MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") OCTOBER 21, 2009

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1. Summary of Quarterly Results

- Solid results in earnings and cash flow despite impact of significantly lower commodity prices and lower production due to planned East Coast satellite project tie-ins and maintenance compared with 2008.
- Financial position remains strong with debt to cash flow ratio of 1.5 and debt to capital employed ratio of 18.7%.
- Cash flow from operations includes $188 million of cash tax instalments related to 2008 earnings and $4 million related to 2009 earnings offset by refunds for prior tax years with total cash taxes paid in the quarter of $188 million.
- Overall production for the year to date within guidance; however natural gas production reflects impact of lower capital expenditures and production shut ins due to the low commodity price environment.
- Total upstream operating costs declined by 9% compared with 2008, as a result of a consistent focus on operational efficiency, reliability and financial discipline.
- Major capital projects offshore Canada's East Coast and South East Asia on schedule. Sunrise oil sands project front end engineering and design approximately 60% complete.
- Appraisal wells in the Liwan gas field now complete with successful results.

Quarterly Financial Summary [1]

	Three months ended							
(millions of dollars, except per share amounts)	**Sept. 30 2009**	June 30 2009	March 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008	March 31 2008	Dec. 31 2007
Sales and operating revenues, net of royalties	**$ 3,903**	$ 3,916	$ 3,650	$ 4,701	$ 7,715	$ 7,199	$ 5,086	$ 4,760
Net earnings	**338**	430	328	231	1,274	1,358	888	1,077
Per share - Basic and diluted	**0.40**	0.51	0.39	0.27	1.50	1.60	1.05	1.27
Cash flow from operations	**452**	833	565	330	1,999	2,079	1,538	1,423
Per share - Basic and diluted	**0.53**	0.98	0.67	0.39	2.35	2.45	1.81	1.68

[1] *2008 and 2007 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		Three months ended					
		Sept. 30 2009	June 30 2009	March 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008
WTI crude oil (1)	*(U.S. $/bbl)*	**68.30**	59.62	43.08	58.73	117.98	123.98
Brent crude oil (2)	*(U.S. $/bbl)*	**68.43**	58.79	44.40	54.91	114.78	121.38
Canadian light crude 0.3% sulphur	*($/bbl)*	**71.82**	66.21	50.09	63.92	122.53	126.73
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**59.83**	56.36	35.72	39.76	96.17	89.70
NYMEX natural gas (1)	*(U.S. $/mmbtu)*	**3.39**	3.50	4.89	6.94	10.24	10.93
NIT natural gas	*($/GJ)*	**2.87**	3.47	5.34	6.43	8.76	8.86
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**10.26**	7.72	9.20	19.41	18.34	21.95
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**8.38**	10.91	9.49	6.37	17.01	13.60
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**8.03**	9.05	10.15	6.59	11.60	13.02
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.912**	0.858	0.803	0.825	0.960	0.990

(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 2008 at U.S. $44.60/bbl subsequently recovering to U.S. $70.61/bbl on September 30, 2009, averaging U.S. $57.00/bbl in the first nine months of 2009 compared with U.S. $113.52/bbl in the first nine months of 2008, and U.S. $68.30/bbl in the third quarter of 2009 compared with U.S. $117.98/bbl in the third quarter of 2008. During the first nine months of 2009 WTI and Brent have traded in the same price range. The price of Brent ended 2008 at U.S. $36.55/bbl, subsequently recovering to U.S. $65.82/bbl on September 30, 2009, and averaged approximately U.S. $57.21/bbl in the first nine months of 2009 compared with U.S. $111.02/bbl in the first nine months of 2008, and averaged U.S. $68.43/bbl in the third quarter of 2009 compared with U.S. $114.78/bbl in the third quarter of 2008.

A portion of Husky's crude oil production is classified as heavy crude oil, which trades at a discount to light crude oil. In the third quarter of 2009, 53% of Husky's crude oil production was heavy compared with 42% in the third quarter of 2008. The light/heavy crude oil differential averaged U.S. $10.26/bbl in the third quarter of 2009 compared with U.S. $18.34/bbl in the third quarter of 2008.

The near-month natural gas price quoted on the NYMEX ended 2008 at U.S. $5.62/mmbtu. During the first nine months of 2009, the NYMEX near-month contract price of natural gas averaged U.S. $3.93/mmbtu compared with U.S. $9.73/mmbtu in the first nine months of 2008. During the third quarter of 2009, the NYMEX near-month contract price of natural gas averaged U.S. $3.39/mmbtu compared with U.S. $10.24/mmbtu in the third quarter of 2008. Low natural gas prices continue to reflect higher than average storage levels and, more significantly, the decline in industrial consumption as a result of the decline in economic activity. Natural gas storage levels were above historic levels throughout the first nine months of 2009. At the end of the third quarter of 2009, natural gas inventories were 16% higher than the five-year average and 17% 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 14% against the U.S. dollar during the following nine months, closing at U.S. $0.933 at September 30, 2009. In the first nine months of 2009, the Canadian dollar averaged U.S. $0.858 compared with U.S. $0.982 during the first nine months of 2008. During the third quarter of 2009, the Canadian dollar averaged U.S. $0.912 compared with U.S. $0.960 during the third 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. In the first nine months of 2009 the Chicago 3:2:1 crack spread averaged U.S. $9.60/bbl compared with U.S. $12.85/bbl in the first nine months of 2008. During the third quarter of 2009, the Chicago 3:2:1 crack spread averaged U.S. $8.38/bbl compared with U.S. $17.01/bbl in the third quarter of 2008. In the first nine months of 2009, the New York Harbor 3:2:1 crack spread averaged U.S. $9.08/bbl compared with U.S. $11.35/bbl in the same period of 2008. During the third quarter of 2009, the New York Harbor 3:2:1 crack spread averaged U.S. $8.03/bbl compared with U.S. $11.60/bbl in the third quarter of 2008.

During the third quarter of 2009, the 3:2:1 crack spreads were lower than the same period in 2008 reflecting the continuing weak U.S. economic environment more than offsetting the increased demand for gasoline associated with the summer driving season. Realized refining margins are affected by the product configuration of each refinery 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. With the exception of energy consumed by the industry, the cost environment has not yet reflected, to the same extent as commodity prices, the impact of the current economic conditions. However, there are encouraging signs that current economic conditions are beginning to result in reduced capital and operating costs.

Global Economic and Financial Environment

The global economic and financial crisis has reduced liquidity in financial markets, restricted access to financing and caused significant declines in economic activity resulting in 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") October 2009 Short-Term Energy Outlook[1] indicates that world oil consumption declined by 3.2 mmbbls/day in the first half of 2009 compared with the previous year, primarily in OECD countries. Preliminary data indicates that oil consumption during the third quarter of 2009 was 1.2 mmbbls/day lower than the same period in 2008. The EIA now expects oil consumption to increase in the fourth quarter of 2009 compared with the fourth quarter of 2008. Projected world oil consumption is expected to grow by 1.1 mmbbls/day in 2010, due to an expected positive growth in the global economy. The EIA estimated non-OPEC supply of crude oil averaged 50.1 mmbbls/day in the second quarter of 2009, up approximately 0.2 mmbbls/day compared with the first half of 2008. Most of the increase was from South America and the Former Soviet Union partially offset by lower production from Europe. OPEC production was 28.7 mmbbls/day in the first half of 2009, down 2.6 mmbbls/day from the year earlier. OPEC production is expected to trend upward in 2010 to average 29.2 mmbbls/day, in line with anticipated increasing 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 continues to increase above five-year averages. The EIA currently forecasts a 2.0% decline in U.S. natural gas consumption in 2009 and 0.2% in 2010. The EIA expects U.S. marketed natural gas production to increase year over year by 1.5% and decrease by 3.8% in 2010. Natural gas shortages are not anticipated as supply begins to ramp up due to improvements in technology that have reduced finding

Note:

[1] *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – October 6, 2009 Release*

and development costs, improved completion times and enhanced well productivity. The EIA expects liquefied natural gas ("LNG") imports to increase in 2009 to 471 bcf from 352 bcf in 2008 and increase to 660 bcf in 2010. LNG imports are expected to temporarily rise as LNG is redirected from Europe where storage is reaching capacity and prices have declined.

