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liwan 29-1-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
Liuhua 34-2-1 Block 29/26	WI 100% (1)	Stratigraphic test	Exploratory
South East Asia - Indonesia			
Adiyasa 1	WI 100%	Stratigraphic test	Exploratory
Kukura 1	WI 100%	Stratigraphic test	Exploratory

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

East Coast Development

During 2009, $510 million was invested for East Coast development projects primarily for the North Amethyst and West White Rose satellite tie-back development projects, including drilling operations at North Amethyst and completion of facilities construction and installation. At West White Rose capital expenditures focused on advancing engineering design and planning.

East Coast Exploration

During 2009, Husky spent $64 million primarily on the Mizzen exploration well in the Flemish Pass off the coast of Newfoundland and geological and geophysical data and studies.

Northwest United States

During 2009, Husky spent $25 million on the Gray 31-23 exploration well in the Columbia River Basin in south Washington State that was abandoned after testing non-commercial quantities of natural gas. Husky has a 50% working interest in this exploration well.

Offshore Greenland

During 2009, Husky spent $31 million completing a 2,200 square kilometre 3-D seismic program.

Offshore China and Indonesia

During 2009, $472 million was spent on offshore China projects including the Liwan natural gas discovery delineation program, four exploration wells on the deepwater Block 29/26 and drilling one exploration well on Block 39/05. In Indonesia, capital expenditures during 2009 were $35 million, primarily related to drilling two exploration wells on the East Bawean II PSC.

2010 Upstream Capital Program [1]

(millions of dollars)

Western Canada - oil and gas	$ 1,200
- oil sands	85
East Coast Canada	485
International	660
Total upstream capital expenditures	$ 2,430

[1] *Excludes capitalized administrative costs and capitalized interest.*

The 2010 capital budget has been established with a view to enable Husky to maintain production levels and support its medium and long-term growth strategies. Capital expenditures are focused on those projects offering the highest potential for returns.

Capital expenditures for Western Canada upstream development and exploration will focus on heavy oil properties, enhanced oil recovery projects and unconventional gas holdings. Capital spending on oil sands is primarily focused on development at Sunrise.

Offshore the East Coast of Canada, spending is concentrated on the drilling of development wells at North Amethyst.

In China and Indonesia, capital spending is focused on continuing the development of the Liwan Gas Project and the recently discovered Liuhua gas field, and exploration and development programs offshore China and Indonesia.

3.2 Midstream

Upgrading Net Earnings Summary [1]

(millions of dollars, except where indicated)		Three months ended Dec. 31 2009	Three months ended Dec. 31 2008	Year ended Dec. 31 2009	Year ended Dec. 31 2008
Gross revenues		$ 445	$ 445	$ 1,572	$ 2,435
Gross margin		$ 79	$ 131	$ 296	$ 633
Operating and administration expenses		49	57	188	255
Other (income) expense		-	(2)	(3)	(4)
Depreciation and amortization		9	9	34	31
Income taxes		7	20	23	105
Net earnings		$ 14	$ 47	$ 54	$ 246
Selected operating data:					
Upgrader throughput [2]	*(mbbls/day)*	77.4	75.5	74.1	71.1
Synthetic crude oil sales	*(mbbls/day)*	64.5	58.2	61.8	58.7
Upgrading differential	*($/bbl)*	$ 13.06	$ 27.48	$ 11.89	$ 28.77
Unit margin	*($/bbl)*	$ 13.29	$ 24.60	$ 13.11	$ 29.48
Unit operating cost [3]	*($/bbl)*	$ 6.72	$ 9.85	$ 6.92	$ 10.54

[1] *2008 amounts as restated for adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.*
[2] *Throughput includes diluent returned to the field.*
[3] *Based on throughput.*

The upgrading business segment adds value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The upgrader profitability is primarily dependent on the differential between the cost of heavy crude feedstock and the sales price of synthetic crude oil.

Fourth Quarter

During the fourth quarter of 2009, the upgrading differential averaged $13.06/bbl, a decrease of $14.42/bbl or 52% compared with the fourth quarter of 2008. The differential is equal to Husky Synthetic Blend, which sells at a premium to WTI, less Lloyd Heavy Blend. The overall unit margin was $13.29/bbl in the fourth quarter of 2009 compared with $24.60/bbl during the same period in 2008 primarily as a result of the significantly narrower heavy to light crude oil price difference. This decrease was partially offset by lower unit operating costs in the fourth quarter of 2009 compared with the fourth quarter of 2008 which resulted from lower energy costs.

Twelve Months

Upgrader earnings in 2009 were also impacted by the same factors impacting the fourth quarter. Upgrader throughput in 2009 was 4% higher than 2008 due to increased plant onstream time.

Infrastructure and Marketing Net Earnings Summary

(millions of dollars, except where indicated)			Three months ended Dec. 31 2009	Three months ended Dec. 31 2008	Year ended Dec. 31 2009	Year ended Dec. 31 2008
Gross revenues			**$ 1,692**	$ 2,456	**$ 6,984**	$ 13,544
Gross margin	- pipeline		**$ 26**	$ 19	**$ 106**	$ 120
	- other infrastructure and marketing		**51**	36	**195**	249
			77	55	**301**	369
Operating and administration expenses			**5**	6	**19**	17
Depreciation and amortization			**9**	8	**36**	31
Other (income) expense			**(5)**	1	**(33)**	-
Income taxes			**19**	12	**79**	97
Net earnings			**$ 49**	$ 28	**$ 200**	$ 224
Selected operating data:						
Commodity volumes managed		*(mboe/day)*	**808**	1,064	**912**	1,103
Aggregate pipeline throughput		*(mbbls/day)*	**498**	493	**514**	507

Fourth Quarter

Infrastructure and marketing net earnings in the fourth quarter of 2009 were $49 million compared with $28 million in the fourth quarter of 2008. Increased margins on other infrastructure and marketing were the result of inventory holding gains as a result of rising crude oil prices compared with inventory holding losses in the fourth quarter of 2008 as a result of falling prices. Pipeline margins increased due to increases in net broker margins while volumes remain consistent with the prior year. Other income in the fourth quarter of 2009 includes unrealized gains of $4 million on natural gas storage contracts.

Crude oil and NGL volumes managed have declined due to reduced production at White Rose post turnaround and natural gas volumes managed have declined due to lower drilling and tie-in rates combined with well shut-ins initiated in response to low natural gas prices combined with fewer location trades at Cushing, Oklahoma for Lima refinery feedstock.