In its October outlook the EIA estimates that fuel consumption in the United States in 2009 will fall by 730 mbbls/day or 3.8%, including 330 mbbls/day or 8.4% of diesel fuel and 130 mbbls/day or 8.4% of jet fuel. Consumption of motor gasoline is expected to increase marginally (0.3%) as lower gasoline prices have partly offset the effects of the lower economic activity. The EIA's October forecast expects a 320 mbbls/day or 1.7% increase in fuel consumption in 2010. According to EIA data released on October 7, 2009, U.S. gasoline stocks were 214.4 mmbbls, 27.6 mmbbls higher than the previous year; U.S. distillate stocks were 171.8 mmbbls, 49.2 mmbbls higher than the previous year.

The current prospect that demand for energy will increase later in 2009 and 2010 depends on a number of assumptions about the timing and sustainability of a global economic recovery.

Companies with low operating costs and flexible capital expenditure plans, strong cash generation from operations, availability of cash and cash equivalents, low debt with long maturities and unused committed credit facilities will be better positioned to manage through this crisis.

In view of the economic environment, Husky took action in 2008 and prudently reduced capital spending in 2009 and is reviewing and implementing 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 is examining ways of enhancing its access to capital going forward.

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 third 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 Third 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]	$ 68.30	*U.S. $1.00/bbl*	62	0.07	44	0.05
NYMEX benchmark natural gas price [2]	$ 3.39	*U.S. $0.20/mmbtu*	29	0.03	21	0.02
WTI/Lloyd crude blend differential [3]	$ 10.26	*U.S. $1.00/bbl*	(15)	(0.02)	(11)	(0.01)
Downstream						
Canadian light oil margins	$ 0.044	*Cdn $0.005/litre*	14	0.02	10	0.01
Asphalt margins	$ 18.30	*Cdn $1.00/bbl*	12	0.01	9	0.01
New York Harbor 3:2:1 crack spread [4]	$ 8.03	*U.S. $1.00/bbl*	85	0.10	54	0.06
Consolidated						
Exchange rate (U.S. $ per Cdn $) [1] [5]	$ 0.912	*U.S. $0.01*	(48)	(0.06)	(34)	(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 September 30, 2009.

3. Results of Operations

3.1 Upstream

Upstream Net Earnings Summary

(millions of dollars)	Three months ended Sept. 30 2009	Three months ended Sept. 30 2008	Nine months ended Sept. 30 2009	Nine months ended Sept. 30 2008
Gross revenues	**$ 1,224**	$ 3,032	**$ 3,862**	$ 8,366
Royalties	**184**	691	**610**	1,772
Net revenues	**1,040**	2,341	**3,252**	6,594
Operating and administration expenses	**382**	407	**1,123**	1,200
Depletion, depreciation and amortization	**327**	369	**1,046**	1,111
Other (income) expense	**-**	24	**-**	(28)
Income taxes	**86**	462	**304**	1,276
Net earnings	**$ 245**	$ 1,079	**$ 779**	$ 3,035

Third Quarter

Upstream earnings in the third quarter of 2009 decreased by $834 million compared with the third quarter of 2008 primarily as a result of significant declines in the prices realized for crude oil and natural gas combined with a 22% decrease in production compared to the same period in 2008.

Average realized prices in the third quarter of 2009 were $62.19/bbl for crude oil, NGL and bitumen combined compared with $105.57/bbl during the same period in 2008. The narrowing of the light to heavy crude oil differential partially offset the impact of declining light crude oil prices on earnings in the third quarter of 2009 compared with the third quarter of 2008. Natural gas prices averaged $2.84/mcf in the third quarter of 2009 compared with $8.66/mcf in the same period in 2008.

Production of crude oil and natural gas declined mainly due to lower light oil production off the East Coast of Canada due to the planned extended shutdown at White Rose for tie-in work associated with satellite development and scheduled maintenance. 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.

Nine Months

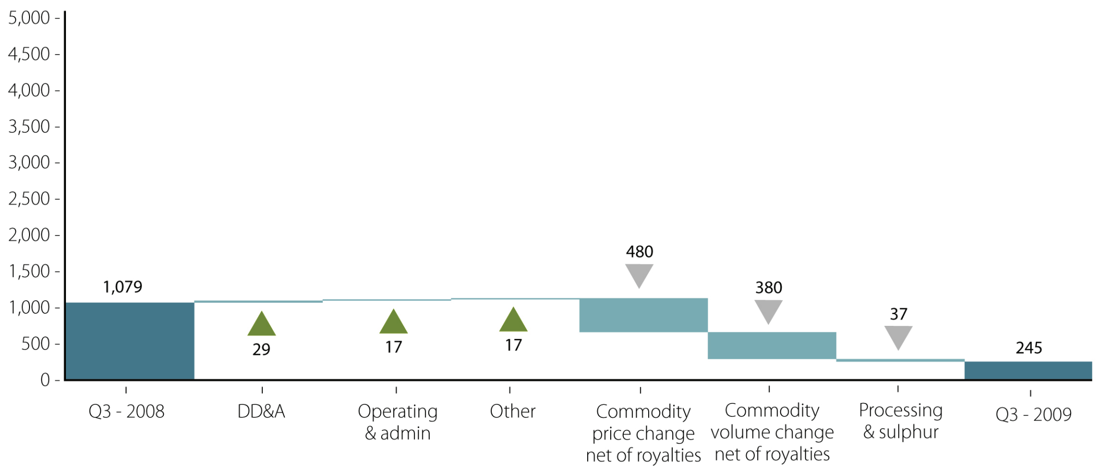
Upstream earnings in the first nine months of 2009 were $2,256 million lower than the same period in 2008 primarily as a result of the same factors impacting the third quarter.

During the first nine months of 2009 realized prices averaged $54.15/bbl for crude oil, NGL and bitumen combined compared with $97.42/bbl during the same period in 2008. The narrowing light to heavy crude oil differential in the first nine months of 2009 compared with the first nine months of 2008 partially offset the impact on earnings of declining light crude oil prices. Natural gas prices averaged $3.80/mcf in the first nine months of 2009 compared with $8.30/mcf in the same period in 2008.