Twelve Months

Infrastructure and marketing earnings have decreased in 2009 compared with 2008 due to a reduction in trading activity and lower margins on crude oil, natural gas, and sulphur contracts as a result of lower commodity prices, lower pipeline blending differentials and brokering margins partially offset by inventory holding gains and increases in cogeneration revenues. Other income in 2009 includes unrealized gains of $32 million on natural gas storage contracts as a result of falling natural gas prices.

Midstream Capital Expenditures

Midstream capital expenditures totalled $94 million in 2009. At the Lloydminster upgrader, Husky spent $62 million, primarily for contingent consideration and facility reliability projects. The remaining $32 million was spent on the construction and commissioning of two new tanks at Hardisty, Alberta; the pipeline extension between Lloydminster and Hardisty, Alberta; tankage upgrades at Hardisty and capital enhancements of the cogeneration plants.

3.3 Downstream

Canadian Refined Products Net Earnings Summary [(1)]			Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)			**2009**	2008	**2009**	2008
Gross revenues			**$ 634**	$ 673	**$ 2,495**	$ 3,564
Gross margin	- fuel		**$ 16**	$ 2	**$ 111**	$ 96
	- ethanol		**19**	2	**62**	26
	- ancillary		**13**	9	**53**	42
	- asphalt		**13**	46	**166**	130
			61	59	**392**	294
Operating and administration expenses			**23**	26	**101**	70
Depreciation and amortization			**24**	20	**93**	81
Income taxes			**4**	-	**57**	39
Net earnings			**$ 10**	$ 13	**$ 141**	$ 104
Selected operating data:						
Number of fuel outlets					**482**	492
Light oil sales		*(million litres/day)*	**7.7**	7.5	**7.6**	7.9
Light oil retail sales per outlet		*(thousand litres/day)*	**13.8**	12.7	**13.2**	13.0
Prince George refinery throughput		*(mbbls/day)*	**10.4**	10.7	**10.3**	10.1
Asphalt sales		*(mbbls/day)*	**18.9**	21.4	**22.6**	24.0
Lloydminster refinery throughput		*(mbbls/day)*	**22.2**	28.8	**24.1**	26.1
Ethanol production		*(thousand litres/day)*	**736.4**	661.3	**676.9**	627.2

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 of the Consolidated Financial Statements.

Canadian Refined Products

Fourth Quarter

Gross margin on fuel sales was higher in the fourth quarter of 2009 compared with 2008 due to higher volumes sold in retail outlets combined with improved unit margins. Light oil retail sales were higher due to increased demand as the economy in Western Canada showed signs of recovery compared with a significant drop in demand in the fourth quarter of 2008.

Asphalt gross margins decreased in the fourth quarter of 2009 compared with 2008 as a result of lower volumes combined with lower product margins. In the fourth quarter of 2009, more stable crude feedstock prices resulted in lower margins as a result of the seasonal impact of the end of the summer paving season. In the fourth quarter of 2008, asphalt contracts were based on higher crude prices realized earlier in 2008, however, the price of feedstock declined rapidly offsetting the seasonal impact. Asphalt sales volumes have decreased in the fourth quarter of 2009 compared with the same period in 2008 as production was reduced due to the low netback available for winter sales into the U.S. wholesale market.

The higher ethanol gross margin in the fourth quarter of 2009 was due to higher sales volumes combined with the receipt of funds earned under government incentive programs designed to offset low market prices. These were partially offset by lower sales prices resulting primarily from competition with low priced U.S. imported ethanol. Ethanol production in the fourth quarter of 2009 was 11% higher than in the same period in 2008 due to improved operational performance at the Lloydminster plant.

Operating costs have decreased in the fourth quarter of 2009 compared with the same period in 2008 due primarily to lower energy costs.

Included in ethanol gross margin in the fourth quarter of 2009 is $13 million related to government assistance grants received compared with $6 million received in 2008.

Twelve Months

During 2009, refined products earnings increased by $37 million compared with 2008. In addition to the factors that affected the fourth quarter of 2009, asphalt margins realized earlier in the year were higher than the same period in 2008 due to lower feedstock costs in 2009.

Operating and administration expenses in 2008 included a $15 million credit resulting from an insurance settlement. The remaining increases are primarily due to higher repair and maintenance costs and property taxes.

Included in ethanol gross margin in 2009 is $53 million related to government assistance grants received compared with $18 million received in 2008.

U.S. Refining and Marketing Net Earnings Summary [(1)]

(millions of dollars, except where indicated)		Three months ended Dec. 31 2009	Three months ended Dec. 31 2008	Year ended Dec. 31 2009	Year ended Dec. 31 2008
Gross revenues		$ 1,169	$ 1,474	$ 5,349	$ 7,802
Gross refining margin		$ 80	$ (648)	$ 852	$ (58)
Processing costs		101	147	423	417
Operating and administration expenses		-	(4)	7	3
Interest - net		1	1	3	3
Depreciation and amortization		47	50	194	154
Other (income) expense		(1)	-	30	-
Income taxes		(25)	(307)	71	(232)
Net earnings (loss)		$ (43)	$ (535)	$ 124	$ (403)
Selected operating data:					
Lima Refinery throughput	*(mbbls/day)*	54.8	127.6	114.6	136.6
Toledo Refinery throughput	*(mbbls/day)*	67.5	61.9	64.9	60.6 [(2)]
Refining margin	*($/bbl crude throughput)*	$ 7.16	$ (37.17)	$ 13.12	$ (0.88)
Refinery feedstocks and refined products inventory	*(mmbbls)*	12.3	11.9	12.3	11.9

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.
(2) The Toledo Refinery operating results are included from March 31, 2008, the date the acquisition was completed. Throughput represents nine months of operations.

U.S. Refining and Marketing

On March 31, 2008, Husky completed a transaction that resulted in the formation of two joint venture entities forming an integrated oil sands business and a refining joint venture. Husky holds a 50% interest in the BP-Husky Toledo Refinery. Net earnings for 2009 include both the Lima and Toledo refineries whereas the comparative period in 2008 only includes the results from the Toledo Refinery for nine months.

Fourth Quarter

U.S. Refining and Marketing earnings have increased in the fourth quarter of 2009 compared with the fourth quarter of 2008 as a result of improved product margins offsetting reduced sales volumes. Margins in the fourth quarter of 2008 were dramatically impacted by rapidly falling crude oil prices which resulted in significant inventory write downs. The Lima Refinery was shut down on October 2, 2009 for a scheduled major turnaround and maintenance work and resumed production on November 20, 2009.