Upstream Net Earnings Variance Analysis

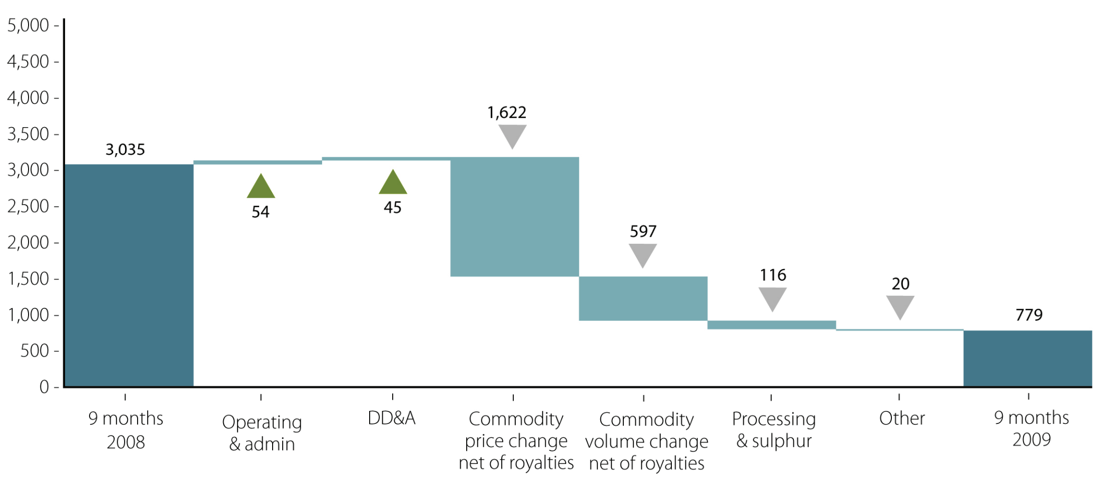
Third Quarter

Upstream After Tax Earnings Variance Analysis
($millions)



Nine Months

Upstream After Tax Earnings Variance Analysis
($millions)



Pricing

Average Sales Prices Realized		Three months ended Sept. 30		Nine months ended Sept. 30	
		2009	2008	**2009**	2008
Crude oil	*($/bbl)*				
Light crude oil & NGL		**$ 67.56**	$ 114.85	**$ 59.58**	$ 110.72
Medium crude oil		**61.28**	103.60	**53.30**	93.32
Heavy crude oil & bitumen		**59.03**	95.55	**49.36**	83.13
Total average		**62.19**	105.57	**54.15**	97.42
Natural gas	*($/mcf)*				
Average		**2.84**	8.66	**3.80**	8.30

Oil and Gas Production

Daily Gross Production		Three months ended Sept. 30		Nine months ended Sept. 30	
		2009	2008	**2009**	2008
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**23.0**	24.4	**23.0**	24.6
Medium crude oil		**24.8**	26.9	**25.5**	26.9
Heavy crude oil & bitumen		**99.7**	107.6	**101.6**	105.8
		147.5	158.9	**150.1**	157.3
East Coast Canada					
White Rose - light crude oil		**21.3**	72.7	**48.7**	71.9
Terra Nova - light crude oil		**7.7**	12.6	**10.3**	13.4
China					
Wenchang - light crude oil & NGL		**10.5**	12.0	**11.5**	12.1
Total crude oil & NGL		**187.0**	256.2	**220.6**	254.7
Natural gas	*(mmcf/day)*	**535.0**	598.3	**546.1**	602.2
Total	*(mboe/day)*	**276.2**	355.9	**311.6**	355.1

Crude Oil and NGL Production

Third Quarter

Crude oil and NGL production in the third quarter of 2009 decreased by 69.2 mbbls/day or 27% compared with the same period in 2008. Off the East Coast of Canada, production from White Rose decreased by 51.4 mbbls/day or 71% due primarily to a planned extended shutdown for tie-in work associated with the North Amethyst satellite development and scheduled maintenance. Production from the Central Drill Centre was shut in on July 21, 2009 and resumed on August 21, 2009 and the South 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 third quarter of 2009 compared with the same period in 2008.

During the third quarter of 2009, crude oil, bitumen and NGL production from Western Canada decreased by 11.4 mboe/day or 7% compared with the third 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.

Nine Months

During the first nine months of 2009, crude oil and NGL production decreased by 34.1 mbbls/day or 13%. Production at White Rose decreased approximately 5.0 mbbls/day average during the first nine months due to subsea operational issues which commenced in October 2008 and were resolved in June 2009. Production at White Rose was also impacted in the second quarter by heavy iceberg conditions, which resulted in facility throughput restrictions on the SeaRose FPSO. The decreases in the second and third quarters were partially offset by higher production in the first quarter of 2009 compared with the same period in 2008. At Terra Nova, facility operational issues resulted in lower production in 2009 compared with 2008. Terra Nova was shut down for 9 days for scheduled maintenance in the second quarter of 2009 and in the second quarter of 2008 was shut down for 14 days.

Natural Gas Production

Third Quarter

Production of natural gas decreased by 63.3 mmcf/day or 11% in the third quarter of 2009 compared with the third 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.

Nine Months

During the first nine months of 2009, natural gas production decreased by 56.1 mmcf/day or 9% compared with the same period in 2008 primarily due to the same factors impacting the third quarter.

2009 Production Guidance			Actual Production	
		Guidance 2009	Nine months ended Sept. 30 **2009**	Year ended Dec. 31 2008
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		92 - 109	**93**	123
Medium crude oil		25 - 28	**26**	27
Heavy crude oil & bitumen		95 - 105	**102**	107
		212 - 242	**221**	257
Natural gas	*(mmcf/day)*	585 - 620	**546**	594
Total barrels of oil equivalent	*(mboe/day)*	310 - 345	**312**	356

The low natural gas commodity price has impacted natural gas production in 2009 as a result of lower capital expenditures and the shut in of production. The annual production impact is estimated to be a reduction of approximately 11-12 mboe/day. Crude oil and NGL production is expected to be within guidance. Strong heavy crude oil production volumes have partially offset lower light crude oil production which has been impacted by subsea operational issues and heavy iceberg conditions earlier in the year off the East Coast of Canada. For the year, production is expected to be close to the low end of the guidance range.

Royalties

Third Quarter

In the third quarter of 2009, royalty rates averaged 15% compared with 23% in 2008. Royalty rates in Western Canada averaged 13% as a percentage of gross revenue, down from 19% in the third quarter of 2008 due to commodity price decreases of approximately 40% which resulted in reduced price sensitive royalty rates across all products and provinces. The East Coast of Canada rates averaged 25% compared with 31% in the third quarter of 2008 primarily as a result of the impact of lower production and oil prices on the overall royalty rate which is a combination of royalties based on gross revenues and net cash flow. Royalty rates in Wenchang averaged 21% compared with 35% in the third quarter of 2008. The royalty rate for Wenchang has declined due to the sliding scale royalty clause in the PSC that results in lower rates in lower commodity price environments.

Nine Months

Royalty rates averaged 16% of gross revenue in the first nine months compared with 21% in the same period in 2008. Rates in Western Canada averaged 12% compared with 17% in 2008 and off the East Coast of Canada the average rate was 26% compared with 29% in the same period in 2008. The decrease was primarily due to the same factors impacting the third quarter 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 Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2009**	2008	**2009**	2008
Western Canada	**$ 269**	$ 325	**$ 835**	$ 932
East Coast Canada	**61**	39	**144**	122
International	**5**	4	**15**	15
Total	**$ 335**	$ 368	**$ 994**	$ 1,069
Unit operating costs ($/boe)	**$ 13.14**	$ 11.20	**$ 11.69**	$ 10.96

Third Quarter

Total upstream operating costs have decreased 9% to $335 million from $368 million primarily as a result of reduced energy and other costs, partially offset by higher maintenance costs. Total upstream unit operating costs in the third quarter of 2009 averaged $13.14/boe compared with $11.20/boe in the third quarter of 2008, as lower costs were offset by lower production.