Other income in the fourth quarter of 2009 includes $1 million of unrealized gains on forward contracts for feedstock purchases.

Twelve Months

Higher refinery throughput at Toledo in 2009 compared with 2008 was the result of improved turnaround efficiency and generally stable operations throughout the year. At Lima, throughput was lower in 2009 compared with 2008 due to the scheduled major turnaround in the fourth quarter.

Refining margins realized in 2009 reflect the positive benefit of consuming feedstock purchased one to two months prior to production in a rising crude oil price environment compared to the negative impact of falling crude oil prices in late 2008.

Other expenses in 2009 include $30 million of realized losses on forward contracts for feedstock purchases.

Downstream Capital Expenditures

Downstream capital expenditures totalled $341 million for 2009.

In Canada, capital expenditures totalled $81 million primarily for upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $260 million. At the Lima Refinery, $136 million was spent on various debottleneck projects, optimizations and environmental initiatives and $69 million was spent on the scheduled major turnaround. At the BP-Husky Toledo Refinery, capital expenditures totalled $55 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection.

3.4 Corporate

Corporate Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars) income (expense)	**2009**	2008	**2009**	2008
Intersegment eliminations - net	**$ (3)**	$ 75	**$ (44)**	$ 61
Administration expense	**(24)**	(27)	**(69)**	(95)
Other income (expense)	**12**	38	**(1)**	48
Stock-based compensation	**-**	60	**(1)**	33
Depreciation and amortization	**(15)**	(8)	**(51)**	(30)
Interest - net	**(52)**	(30)	**(191)**	(144)
Foreign exchange	**6**	275	**5**	335
Income taxes	**32**	(47)	**136**	(5)
Net earnings (loss)	**$ (44)**	$ 336	**$ (216)**	$ 203

Fourth Quarter

The corporate segment reported a loss of $44 million in the fourth quarter of 2009 compared with earnings of $336 million in the fourth quarter of 2008. Foreign exchange gains decreased by $269 million mainly as a result of the relatively stable U.S./Canadian exchange rate in the fourth quarter of 2009 compared with the same period in 2008. The decrease in stock-based compensation recoveries in the fourth quarter is due to the relatively flat share price in 2009 compared with the same period in 2008.

Net interest expense increased in the fourth quarter primarily due to higher debt levels compared to the same period in 2008.

Administration expense has decreased from the fourth quarter of 2008 due to cost reduction initiatives. The increase in depreciation and amortization was a result of adjustments to the book value of legacy sites that have been deemed inactive. Other income was impacted by lower unrealized gains on forward purchase contracts in the fourth quarter of 2009 compared to the same period of 2008.

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

Twelve months

In addition to the same factors that impacted the fourth quarter, the corporate segment was impacted by additional insurance costs of $5 million and realized losses on forward purchases of U.S. dollars of $9 million compared to unrealized gains on forward purchases of U.S. dollars of $52 million in 2008.

Foreign Exchange Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2009**	2008	**2009**	2008
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ (61)**	$ 148	**$ (327)**	$ 217
(Gain) loss on cross currency swaps	**8**	(58)	**62**	(83)
(Gain) loss on contribution receivable	**32**	(191)	**216**	(228)
Other (gains) losses	**15**	(174)	**44**	(241)
Foreign exchange (gain) loss	**$ (6)**	$ (275)	**$ (5)**	$ (335)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.933**	U.S. $0.944	**U.S. $0.817**	U.S. $1.012
At end of period	**U.S. $0.956**	U.S. $0.817	**U.S. $0.956**	U.S. $0.817

Corporate Capital Expenditures

For 2009, corporate capital expenditures of $36 million were primarily for computer hardware and software, office furniture, renovations and equipment and system upgrades.

Consolidated Income Taxes

During the fourth quarter of 2009, consolidated income taxes were $116 million expense compared with $124 million recovery in 2008. Consolidated taxes in the fourth quarter of 2008 include recoveries on U.S. losses in respect of U.S. Refining and Marketing and recognition of a future income tax asset related to Upstream projects. Consolidated income taxes for 2009 were $541 million compared with $1,394 million in 2008 due to lower earnings in 2009 compared with 2008.

Cash taxes paid in 2009 were $1,323 million, of which $615 million relates to final instalments paid in respect of 2007 earnings, included in current liabilities at December 31, 2008, and $708 million relating to instalments paid in respect of 2008 earnings. Further cash tax instalments in respect of 2008 earnings are estimated to be approximately $530 million in the first quarter of 2010 and are included in current liabilities at December 31, 2009.

4. Liquidity and Capital Resources

In the fourth quarter and year ended 2009, Husky funded its capital programs and dividend payments by cash generated from operating activities, cash on hand and long term debt issuance. Husky maintained its strong financial position with debt of $3,229 million partially offset by cash on hand of $392 million for $2,837 million of net debt. Husky has no long-term debt maturing until 2012. At December 31, 2009, the Company had $1.5 billion in unused committed credit facilities, $154 million in unused short-term uncommitted credit facilities and unused capacity under the new debt shelf prospectuses filed in Canada and the U.S. of $1 billion and U.S. $1.5 billion, respectively. (Refer to Section 4.4).

Cash Flow Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except ratios)	**2009**	2008	**2009**	2008
Cash flow - operating activities [(1)]	**$ 376**	$ 1,421	**$ 1,918**	$ 6,778
- financing activities	**$ (295)**	$ (490)	**$ 594**	$ (2,559)
- investing activities [(1)]	**$ (935)**	$ (984)	**$ (3,033)**	$ (3,514)
Financial Ratios				
Debt to capital employed *(percent)*			**18.3**	12.0
Debt to cash flow *(times)* [(2)]			**1.3**	0.3
Corporate reinvestment ratio *(percent)* [(2) (3)]			**111**	66
Interest coverage ratios on long-term debt only[(4)]:				
Earnings			**11.1**	34.4
Cash flow			**17.4**	50.9
Interest coverage ratios on total debt[(5)]:				
Earnings			**10.7**	33.4
Cash flow			**16.7**	49.3

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.
(2) Calculated for the 12 months ended for the dates shown.
(3) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.
(4) Interest coverage on long-term debt on an earnings basis is equal to earnings before interest expense on long-term debt and income taxes divided by interest expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before interest expense on long-term debt and current income taxes divided by interest expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.
(5) Interest coverage on total debt on an earnings basis is equal to earnings before interest expense on total debt and income taxes divided by interest expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before interest expense on total debt and current incomes taxes divided by interest expense on total debt and capitalized interest. Total debt includes short and long-term debt.