Operating costs in Western Canada averaged $12.33/boe in the third quarter of 2009 compared with $13.58/boe in the same period in 2008 primarily as a result of lower energy, treating, servicing and labour costs offset by 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 $22.75/bbl in the third quarter of 2009 compared with $4.93/bbl in the same period in 2008 primarily as a result of lower production and higher maintenance and energy costs due to high levels of activity during scheduled maintenance in the quarter.

Operating costs at the South China Sea offshore operations averaged $4.81/bbl in the third quarter of 2009 compared with $3.77/bbl in the same period in 2008 as a result of lower production.

Nine Months

Total upstream operating costs in the first nine months of 2009 decreased by 7% compared with the same period in 2008 to $994 million from $1,069 million. Operating costs in Western Canada averaged $12.71/boe in the first nine months of 2009 compared with $13.13/boe in the same period in 2008 primarily as a result of lower energy, treating and servicing costs partially offset by higher maintenance costs.

Operating costs at the East Coast offshore operations averaged $8.88/bbl in the first nine months of 2009 compared with $5.22/bbl in 2008 primarily as a result of the same factors impacting the third quarter.

Operating costs at the South China Sea offshore operations averaged $4.70/bbl in the first nine months of 2009 compared with $4.55/bbl in the same period in 2008 as a result of lower production.

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

Third Quarter

In the third quarter of 2009, total unit DD&A averaged $12.84/boe compared with $11.27/boe in the third 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.

Nine Months

During the first nine months of 2009, total unit DD&A averaged $12.29/boe compared with $11.43/boe during the same period in 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 $24 million was recorded in the third quarter of 2008 and a loss of $41 million was recorded for the first nine months of 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 the second quarter of 2008 a gain of $69 million was accounted for on the sale of 50% of Husky Oil (Madura) Limited to CNOOC Ltd.

Upstream Capital Expenditures

For the first nine months of 2009, upstream capital expenditures were $1,485 million, 71% of the 2009 capital expenditure guidance. Husky's major upstream projects offshore the East Coast of Canada and offshore China remain on schedule.

Upstream capital expenditures were $610 million (42%) in Western Canada, $479 million (32%) offshore the East Coast of Canada, $376 million (25%) in South East Asia, $15 million (1%) in the Northwest United States and $5 million offshore Greenland.

Capital Expenditures Summary [(1)]

(millions of dollars)	Three months ended Sept. 30 2009	Three months ended Sept. 30 2008	Nine months ended Sept. 30 2009	Nine months ended Sept. 30 2008
Exploration				
Western Canada	$ 33	$ 167	$ 132	$ 476
East Coast Canada and Frontier	1	49	53	94
Northwest United States	3	50	15	50
International	144	53	373	115
	181	319	573	735
Development				
Western Canada	119	407	478	1,270
East Coast Canada	110	257	426	398
International	2	-	8	3
	231	664	912	1,671
	$ 412	$ 983	$ 1,485	$ 2,406

(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 Sept. 30				Nine months ended Sept. 30			
		2009		2008		2009		2008	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	3	1	10	10	9	4	38	36
	Gas	3	1	17	11	34	22	81	64
	Dry	1	-	3	2	6	5	23	21
		7	2	30	23	49	31	142	121
Development	Oil	78	72	262	211	179	162	455	388
	Gas	11	2	157	88	103	53	292	192
	Dry	1	1	13	13	5	5	16	16
		90	75	432	312	287	220	763	596
Total		97	77	462	335	336	251	905	717

Western Canada

During the first nine months of 2009, Husky invested $610 million on exploration and development throughout the Western Canada Sedimentary Basin compared with $1,746 million during the same period in 2008. Of this, $240 million was invested on oil development and $123 million was invested on natural gas development compared with $386 million for oil development and $246 million for natural gas development in the first nine months of 2008. The Company drilled 251 net wells in the basin resulting in 166 net oil wells and 75 net natural gas wells compared with 424 net oil wells and 256 net natural gas wells in the same period 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, $40 million was spent on production optimization and operating cost reduction initiatives. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $53 million.

During the first nine months of 2009, $3 million was spent on property acquisitions. Capital expenditures on oil sands projects were $11 million during the first nine months of 2009 compared with $257 million in the same period of 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 the first nine months of 2009, $83 million was invested in drilling in these natural gas prone areas and $57 million was spent on follow-up development including tie-ins, facility installation and development drilling compared with $151 million and $90 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 21 net exploration wells were drilled primarily in the shallow regions of the Western Canada Sedimentary Basin.

The following table discloses Husky's offshore drilling activity during the first nine months of 2009:

Offshore 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
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
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 the first nine months of 2009, $426 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 continuation of facilities construction and installation. Capital expenditures on the West White Rose satellite development were related to advancing engineering design and planning.

East Coast Exploration

During the first nine months of 2009, Husky spent $53 million primarily on the Mizzen exploration well in the Flemish Pass off the coast of Newfoundland.

Northwest United States

During the first nine months of 2009, Husky spent $15 million on the Gray 31-23 exploration well in the Columbia

River Basin in south Washington State. Husky has a 50% working interest in this exploration well.

Offshore Greenland

During the first nine months of 2009, Husky spent $5 million completing an airborne gravity and magnetic survey.

Offshore China and Indonesia

During the first nine months of 2009, $348 million was spent on offshore China projects including the Liwan natural gas discovery delineation program, two exploration wells on the deepwater Block 29/26 and drilling one exploration well on Block 39/05. In Indonesia, capital expenditures during the first nine months of 2009 were $28 million, primarily related to drilling two exploration wells on the East Bawean II PSC.

2009 Upstream Capital Program [(1) (2)]

(millions of dollars)

Western Canada - oil and gas	$ 725
- oil sands	65
East Coast Canada	800
International	500
Total upstream capital expenditures	$ 2,090

(1) *Excludes capitalized administrative costs and capitalized interest.*
(2) *Upstream capital expenditures for the nine months ended September 30, 2009 were $1,485 million.*

The 2009 capital budget has been established with a view to maintaining the strength of Husky's balance sheet during a period of significant economic and financial uncertainty. Capital expenditures are focused on those projects offering the highest potential for returns and mid to long-term growth. A number of projects have been deferred pending improved market conditions.

Capital expenditures for Western Canada upstream development and exploration will continue to optimize oil and gas producing assets and develop new resource plays.

Capital spending on oil sands are primarily focused on optimizing development planning at Sunrise.

Offshore the East Coast of Canada, spending is concentrated on North Amethyst tie-back development and advancing the West White Rose tie-back project.

In China and Indonesia, capital spending is focused on delineation and evaluation of the Liwan natural gas discovery, Madura BD, Indonesia natural gas and liquids development and exploration programs offshore China and Indonesia.

3.2 Midstream

Upgrading Net Earnings Summary [1]		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2009**	2008	**2009**	2008
Gross revenues		**$ 415**	$ 859	**$ 1,127**	$ 1,990
Gross margin		**$ 51**	$ 163	**$ 217**	$ 502
Operating and administration expenses		**40**	61	**139**	198
Other (income) expense		**(1)**	-	**(3)**	(2)
Depreciation and amortization		**9**	9	**25**	22
Income taxes		**1**	28	**16**	85
Net earnings		**$ 2**	$ 65	**$ 40**	$ 199
Selected operating data:					
Upgrader throughput [2]	*(mbbls/day)*	**67.8**	79.3	**72.9**	66.8
Synthetic crude oil sales	*(mbbls/day)*	**58.6**	69.1	**60.9**	58.8
Upgrading differential	*($/bbl)*	**$ 10.16**	$ 26.09	**$ 11.66**	$ 27.94
Unit margin	*($/bbl)*	**$ 9.37**	$ 25.60	**$ 13.04**	$ 31.10
Unit operating cost [3]	*($/bbl)*	**$ 6.53**	$ 8.93	**$ 6.99**	$ 10.62

[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.

Third Quarter

During the third quarter of 2009, the upgrading differential averaged $10.16/bbl, a decrease of $15.93/bbl or 61% compared with the third quarter of 2008. The differential is equal to Husky Synthetic Blend, which sells at a premium to West Texas Intermediate, less Lloyd Heavy Blend. The overall unit margin was $9.37/bbl in 2009 compared with $25.60/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 third quarter of 2009 compared with the third quarter of 2008 which resulted from lower energy costs. Throughput in the third quarter was reduced due to unplanned shutdowns.

Nine Months

Upgrader throughput in the first nine months of 2009 was 9% higher than the same period in 2008. In addition to the factors impacting the third quarter, upgrader throughput was 23% higher in the second quarter of 2009 compared with the same period in 2008 when throughput was below capacity due to a shutdown to replace the hydrogen plant catalyst. Upgrader throughput was 16% higher in the first quarter of 2009 compared with the same period in 2008 when operational issues resulted in facility downtime and reduced production.

Infrastructure and Marketing Net Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2009**	2008	**2009**	2008
Gross revenues		**$ 1,497**	$ 4,077	**$ 5,292**	$ 11,088
Gross margin	- pipeline	**$ 23**	$ 32	**$ 80**	$ 101
	- other infrastructure and marketing	**32**	34	**144**	213
		55	66	**224**	314
Operating and administration expenses		**5**	4	**14**	11
Depreciation and amortization		**9**	8	**27**	23
Other income		**(19)**	(1)	**(28)**	(1)
Income taxes		**18**	17	**60**	85
Net earnings		**$ 42**	$ 38	**$ 151**	$ 196
Selected operating data:					
Commodity volumes managed	*(mboe/day)*	**830**	1,059	**954**	1,044
Aggregate pipeline throughput	*(mbbls/day)*	**498**	494	**520**	512

Third Quarter

Infrastructure and marketing net earnings in the third quarter of 2009 were $42 million compared with $38 million in the third quarter of 2008. Earnings in the third quarter of 2009 included unrealized gains of $19 million on natural gas storage contracts as a result of falling natural gas prices. Excluding these gains, earnings in the third quarter of 2009 were lower than the same period in 2008 due to lower margins on crude oil and natural gas trading contracts as a result of lower commodity prices and lower pipeline blending differentials and brokering margins.

Crude oil and NGL volumes managed have declined due to reduced production from the White Rose turnaround and fewer location trades at Cushing, Oklahoma for Lima refinery feedstock. Natural gas volumes have declined due to lower drilling and tie-in rates combined with well shut ins initiated in response to low gas prices. Storage purchases in the quarter have declined over 50% due to capacity utilization and decreased cycling activity.

Nine Months

Earnings in the first nine months of 2009 included unrealized gains of $28 million on natural gas storage contracts as a result of falling natural gas prices. Excluding these gains, earnings in the first nine months of 2009 were lower than the same period in 2008 primarily due to the same factors that affected the third quarter of 2009.

Midstream Capital Expenditures

For the first nine months of 2009, midstream capital expenditures totalled $74 million. At the Lloydminster upgrader, Husky spent $48 million, primarily for contingent consideration and facility reliability projects. The remaining $26 million was spent on 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]

(millions of dollars, except where indicated)		Three months ended Sept. 30 2009	Three months ended Sept. 30 2008	Nine months ended Sept. 30 2009	Nine months ended Sept. 30 2008
Gross revenues		**$ 786**	$ 1,187	**$ 1,861**	$ 2,891
Gross margin - fuel		**$ 32**	$ 21	**$ 95**	$ 94
- ethanol		**17**	9	**43**	24
- ancillary		**20**	9	**40**	33
- asphalt		**69**	37	**153**	84
		138	76	**331**	235
Operating and administration expenses		**32**	20	**78**	44
Depreciation and amortization		**23**	21	**69**	61
Income taxes		**24**	10	**53**	39
Net earnings		**$ 59**	$ 25	**$ 131**	$ 91
Selected operating data:					
Number of fuel outlets				**485**	496
Light oil sales	*(million litres/day)*	**7.8**	8.3	**7.6**	8.0
Light oil retail sales per outlet	*(thousand litres/day)*	**13.6**	13.4	**12.7**	13.1
Prince George refinery throughput	*(mbbls/day)*	**10.2**	7.9	**10.3**	9.9
Asphalt sales	*(mbbls/day)*	**32.4**	33.9	**23.9**	24.9
Lloydminster refinery throughput	*(mbbls/day)*	**27.5**	27.3	**24.7**	25.2
Ethanol production	*(thousand litres/day)*	**705.9**	598.2	**656.9**	615.7

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

Canadian Refined Products

Third Quarter

Gross margin on fuel sales was higher in the third quarter of 2009 compared with 2008 due to higher production at the Prince George Refinery which was shut down for 19 days for scheduled maintenance in the third quarter of 2008 partially offset by lower rack prices for gasoline. Light oil retail sales were lower in the third quarter of 2009 compared with the third quarter of 2008 due to fewer fuel outlets operating in 2009 compared with 2008. Asphalt gross margins increased in the third quarter of 2009 compared with 2008 due to lower crude feedstock costs as a result of lower crude oil prices compared with the same period in 2008.

The higher ethanol gross margin in the third quarter of 2009 was due to the receipt of funds earned under government incentive programs partially offset by lower prices resulting primarily from reduced gasoline rack pricing and low prices for U.S. imported ethanol. Ethanol production in the third quarter of 2009 was 18% higher than in the same period in 2008 as the third quarter of 2008 was impacted by operational issues which resulted in reduced capacity.

Light oil and asphalt sales volumes are down from the same period last year by approximately 6% and 4% respectively due to general economic conditions. Recovery is occurring in retail gasoline sales volumes offset by lower diesel commercial and cardlock sales.

Operating costs have increased in the third quarter of 2009 compared with the same period in 2008 due primarily to increased maintenance and property taxes.

Nine Months

During the first nine months of 2009, refined products earnings were higher than the same period in 2008 primarily due to the same factors that affected the third quarter of 2009.

Operating and administration expenses in the first nine months of 2008 included a $15 million credit resulting from an insurance settlement. The remaining increases are primarily due to the same factors impacting the third quarter.

U.S. Refining and Marketing Net Earnings Summary [1]		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2009**	2008	**2009**	2008
Gross revenues		**$ 1,555**	$ 2,446	**$ 4,180**	$ 6,328
Gross refining margin		**$ 163**	$ 105	**$ 772**	$ 590
Processing costs		**97**	110	**322**	270
Operating and administration expenses		**3**	5	**7**	7
Interest - net		**1**	1	**2**	2
Depreciation and amortization		**48**	42	**147**	104
Other (income) expense		**(2)**	-	**31**	-
Income taxes		**6**	(18)	**96**	75
Net earnings (loss)		**$ 10**	$ (35)	**$ 167**	$ 132
Selected operating data:					
Lima Refinery throughput	*(mbbls/day)*	**131.6**	132.8	**135.1**	136.4
Toledo Refinery throughput	*(mbbls/day)*	**66.2**	53.8	**64.1**	59.9 [2]
Refining margin	*($/bbl crude throughput)*	**$ 8.96**	$ 6.12	**$ 14.37**	$ 12.21
Refinery feedstocks and refined products inventory	*(mmbbls)*	**9.9**	7.7	**9.9**	7.7

(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 six 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 the first nine months of 2009 include both the Lima and Toledo refineries whereas the comparative period in 2008 only includes the results from the Toledo Refinery for six months.