4.1 Operating Activities

Fourth Quarter

In the fourth quarter of 2009, cash generated from operating activities amounted to $376 million compared with $1,421 million in the fourth quarter of 2008. Lower cash flow from operating activities was primarily due to lower gas prices and lower crude oil and natural gas production, combined with a stronger Canadian dollar relative to the U.S. dollar.

Twelve Months

Cash generated from operating activities totalled $1,918 million in 2009 compared with $6,778 million in 2008. Lower cash flow from operating activities was primarily due to lower commodity prices, lower crude oil and natural gas production and the payment of current income taxes in 2009 related to 2008 and 2007 earnings, partially offset by a weaker Canadian dollar relative to the U.S. dollar.

4.2 Financing Activities

Fourth Quarter

In the fourth quarter of 2009, cash used in financing activities was $295 million compared with $490 million in the fourth quarter of 2008, primarily used for the payment of dividends on common shares. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

Twelve Months

Cash provided by financing activities was $594 million in 2009 compared with cash used in financing activities of $2,559 million in 2008. In 2008, bridge financing related to the Lima acquisition was repaid. In May 2009, the Company issued U.S. $1.5 billion in long-term bonds.

4.3 Investing Activities

Fourth Quarter

In the fourth quarter of 2009, cash used in investing activities amounted to $935 million compared with $984 million in the fourth quarter of 2008. Cash invested in both periods was used primarily for capital expenditures and acquisitions.

Twelve Months

Cash used in investing activities was $3.0 billion for 2009 compared with $3.5 billion in 2008. Cash invested in both periods was used primarily for capital expenditures and acquisitions.

4.4 Sources of Capital

Husky is currently able to fund its capital programs, non-cancellable contractual obligations and other commercial commitments principally by cash generated from operating activities, the issuance of long-term debt and committed credit facilities. The Company also maintains access to sufficient capital via debt markets commensurate with the strength of 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, 2009, working capital was $726 million compared with $404 million at December 31, 2008.

At December 31, 2009, Husky had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. A total of $133 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009. The shelf prospectus enables Husky to offer up to U.S. $3 billion of debt securities in the United States until March 26, 2011. During the 25-month period that the shelf prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of December 31, 2009, U.S. $750 million of 5.90% notes due June 15, 2014 and U.S. $750 million of 7.25% notes due December 15, 2019 had been issued under this shelf prospectus. On December 21, 2009, Husky filed an additional debt shelf prospectus with the Alberta Securities Commission that enables Husky to offer up to $1 billion of medium-term notes in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, medium-term notes may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of December 31, 2009, no medium-term notes had been issued under this shelf prospectus. (Refer to Note 7 to the Consolidated Financial Statements).

Capital Structure	Dec. 31, 2009	
(millions of dollars)	Outstanding	Available
Total short-term and long-term debt	$ 3,229	$ 1,662
Common shares, retained earnings and accumulated other comprehensive income	$ 14,413	

4.5 Credit Ratings

Husky's credit ratings are available in its Annual Information Form at www.sedar.com.

4.6 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.

Contractual Obligations

Payments due by period ($ millions)	2010	2011-2012	2013-2014	Thereafter	Total
Long-term debt and interest on fixed rate debt	$ 211	$ 827	$ 1,130	$ 3,093	$ 5,261
Operating leases	102	170	123	162	557
Firm transportation agreements	188	290	254	1,413	2,145
Unconditional purchase obligations (1)	2,701	2,317	54	106	5,178
Lease rentals and exploration work agreements	98	242	285	462	1,087
Asset retirement obligations (2)	29	66	60	5,725	5,880
	$ 3,329	$ 3,912	$ 1,906	$ 10,961	$ 20,108

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services, natural gas purchases and the retail outlets acquisition.*

(2) *Asset retirement obligations – amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

The Terra Nova oil field is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Husky currently holds a combined 12.51% working interest in the field, subject to redetermination. The process of working interest redetermination is before an arbitrator who is expected to make a decision by the third quarter of 2010. The outcome and impact of the arbitration process is not reasonably determinable at this time.

4.7 Off Balance Sheet Arrangements

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

Husky has chosen not to renew the securitization agreement which expired on March 31, 2009.

4.8 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. $1.5 billion 5- and 10-year senior notes issued through the existing base shelf prospectus, which was filed in February 2009. (Refer to Note 7 to the Consolidated Financial Statements). Subsequent to this offering, U.S. $22 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. The coupon rates offered were 5.90% and 7.25% for the 5- and 10-year tranches respectively. These transactions were measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At December 31, 2009, the senior notes were included in long-term debt on the Company's balance sheet.

5. Capability to Deliver Results and the Strategic Plan

Husky's capacity to deliver results and the strategic plan are described in the Company's annual MD&A and also in its Annual Information Form that are available from www.sedar.com and www.sec.gov.

In summary, Husky's current strategy is to continue to exploit oil and gas assets in Western Canada while expanding into new areas with large scale sustainable growth potential. The Company's plans include projects in Canada (the Alberta oil sands and the basins offshore Canada's East Coast), Asia (the South China Sea, the Madura Strait and the East Java Sea), the U.S. Columbia River Basin and offshore Greenland. In the midstream and downstream sectors, Husky is enhancing performance and maximizing the value chain through integrating its businesses, optimizing plant operations and expanding plant and infrastructure.

6. Key Growth Highlights

The 2009 capital program was focused mainly on optimizing upstream production, midstream and downstream development and progressing major projects offshore Canada's East Coast and South East Asia. The 2010 capital budget has been established with a view to maintaining the strength of Husky's balance sheet and take advantage of opportunities as economic conditions begin to improve and financial uncertainty abates. Capital expenditures will be focused on those projects offering the highest potential for returns and mid to long-term growth.

Upstream

East Coast Canada and Greenland

White Rose Development Projects

At the North Amethyst oil field, subsea installation and commissioning were completed and development drilling resumed in November, 2009. The initial production well and water injection well are expected to be completed and tested during the first quarter of 2010. Production from North Amethyst is targeted to come on stream early in the second quarter of 2010.

In 2008, drilling results from the North Amethyst E-17 well that was drilled to the deeper Hibernia formation revealed 55 metres of net oil-bearing reservoir. In 2010, the resources of the Hibernia formation will be assessed by reservoir studies and future drilling at both the North Amethyst and White Rose fields.

In November 2009, Husky filed an amended development plan with the Canada-Newfoundland and Labrador Offshore Petroleum Board for a two well pilot scheme at the West White Rose field. The proposed staged development plan for West White Rose would initially start with one production well and one water injection well drilled from the existing central drill centre at the main White Rose field. It is expected that this well pair would provide data pertinent to the next phases of the West White Rose development. Subject to receipt of the West White Rose development plan amendment approval, drilling could commence as early as the second quarter of 2010 with completion and first oil by late 2010/early 2011.

East Coast Canada Exploration

In November 2009, Husky was successful on a bid for the NL09-01 parcel in the Jeanne d'Arc Basin. This parcel consists of approximately 23,600 acres adjacent to the North Amethyst field. Husky is the operator and holds a 72.5% interest in this exploration prospect.

Husky continues to evaluate the results of its 2008 2,150 square kilometre 3-D seismic program acquired in the Jeanne d'Arc Basin with a view towards identifying one or two exploratory well locations in the near-term. During the fourth quarter, the Company continued public consultations on its Environmental Assessment ("EA") process for future seismic activity offshore Labrador and commenced the EA process for potential seismic acquisition in the Sydney Basin, located between Newfoundland and Cape Breton, Nova Scotia. The programs are planned for the summer/fall of 2010.

Application was made in November 2008 for a significant discovery licence based on the results of the December 2008 Mizzen exploration well. Husky has a 35% working interest in the Mizzen well located in the Flemish Pass Basin on Exploration Licence 1049. Husky anticipates that the licence will be granted in February/March of 2010.

Offshore Greenland

Evaluation of a 7,000 kilometre 2-D seismic program acquired in the third quarter of 2008 on Blocks 5 and 7 is complete. Evaluation of an airborne gravity and magnetics survey that was acquired in the second quarter of 2009 is nearing completion. Husky is the operator and holds an 87.5% interest in these two blocks. Husky also holds a 43.75% working interest in Block 6 where 3,000 kilometres of 2-D seismic was acquired in the third quarter of 2008. In November 2009, Husky completed the acquisition of a 2,200 square kilometre 3-D seismic program over Block 7 and Block 5. This survey is the first 3-D seismic survey conducted offshore Greenland and utilizes a new "Geostreamer" technology.

South East Asia

Offshore China Liwan Delineation

The Liwan 3-1 natural gas field, which is located approximately 300 kilometres southeast of Hong Kong, will use a subsea production system connected to a central shallow water platform by flow lines. The platform will be connected by pipeline to an onshore gas plant with access to the energy markets of Hong Kong and Guangdong province on the China mainland. Husky and development partner, China National Offshore Oil Corporation ("CNOOC"), have established a joint marketing group for the sale of Liwan 3-1 natural gas and associated natural gas liquids.

The Liuhua 34-2 field will be tied into the proposed Liwan 3-1 shallow water infrastructure.

The Liwan 3-1 is the first deepwater development offshore project in China. Following field delineation of the Liwan 3-1 natural gas field, Husky submitted the Original Gas In-Place report to the Government of China in late December and expects to receive approval in early 2010. The Overall Development Plan, is currently being prepared with the aim of submitting to the Government of China in the first quarter of 2010. FEED commenced in the second quarter and was approximately 96% complete at the end of 2009 and is expected to be completed by mid 2010. First production is expected in 2013.

In November 2009, the *West Hercules* drilled a significant new natural gas discovery at Liuhua 34-2-1, approximately 20 kilometres to the northeast of the Liwan 3-1 field. The well tested natural gas with a high liquids content at an equipment restricted rate of 55 mmcf/day, with indications that future well deliveries could exceed 140 mmcf/day. In December 2009, the *West Hercules* drilled the Liwan 9-1-2 exploration well, which was abandoned without testing. The *West Hercules* is currently drilling the Liwan 29-1-1 exploration well, following which the rig will return to the Liuhua 34-2 discovery and begin delineation drilling.

Offshore China Exploration

Planning is underway for an exploration well on Block 04/35 in the East China Sea. A rig has been secured and the well is expected to be spud in early 2010. On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, existing 2-D seismic has been interpreted and plans are in place to acquire 300 square kilometres of 3-D seismic in the March/April 2010 time frame.

During the fourth quarter of 2009, regulatory approval was obtained to relinquish deepwater Block 29/06 in the Pearl River Mouth Basin, immediately to the east of Block 29/26 together with Blocks 35/18 and 50/14 in the Yinggehai Basin due to higher than acceptable exploration risk.

Indonesia Exploration and Development

The Madura BD field development plan has been approved by the Government of Indonesia and Husky, together with the operator CNOOC, continue to await approval of an extension to the PSC. Engineering work has been tendered and commenced.

During the fourth quarter of 2009, contracts were awarded for the acquisition and processing of 1,020 kilometres of new 2-D seismic on the North Sumbawa II Block. This data was acquired in December 2009 and will be used to define exploration prospects that are planned for drilling in 2011.

Husky holds a 100% interest in the North Sumbawa II Block, comprising 5,000 square kilometres in the East Java Sea.

In the East Bawean II PSC an application was made to relinquish the block. The application was based on the drilling of two exploration wells, which were abandoned without testing in the third quarter of 2009, and a lack of any other attractive prospects on the block.

Heavy Oil and Oil Sands

Sunrise Oil Sands Integrated Project

Husky and BP continue to advance the development of the Sunrise project in multiple stages (Husky 50% interest). Bitumen production from phase one (planned at 60 mbbls/day) is expected to commence approximately four years after project sanction planned in 2010 and total gross production is currently planned to increase to 200 mbbls/day, subject to project sanction and market conditions. Work on optimization to simplify its scope was completed at the end of 2009. With FEED completed and regulatory approval for the amended design in place, Husky is preparing to issue requests for proposals for the central plant and field facilities. The development of the Sunrise Oil Sands Project is strategically linked to the repositioning project at the Toledo Refinery.