Third Quarter

Pricing for product output at the Lima and Toledo refineries is impacted by the New York Harbor 3:2:1 and the Chicago 3:2:1 refining crack spread. Average refining crack spreads at Chicago decreased to U.S. $8.38/bbl in the third quarter of 2009 from U.S. $17.01/bbl in the third quarter of 2008, a 51% decrease. In the third quarter of 2009, average New York Harbor 3:2:1 refining crack spreads decreased to U.S. $8.03/bbl from U.S. $11.60/bbl in the same quarter in 2008, a 31% decrease.

Refining crack spreads quoted in the market are 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 and are calculated based on a last in first out ("LIFO") basis. Market crack spreads do not reflect the actual product configuration of the Lima and Toledo Refineries where 10% to 15% of refinery output consists of other refined products which sell at prices significantly different from gasoline and distillate prices and both refineries are on a FIFO basis.

In the third quarter of 2009, the Lima Refinery was impacted by various facility issues as the refinery approached the end of the fifth year of a five-year turnaround cycle. The refinery was shut down on October 2, 2009 for scheduled turnaround and maintenance work and is expected to resume production in mid November 2009.

Operating and administration expenses in the third quarter of 2008 included an additional $2 million of bad debt expense compared with the third quarter of 2009.

Other income in the third quarter of 2009 includes $3 million of gains on feedstock purchase contracts.

Nine Months

Earnings for the first nine months of 2009 include both the Lima and the BP-Husky Toledo Refineries and in the same period in 2008 include earnings from the Lima Refinery for nine months and the BP-Husky Toledo Refinery for the second and third quarters only.

Average refining crack spreads at Chicago decreased to U.S. $9.60/bbl in the first nine months of 2009 from U.S. $12.85/bbl in the same period in 2008, a 25% decrease. In the first nine months of 2009, average New York Harbor

3:2:1 refining crack spreads decreased to U.S. $9.08/bbl from U.S. $11.35/bbl in the same period in 2008, a 20% decrease.

Refining margins in the first nine months of 2009 are impacted by the same factors affecting the third quarter. Other expenses in the first nine months of 2009 include $30 million of losses on feedstock purchase contracts.

Downstream Capital Expenditures

Downstream capital expenditures totalled $166 million for the first nine months of 2009.

In Canada, capital expenditures totalled $43 million primarily for upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $123 million, of which $79 million was spent at the Lima Refinery for various debottleneck projects, optimizations and environmental initiatives that will be undertaken during the October 2009 turnaround. At the BP-Husky Toledo Refinery, capital expenditures totalled $44 million (Husky's 50% share) primarily for the continuous catalyst regeneration reformer project, facility upgrades and environmental protection.

3.4 Corporate

Corporate Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars) income (expense)	**2009**	2008	**2009**	2008
Intersegment eliminations - net	**$ 22**	$ 123	**$ (41)**	$ (14)
Administration expense	**(14)**	(44)	**(45)**	(68)
Other income (expense)	**5**	5	**(13)**	10
Stock-based compensation	**2**	44	**(1)**	(27)
Depreciation and amortization	**(14)**	(8)	**(36)**	(22)
Interest - net	**(52)**	(28)	**(139)**	(114)
Foreign exchange	**-**	76	**(1)**	60
Income taxes	**31**	(66)	**104**	42
Net earnings (loss)	**$ (20)**	$ 102	**$ (172)**	$ (133)

Intersegment eliminations are profit included in inventory that has not been sold to third parties at the end of the period. Administration expense has declined both in the third quarter of 2009 and for the first nine months of 2009 compared with the same periods in 2008 due to cost reduction initiatives. The decrease in stock-based compensation recoveries in the third quarter is due to the relatively flat share price in 2009 compared with the same period in 2008. The increase in net interest expense in the third quarter and the first nine months of 2009 is due to higher debt levels compared to the same periods in 2008. In the first nine months of 2009, other expenses includes additional insurance costs of $5 million and realized losses on forward purchases of U.S. dollars of $9 million compared to an unrealized gain on forward purchases of U.S. dollars of $20 million in the first nine months of 2008.

Foreign Exchange Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2009**	2008	**2009**	2008
Unrealized (gain) loss on translation of U.S. dollar denominated long-term debt	**$ (215)**	$ 35	**$ (266)**	$ 69
(Gain) loss on cross currency swaps	**32**	(14)	**54**	(25)
(Gain) loss on contribution receivable	**110**	(48)	**184**	(37)
Other (gains) losses	**73**	(49)	**29**	(67)
Foreign exchange (gain) loss	**$ -**	$ (76)	**$ 1**	$ (60)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.860**	U.S. $0.982	**U.S. $0.817**	U.S. $1.012
At end of period	**U.S. $0.933**	U.S. $0.944	**U.S. $0.933**	U.S. $0.944

Corporate Capital Expenditures

For the first nine months of 2009, corporate capital expenditures of $22 million were primarily for computer hardware, software, office furniture, renovations and equipment and system upgrades.

Consolidated Income Taxes

During the third quarter of 2009, consolidated income taxes were $104 million compared with $565 million in the same period of 2008 due to lower earnings. Current taxes in the third quarter of 2009 increased compared with the third quarter of 2008 due to record 2008 earnings that are taxable in 2009.

Cash taxes paid in the first nine months of 2009 were $1,143 million, of which $615 million relates to final instalments paid in respect of 2007 earnings, included in current liabilities at December 31, 2008, and $580 million relating to instalments paid in respect of 2008 earnings. Further cash tax instalments for the remainder of 2009 in respect of 2008 earnings are estimated to be $235 million with a further final payment of approximately $538 million in the first quarter of 2010.

4. Liquidity and Capital Resources

In the third quarter of 2009, Husky funded its capital programs and dividend payments by cash generated from operating activities and cash on hand. Husky maintained its strong financial position with debt of $3,312 million partially offset by cash on hand of $1,246 million for $2,066 million of net debt. Husky has no long-term debt maturing until 2012. At September 30, 2009, the Company had $1.5 billion in unused committed credit facilities, $170 million in unused short-term uncommitted credit facilities and U.S. $1.5 billion of unused capacity under the new debt shelf prospectus (refer to Section 4.4).

Cash Flow Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except ratios)	**2009**	2008	**2009**	2008
Cash flow - operating activities [(1)]	**$ 744**	$ 2,090	**$ 1,542**	$ 5,357
- financing activities	**$ (220)**	$ (751)	**$ 889**	$ (2,069)
- investing activities [(1)]	**$ (515)**	$ (909)	**$ (2,098)**	$ (2,530)
Financial Ratios				
Debt to capital employed *(percent)*			**18.7**	10.8
Debt to cash flow *(times)* [(2)]			**1.5**	0.2
Corporate reinvestment ratio *(percent)* [(2) (3)]			**143**	48

(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.*

4.1 Operating Activities

Third Quarter

In the third quarter of 2009, cash generated from operating activities amounted to $744 million compared with $2,090 million in the third quarter of 2008. Lower cash flow from operating activities was primarily due to lower commodity prices, lower crude oil and natural gas production and lower upgrading unit margins.

Nine Months

Cash generated from operating activities totalled $1,542 million in the first nine months of 2009 compared with $5,357 million in the first nine months of 2008. In addition to the factors impacting the third quarter, cash flow from operating activities was impacted by the payment of current income taxes in the first nine months of 2009 related to 2008 and 2007 earnings.

4.2 Financing Activities

Third Quarter

In the third quarter of 2009, cash used in financing activities was $220 million compared with $751 million in the third quarter of 2008. In the third quarter of 2008, $474 million was used to repay capital securities and debt. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

Nine Months

Cash provided by financing activities was $889 million in the first nine months of 2009 compared with cash used in financing activities of $2.1 billion in the first nine months of 2008. In addition to the factors impacting the third quarter, bridge financing related to the Lima acquisition was repaid in the first half of 2008. In May 2009, the Company issued U.S. $1.5 billion in long-term bonds.

4.3 Investing Activities

Third Quarter

In the third quarter of 2009, cash used in investing activities amounted to $515 million compared with $909 million in the third quarter of 2008. Cash invested in both periods was used primarily for capital expenditures.

Nine Months

Cash used in investing activities was $2.1 billion for the first nine months of 2009 compared with $2.5 billion in the first nine months of 2008. Cash invested in both periods was used primarily for capital expenditures.

4.4 Sources of Capital

Husky is currently able to fund its capital programs 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 September 30, 2009, working capital was $1,377 million compared with $404 million at December 31, 2008.

Capital Structure *(millions of dollars)*	Sept. 30, 2009 Outstanding	Available
Total short-term and long-term debt	$ 3,312	$ 1,696
Common shares, retained earnings and accumulated other comprehensive income	$ 14,399	

At September 30, 2009, Husky had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. A total of $99 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 September 30, 2009, U.S. $1.5 billion of long-term debt securities had been issued under this shelf prospectus. (Refer to Note 7 to the Consolidated Financial Statements).

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

Refer to Husky's 2008 annual and second quarter 2009 interim Management's Discussion and Analysis under the caption "Liquidity and Capital Resources," which summarize contractual obligations and commercial commitments. At September 30, 2009, Husky did not have any additional material contractual obligations and commercial commitments.

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. $3 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 September 30, 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 of $2.6 billion focuses mainly on optimizing upstream production, midstream and downstream development and progressing major projects offshore Canada's East Coast and South East Asia. The 2009 capital budget has been established with a view to maintaining the strength of Husky's balance sheet during a period of significant economic and financial uncertainty. Capital expenditures will be focused on those projects offering the highest potential for returns and mid to long-term growth.

Upstream

White Rose Development Projects

At the North Amethyst oil field, subsea installation and commissioning made significant progress. Modifications to the *SeaRose FPSO* to accommodate future production from the satellite field were carried out during the vessel's annual maintenance turnaround which took place in July and August. Subsea testing and commissioning activities are expected to be completed in the fourth quarter of 2009. Production from North Amethyst is targeted to come on stream in early 2010.

East Coast Canada Exploration

Husky continues to evaluate the results of its 2008 2,150 square kilometer 3-D seismic program with a view towards identifying future exploration prospects. During the third quarter, the Company commenced public consultations on its Environmental Assessment ("EA") process for future seismic activity offshore Labrador and a project description has been filed with the Canada-Newfoundland and Labrador Offshore Petroleum Board ("CNLOPB") to commence the EA process for potential seismic acquisition in the Sydney Basin, located between Newfoundland and Cape Breton, Nova Scotia.

On September 15, an application was submitted to the CNLOPB 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.

Offshore China Liwan Delineation

The *West Hercules* deep water drilling rig completed drilling and testing the third and final appraisal well, Liwan 3-1-4, on Block 29/26 in the South China Sea. The well tested natural gas at an equipment restricted rate of 52 mmcf/day with indications that future well deliveries could exceed 150 mmcf/day. Front end engineering design commenced in the second quarter and was approximately 40% complete at the end of the third quarter of 2009. First production is targeted in 2013. The *West Hercules* is currently drilling a new exploration well at Liwan 34-2-1, approximately 20 kilometres to the northeast of the Liwan

3-1 field and is currently undergoing repairs following damage resulting from Tropical Storm Koppu. The rig is expected to return to service in late October 2009.

Offshore China Exploration

Planning is underway for an exploration well on Block 04/35 in the East China Sea. The well is expected to be spud in late 2009 to early 2010, prior to expiry of the block on June 30, 2010. On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, existing 2-D seismic has been interpreted and planning is progressing to acquire 300 square kilometres of 3-D seismic in the March/April 2010 time frame.

During the third quarter of 2009, an application was made to relinquish deepwater Block 29/06 in the Pearl River Mouth Basin, immediately to the east of Block 29/26. Husky did not identify any prospects that warranted drilling on the 9,625 square kilometre block. Husky also elected to relinquish Block 35/18 and Block 50/14 in the Yinggehai basin effective September 2009 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 continues to await approval of an extension to the Production Sharing Contract ("PSC"). Engineering work has been tendered and commenced.

In the East Bawean II PSC, in which Husky holds a 100% interest, the *Transocean Adriatic XI* jack-up rig drilled two exploration wells in the third quarter. The wells were both plugged and abandoned without testing, although the Adiyasa-1 well did confirm the existence of non-commercial gas volume.

During the third quarter of 2009, planning and tendering for the acquisition of 1,020 kilometres of new 2-D seismic on the North Sumbawa II Block progressed. This seismic work is expected to commence in late 2009 to early 2010. Husky holds a 100% interest in the North Sumbawa II Block, comprising 5,000 square kilometres in the East Java Sea.

Sunrise Oil Sands Integrated Project

Husky and BP continue to advance the development of the Sunrise project in multiple stages (Husky 50%). 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 and take advantage of the recent economic downturn in the demand for goods and services is progressing on schedule with front end engineering design approximately 60% complete at the end of the quarter. The development of the Sunrise Oil Sands Project is strategically linked to the repositioning project at the Toledo Refinery.

Tucker Oil Sands Project

The Company 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 4.3 mboe/day at the end of the quarter. With improving crude oil prices, plans are being developed to drill a number of new infill and replacement wells to increase production during the next twelve months.

United States

The completion of the Grey 31-23 well in the Columbia River Basin has yielded fresh water and only minor gas from the Oligocene aged sands, and these zones will be abandoned. The results of the well will be incorporated into a broader evaluation of the basin.

Western Canada

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") enhanced oil recovery program, which currently includes ASP developments at Gull Lake and Fosterton, Saskatchewan and operating ASP applications at Warner and Crowsnest, Alberta, continues to advance. Incremental oil recovery continues to hold steady at Warner following ASP injection. The Crowsnest flood is showing strong preliminary signs of improved oil response. At Gull Lake, the ASP facility is fully operational and injection of alkaline and polymer commenced in September 2009 and surfactants will be injected in the fourth quarter of 2009. All preliminary reservoir technical work is complete at the Fosterton ASP project and Husky is proceeding with detailed facility cost design. The Fosterton ASP flood development is expected to extend into 2011. Husky is the operator and holds a 62.4% working interest in this project.

Northeastern British Columbia Exploration

In the Bullmoose - Sukunka region of Northeastern British Columbia the Burnt River c-A61-A (55% WI) and the Sukunka a-27-F (20% WI) wells have been tied in and are capable of producing at rates in excess of 30 mmcf/day from the Belcourt Formation. Both the a-27-F well and the c-A61-A well have commenced production. Husky is finalizing negotiations with a partner to participate in another Belcourt formation test that is expected to spud later in October 2009.