Tucker Oil Sands Project

Husky continues to pursue operational strategies to achieve full implementation of the SAGD process in this reservoir. The majority of the wells in the project are in steady state SAGD operational mode and production rates were approximately 5 mbbls/day at the end of the year. Drilling of three new well pairs commenced in December 2009 and are expected to be injecting steam by the third quarter of 2010. Regulatory applications are proceeding for additional drilling in 2010.

McMullen

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production project and plans for a thermal pilot project. During December, Husky completed and tied in a 13 well program at the cold production project. An additional 13 wells were drilled in November and December and are being completed and equipped for start-up in February 2010.

Non-Thermal Enhanced Oil Recovery

In the Lloydminster heavy oil producing area, Husky continues to test various non-thermal enhanced recovery techniques. Operations continue at the Company's first cold enhanced pilot project where six successful injection/production cycles have been completed. Husky's second pilot project, which utilizes CO_2, continued to operate to the end of 2009 with promising initial results. Both pilots continue to provide insight into reservoir response and process economics.

Western Canada (excluding Oil Sands)

Northeast British Columbia Shale Gas

In October 2009, Husky acquired a 50% working interest in 36 drilling spacing units (640 acres) with rights in the Doig and Montney formations. With this acquisition Husky's combined holdings total approximately 25,000 acres in this resource play located in the Cypress area of Northeast British Columbia, which is largely characterized by shale gas reservoirs. Husky is currently participating in a horizontal exploration well on an adjacent section and further drilling is contingent on the results of this well.

Coal Bed Methane

During 2009, Husky tied in 55 gross (27.5 net) coal bed methane producing wells in the Elnora/Trocho area. Husky intends to continue with its coal bed methane program into 2010 with plans to tie-in 8 gross wells (4 net) drilled in the fourth quarter, and recomplete 15 gross (7.5 net) shut-in conventional natural gas wells in the Horseshoe Canyon coal formation.

Northeastern British Columbia Conventional Exploration

In the Bullmoose – Sukunka region of Northeastern British Columbia, Husky is participating in the Belcourt formation exploration well (42% WI) that will follow-up the Burnt River c-A61-A (55% WI) and the Sukunka a-27-F (20% WI) wells, which are capable of producing at rates in excess of 30 mmcf/day. Both the Burnt River and Sukunka wells were placed on production in early October at a combined 15 to 25 mmcf/d net Husky raw gas rate depending on processing capacity availability.

Gas Resource Plays

Husky has increased its exposure to gas resource plays within the Western Canada Basin that have the potential to deliver significant volumes of low cost gas in the coming years. Husky currently has over 925,000 acres associated with several gas resource projects in various stages of evaluation and development. These include established assets at Bivouac (625,000 acres) and Ansell (115,000 acres) in addition to a number of emerging projects including the Montney (Cypress) and the Horn River Basin. In 2009, Husky added over 89,000 acres of new lands to its gas resource play portfolio.

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") enhanced oil recovery program which currently includes ASP developments at Fosterton and Bone Creek, Saskatchewan and operating ASP projects at Gull Lake, Saskatchewan and Warner and Crowsnest, Alberta. In addition, Husky holds a 20.3% non-operating working interest in the Instow, Saskatchewan ASP flood, in which oil response continues to increase in line with expectations. The Warner chemical injection has been increased following the successful drilling of two infill wells in the fourth quarter. The polymer injection is expected to continue through to 2012. Husky completed the Alkaline Surfactant (AS) portion of the injection scheme at the Crowsnest project in December 2009. Incremental recovery continues to increase according to plan at both floods. At Gull Lake, the project was completed on schedule. Surfactant was added to the injected fluids effective December 1, 2009 and the facility is pumping at full capacity. The Fosterton ASP reservoir and detailed facility design is near completion. Upon project approval, the facility long lead equipment will be ordered in 2010. Facility construction will commence in early 2011 with an expected start up in late 2011. Husky is the operator and holds a 62.4% working interest in this project.

United States

Husky is currently evaluating its Columbia River Basin holding in excess of 1.7 million gross acres of largely gas prone tight sandstone reservoirs. The results of the Grey 31-23 well, which was drilled in 2009, will be incorporated into this study. Husky holds up to a 50% working interest in this area.

Midstream

Husky completed construction and commissioning of two 300,000 barrel tanks at Hardisty. Husky also completed connections from the Hardisty terminal to the new Keystone pipeline.

Downstream

Lima, Ohio Refinery

Husky has proposed a reconfiguration of the Lima Refinery that is intended to increase processing capacity of heavier, less costly, crude oil feedstock to enhance margins and increase flexibility in product outputs. An engineering evaluation has been completed and the project is currently on hold pending an improvement in the light/heavy crude oil differential. Implementation of this project on a phased basis is being evaluated to maximize capital spending efficiency and provide a hedge against uncertain market conditions. As proposed, the project would increase capacity to 170 mbbls/day crude charge, 105 mbbls/day of which would be heavy crude oil.

Toledo, Ohio Refinery

Husky and its partner, BP, have announced the sanction of the Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio refinery. The project will improve the efficiency and competitiveness of the refinery by reducing energy consumption and lowering operating costs with the replacement of two naphtha reformers and one hydrogen plant with one 42,000 bbls/day continuous catalyst regeneration reformer system plant.

A project team has also been launched to reposition the refinery to process bitumen from the first two phases of the Sunrise oil sands integrated project. Due to the integrated nature of this project, progress will coincide with the upstream development requirements. The refinery continues to advance a multi-year program to improve operational integrity and plant performance and reduce operating costs and environmental impacts.

Retail

In December 2009, Husky entered into an agreement to purchase 98 retail outlets in the southern Ontario region. Transfer of these outlets to Husky will begin in the first quarter of 2010.

7. Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks see the Company's 2008 Annual Information Form filed on the Canadian Securities Administrator's web site, *www.sedar.com*, the Securities and Exchange Commission's web site, *www.sec.gov* or Husky's web site *www.huskyenergy.com*.

Husky is exposed to risk factors associated with operating in developing countries, political and regulatory instability. The Company maintains close contact with governments in the areas within which it operates.

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

In June 2009, the United States House of Representatives passed the Waxman-Markey American Clean Energy and Security Act, which requires a 17% reduction of greenhouse gas emissions from 2005 levels by 2020 and an 80% reduction by 2050. The bill also sets a system of permitting under which regulated industries would need to acquire sufficient permits for their emissions. In September 2009 the Kerry-Boxer Clean Energy Jobs and American Power Act, which increases the required reduction of greenhouse gases to 20% by 2020, was introduced in the United States Senate. The proposed bill requires further legislative approvals before becoming law and its scope and requirements could be changed through this process before receiving final approval. Husky's operations may be impacted by this legislation, which commencing in 2013 would require U.S. refining operations to significantly reduce emissions and/or purchase permits, which may increase capital and operating expenditures.