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 September Husky commenced drilling a 13 well program at the cold production project. These wells are expected to be completed and on stream by year end. Based on the results of a 2008 delineation and seismic program, the Company submitted an application to the Energy Resources Conservation Board in December 2008 to construct the thermal pilot. Pilot implementation will be delayed until economic conditions improve.

Coal Bed Methane

During the third quarter of 2009, Husky tied in 16 gross (7 net) coal bed methane producing wells from the Belly River formation. A total of 47 gross (23 net) coal bed methane wells have been tied in during the first nine months of 2009. No coal bed methane wells were drilled during the third quarter.

Non-Thermal EOR

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. This pilot will continue to provide insight into reservoir response and process economics. Production continued at a second pilot project utilizing CO_2 in the third quarter of 2009.

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 continuing. An airborne gravity and magnetics acquisition was completed in the second quarter of 2009 and is currently being evaluated. 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. Husky has completed acquisition of the first of two 1,000 square kilometre 3-D programs over Block 7 and is currently working on the acquisition of a second 1,000 square kilometre 3-D program over Block 5.

Downstream

Lima, Ohio Refinery

An engineering evaluation to reconfigure the Lima Refinery completed in 2008 is currently under review. The reconfiguration is intended to increase processing capacity of heavier, less costly, crude oil feedstock to enhance margins and increase flexibility in product outputs. Implementation of this project has been deferred due to current market conditions.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project progressed in the first nine months of 2009. The project has been intentionally delayed to capture deflationary market pressure, achieving a reduction in capital costs. The air permit was issued by the Ohio Environmental Protection Agency in August 2009 and the project is pending internal sanction prior to commencement of construction. The scope of this project is to replace two naphtha reformers and one hydrogen plant with one 42,000 bbls/day continuous catalyst regeneration reformer system plant. The project's objectives are to effectively and safely improve profitability while reducing operating risk, meet future product requirements and reduce the environmental footprint.

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 be coincident 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.

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'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.

The global financial and economic crisis, which developed in 2008 has increased the risk associated with timely access to debt capital and banking markets and the current market instability may have an impact on Husky's ability to borrow in the capital debt markets at acceptable rates.

In June 2009, the United States House of Representatives passed the Waxman-Markey clean energy bill, 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. 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 the first nine months of 2009, interest rate risk management activities resulted in a decrease to interest expense of $1 million.

At September 30, 2009, Husky has interest rate swaps on 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. During the first nine months of 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 the first nine months of 2009, a loss of less than $1 million was recognized in other expenses on the Consolidated Statement of Earnings and Comprehensive Income.

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

Cross currency swaps resulted in an addition to interest expense of $2 million in the first nine months of 2009.

Foreign Currency Risk Management

At September 30, 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 September 30, 2009, the cost of a U.S. dollar in Canadian currency was $1.0722.

During the first nine months of 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.

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 September 30, 2009, 100% or $3.3 billion of Husky's outstanding debt was denominated in U.S. dollars. The percentage of the Company's debt exposed to the Cdn/U.S. exchange rate decreases to 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. As a result, the Company's net investment hedge is limited to the remaining U.S. $687 million. For the nine months ended September 30, 2009, the unrealized foreign exchange gain arising from the translation of the debt was $89 million, net of tax expense of $16 million, 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 September 30, 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 September 30, 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; however, the Company has voluntary elected to apply these amendments to its September 30, 2009 interim financial statements as permitted by the transitional provisions of the amendments. The adoption of the amendments to this standard did not have an impact on the Company's financial statements.

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.

In May 2009, the CICA amended 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 included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for Husky on December 31, 2009.

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 and in March 2009, the AcSB issued a second omnibus exposure draft which confirms the IFRS transition date as January 1, 2011 for all Canadian publicly accountable enterprises.

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.

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.

The IFRS conversion will also result in other impacts, some of which may be significant in nature. Initial 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 third quarter of 2009, the Company moved into 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.

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.

At this time, the impact on the Company's financial position and results of operations is not reasonably determinable or estimable for any of the IFRS conversion impacts identified.

10. Outstanding Share Data

(in thousands)	October 15 2009	December 31 2008
Issued and outstanding		
Number of common shares	849,861	849,355
Number of stock options	28,708	30,827
Number of stock options exercisable	14,301	7,239

11. Reader Advisories

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended September 30, 2009 are compared with results for the three months ended September 30, 2008 and results for the nine months ended September 30, 2009 are compared with results for the nine months ended September 30, 2008. Discussions with respect to Husky's financial position as at September 30, 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

Management's Discussion and Analysis 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 generally accepted accounting principles, 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:

(millions of dollars)		Three months ended Sept. 30 2009	Three months ended Sept. 30 2008 [1]	Nine months ended Sept. 30 2009	Nine months ended Sept. 30 2008 [1]
Non-GAAP	Cash flow from operations	**$ 452**	$ 1,999	**$ 1,850**	$ 5,616
	Settlement of asset retirement obligations	**(9)**	(13)	**(24)**	(37)
	Change in non-cash working capital	**301**	104	**(284)**	(222)
GAAP	Cash flow - operating activities	**$ 744**	$ 2,090	**$ 1,542**	$ 5,357

[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:

(millions of dollars)		Three months ended Sept. 30 2009	Three months ended Sept. 30 2008 [1]	Nine months ended Sept. 30 2009	Nine months ended Sept. 30 2008 [1]
GAAP	Net earnings	**$ 338**	$ 1,274	**$ 1,096**	$ 3,520
	Net foreign exchange	**(12)**	(57)	**(8)**	(41)
	Net financial instruments	**(19)**	9	**8**	16
	Net stock-based compensation	**(1)**	(30)	**1**	19
	Net inventory write-downs	**19**	72	**44**	79
	Sale of 50% of Husky Oil (Madura) Limited to CNOOC Ltd.	**-**	-	**-**	(69)
Non-GAAP	Adjusted net earnings	**$ 325**	$ 1,268	**$ 1,141**	$ 3,524

[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.

Husky's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Husky by Canadian securities regulatory authorities, which permits Husky to provide disclosure required by and consistent with the requirements of the United States Securities and Exchange Commission and the Financial Accounting Standards Board in the United States in place of much of the disclosure expected by National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Please refer to "Disclosure of Exemption Under National Instrument 51-101" on page 3 of Husky's Annual Information Form for the year ended December 31, 2008 filed with securities regulatory authorities for further information.

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	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. It is more viscous than 10 degrees API*
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*

12. 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," "encouraging," "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; 2009 production and capital expenditure guidance; pursuit of cost containment and efficiency opportunities; plans to enhance liquidity in the near term; evaluation of prospective East Coast drilling locations; development and production plans for the North Amethyst oil field; production optimization plans for the Tucker in-situ oil sands project; Sunrise multiphase development plans, production plans and production capacity; development and drilling plans for the McMullen property; exploration plans for the Columbia River Basin; the offshore China exploration program; delineation drilling and production plans for the Liwan natural gas discovery; the receipt of an extension of the PSC for the Madura BD natural gas and NGL field; exploration plans for the North Sumbawa II exploration blocks; testing and implementation of various enhanced recovery techniques in Western Canada; exploration plans for Northeastern British Columbia; offshore Greenland exploration plans; plans to reposition and upgrade the Toledo Refinery; Continuous Catalyst Regeneration Reformer Project plans; Lima Refinery turnaround plans; and plans to reconfigure the Lima Refinery.

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

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.