Interest Rate Risk Management

In 2009, interest rate risk management activities resulted in a decrease to interest expense of less than $1 million.

At December 31, 2009, Husky had the following interest rate swaps in place:

- U.S. $100 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for LIBOR + 420 bps until November 15, 2016.
- U.S. $275 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for LIBOR + 265 bps blended until September 15, 2017.

During 2009, these swaps resulted in an offset to interest expense amounting to less than $1 million.

Husky also had interest rate swaps on $200 million of long-term debt effective February 8, 2002 whereby 6.95% was swapped for CDOR + 175 bps that expired on July 14, 2009. In 2008, the interest rate swaps were discontinued as a fair value hedge as the $200 million medium-term notes were redeemed. During 2009, a loss of less than $1 million was recognized in other expenses on the Consolidated Statements of Earnings and Comprehensive Income.

The amortization of previous interest rate swap terminations resulted in an additional $3 million offset to interest expense in 2009.

Cross currency swaps resulted in an addition to interest expense of $4 million in 2009.

Foreign Currency Risk Management

At December 31 2009, Husky had the following cross currency debt swaps in place:

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

At December 31, 2009, the cost of a U.S. dollar in Canadian currency was $1.0466.

During 2009, the Company settled its two remaining forward purchases of U.S. dollars realizing a loss of $9 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Husky's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities.

In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense.

At December 31, 2009, 100% or $3.2 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 88% when the cross currency swaps are considered.

Effective July 1, 2007, the Company's U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. During 2008, the Company repaid U.S. $750 million of bridge financing and repurchased U.S. $63 million of bonds that were classified as a net investment hedge. For 2009, the unrealized foreign exchange gain arising from the translation of the debt was $104 million, net of tax expense of $18 million, which was recorded in Other Comprehensive Income.

Effective December 3, 2009, Husky designated U.S. $300 million of the U.S. $750 million senior notes due December 15, 2019 as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. For 2009, unrealized foreign exchange gains arising from the translation of the debt were less than $1 million net of tax, which was recorded in Other Comprehensive Income.

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, 2009, Husky's share of this receivable was U.S. $1.2 billion including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in Other Comprehensive Income as this item relates to a self-sustaining foreign operation. At December 31, 2009, Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

8. Critical Accounting Estimates

Certain of Husky's accounting policies require that it makes appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. For a discussion about those accounting policies, please refer to Husky's Management's Discussion and Analysis for the year ended December 31, 2008 available at *www.sedar.com*.

9. Accounting Policies

New Accounting Standards Adopted

As disclosed in Management's Discussion and Analysis for the year ended December 31, 2008, on January 1, 2009, Husky retroactively adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064, "Goodwill and Intangible Assets," which replaced CICA Section 3062 of the same name. As a result of issuing this guidance, CICA Section 3450, "Research and Development Costs," and Emerging Issues Committee ("EIC") Abstract No. 27, "Revenues and Expenditures during the Pre-operating Period," have been withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with CICA Section 1000, "Financial Statement Concepts."

Section 3064 has eliminated the practice of recognizing items as assets that do not meet the Section 1000 definition and recognition criteria. Under this new guidance, fewer items meet the criteria for capitalization. The adoption of this standard has resulted in a reduction of retained earnings at January 1, 2009 of $25 million, a reduction to assets of $36 million and a reduction to the future income tax liability of $11 million.

Effective July 1, 2009, the Company prospectively adopted the CICA amendments to Section 3855, "Financial Instruments – Recognition and Measurement." Amendments to this section have prohibited the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured. The adoption of the amendments to this standard did not have an impact on the Company's financial statements.

Effective September 30, 2009, the Company adopted the CICA amendments to Section 3855, "Financial Instruments – Recognition and Measurement," in relation to the impairment of financial assets. Amendments to this section have revised the definition of "loans and receivables" and provided that certain conditions have been met, permits reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. These amendments are effective for the Company's annual financial statements relating to its fiscal year beginning on January 1, 2009. The adoption of the amendments to this standard did not have an impact on the Company's financial statements.

Effective December 31, 2009, the Company adopted the CICA amendments to Section 3862, "Financial Instruments–Disclosures," to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities 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. The adoption of the amendments to this standard results in increased note disclosures for financial instruments.

Recent Accounting Pronouncements

In January 2009, the CICA issued Section 1582, "Business Combinations," which will replace CICA Section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price.

Contingent liabilities are to be recognized at fair value at the acquisition date and re-measured at fair value through earnings each period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 is effective for Husky on January 1, 2011 with prospective application and early adoption permitted.

In January 2009, the CICA issued Section 1601, "Consolidated Financial Statements," which will replace CICA Section 1600 of the same name. This guidance requires uniform accounting policies to be consistent throughout all consolidated entities and the difference between reporting dates of a parent and a subsidiary to be no longer than three months. These are not explicitly required under the current standard. Section 1601 is effective for Husky on January 1, 2011 with early adoption permitted. This standard will have no impact to the Company.

In January 2009, the CICA issued Section 1602, "Non-controlling Interests," which will replace CICA Section 1600, "Consolidated Financial Statements." Minority interest is now referred to as non-controlling interest, ("NCI"), and is presented within equity. Under this new guidance, when there is a loss or gain of control the Company's previously held interest is revalued at fair value. Currently an increase in an investment is accounted for using the purchase method and a decrease in an investment is accounted for as a sale resulting in a gain or loss in earnings. In addition, NCI may be reported at fair value or at the proportionate share of the fair value of the acquired net assets and allocation of the net income to the NCI will be on this basis. Currently, NCI is recorded at the carrying amount and can only be in a deficit position if the NCI has an obligation to fund the losses. Section 1602 is effective for Husky on January 1, 2011 with early adoption permitted.

International Financial Reporting Standards

In January 2006, the Canadian Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. In February 2008, as part of its strategic plan, the AcSB confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian GAAP for years beginning on or after January 1, 2011. An omnibus exposure draft was issued by the AcSB in the second quarter of 2008, which incorporates IFRS into the CICA Handbook and prescribes the transitional provisions for adopting IFRS. In March 2009, the AcSB issued a second omnibus exposure draft on the adoption of IFRS. This exposure draft confirms the IFRS transition date as January 1, 2011 for all Canadian publicly accountable enterprises, incorporates any changes to IFRS since the previous exposure draft was issued and discusses additional key transitional issues. In October 2009, the AcSB issued a third omnibus exposure draft on the adoption of IFRS. This exposure draft incorporates changes to IFRS since the previous exposure draft that will be applicable to Canadian entities.

In July 2009, the International Accounting Standards Board ("IASB") approved additional IFRS transitional exemptions that will allow entities to allocate their oil and gas asset balances as determined under full cost accounting to the IFRS categories of exploration and evaluation assets and development and producing properties. This exemption will relieve entities from significant adjustments resulting from retrospective adoption of IFRS. The Company intends to utilize this exemption. In addition, the Company is monitoring the IASB's active projects and all changes to IFRS prior to January 1, 2011 will be incorporated as required.

The Company commenced its IFRS transition project in 2008, which includes four key phases: project engagement, policy diagnostic, solution development and implementation.

The Company has completed the diagnostic assessment phase and has determined that the most significant impact of IFRS conversion is to property, plant and equipment. IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase. The Company currently follows full cost accounting as prescribed in Accounting Guideline ("AcG") 16, "Oil and Gas Accounting – Full Cost." Conversion to IFRS may have a significant impact on how the Company accounts for costs pertaining to oil and gas activities, in particular those related to the pre-exploration and development phases. In addition, the level at which impairment tests are performed and the impairment testing methodology will differ under IFRS.

The IFRS conversion will also result in other impacts, some of which may be significant in nature. Assessments of other impacts completed to date include foreign exchange, revenue recognition, provisions and asset retirement obligations. Husky is also evaluating other first-time adoption exemptions available upon initial transition that give relief from retrospective application of IFRS.

During the fourth quarter of 2009, the Company continued to progress through the implementation phase of its project and is working on the development of processes and systems to position itself for reporting under IFRS in 2011.

At this time, the impact on the Company's financial position and results of operations is not reasonably determinable or estimable.

10. Reader Advisories

This interim report should be read in conjunction with the Consolidated Financial Statements and related Notes.

Readers are encouraged to refer to Husky's MD&A and Consolidated Financial Statements and 2008 Annual Information Form filed in 2009 with Canadian regulatory agencies and 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, 2009 are compared with results for the three months ended December 31, 2008 and results for the twelve months ended December 31, 2009 are compared with results for the twelve months ended December 31, 2008. Discussions with respect to Husky's financial position as at December 31, 2009 are compared with its financial position at December 31, 2008.

Additional Reader Guidance

- The Consolidated Financial Statements and comparative financial information included in this interim report have been prepared in accordance with Canadian GAAP.
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.

Non-GAAP Measures

Disclosure of Cash Flow from Operations

This interim report contains the term "cash flow from operations," which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with GAAP, as an indicator of Husky's financial performance. Cash flow from operations or earnings is presented in Husky's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income 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	
(millions of dollars)		**2009**	2008[(1)]	**2009**	2008 [(1)]
Non-GAAP	Cash flow from operations	**$ 657**	$ 330	**$ 2,507**	$ 5,946
	Settlement of asset retirement obligations	**(17)**	(19)	**(41)**	(56)
	Change in non-cash working capital	**(264)**	1,110	**(548)**	888
GAAP	Cash flow - operating activities	**$ 376**	$ 1,421	**$ 1,918**	$ 6,778

[(1)] 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.

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. 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	
(millions of dollars)		**2009**	2008 [(1)]	**2009**	2008 [(1)]
GAAP	Net earnings	**$ 320**	$ 231	**$ 1,416**	$ 3,751
	Net foreign exchange	**(7)**	(214)	**(15)**	(255)
	Net financial instruments	**(3)**	3	**5**	19
	Net stock-based compensation	**-**	(42)	**1**	(23)
	Net inventory write-downs	**24**	382	**68**	461
	Sale of 50% of Husky Oil (Madura) Limited to CNOOC Ltd.	**-**	-	**-**	(69)
Non-GAAP	Adjusted net earnings	**$ 334**	$ 360	**$ 1,475**	$ 3,884

(1) 2008 amounts as restated for the adoption of a new accounting policy. Refer to Note 3 to the Consolidated Financial Statements.

Cautionary Note Required by National Instrument 51-101

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

Abbreviations

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

Terms

Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Capital Employed	*Short and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
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 and change in non-cash working capital*
Coal Bed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Corporate Reinvestment Ratio	*Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations calculated on a 12-month trailing basis*
Dated Brent	*Prices are dated less than 15 days prior to loading for delivery*
Debt to Capital Employed	*Total debt divided by total debt and shareholders' equity*
Debt to Cash Flow	*Total debt divided by cash flow from operations calculated on a 12-month trailing basis*
Delineation Well	*A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
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*
Equity	*Shares, retained earnings and accumulated other comprehensive income*
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*
Glory Hole	*An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which an interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Hectare	*One hectare is equal to 2.47 acres*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Return on Capital Employed	*Net earnings plus after tax interest expense calculated on a 12-month trailing basis divided by average capital employed*
Return on Shareholders' Equity	*Net earnings calculated on a 12-month trailing basis divided by average shareholders' equity*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Three Dimensional (3-D) Seismic	*Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

11. Forward-Looking Statements and Information

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

In particular, forward-looking statements in this document include, but are not limited to statements about the Company's general strategic plans; 2010 capital expenditure guidance; drilling and production plans for the West White Rose field; exploration plans for Canada's East Coast; development and production plans for the North Amethyst oil field; offshore Greenland exploration plans; offshore China exploration plans; delineation drilling, development and production plans for the Liwan natural gas discovery; exploration and drilling plans for the North Sumbawa II Block; development plans and receipt of an extension of the PSC for the Madura BD field; Sunrise multiphase development plans, production plans and production capacity; production optimization and drilling plans for the Tucker Oil Sands Project; development plans for the McMullen property; testing and implementation of various enhanced recovery techniques in Western Canada; conventional and shale gas exploration plans for Northeastern British Columbia; Husky's coal bed methane program; reconfiguration plans for the Lima Refinery; Continuous Catalyst Regeneration Reformer Project plans; and plans to reposition and upgrade the Toledo Refinery.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

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 which are incorporated herein by reference.

Further, 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.