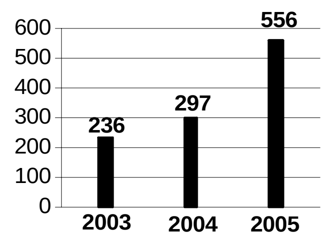
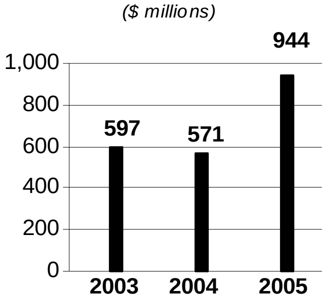
HUSKY ENERGY ANNOUNCES 2005 THIRD QUARTER RESULTS

Third Quarter
Net Earnings
($ millions)



Calgary, Alberta - Husky Energy Inc. reported net earnings of $556 million or $1.31 per share (diluted) in the third quarter of 2005, an 87 percent increase over net earnings of $297 million or $0.70 per share (diluted) in the third quarter of 2004. Included in net earnings for the third quarter of 2005 is a net charge of $54 million related to stock-based compensation and a net gain of $54 million related to U.S. dollar denominated debt translation. Cash flow from operations was $944 million or $2.23 per share (diluted) in the third quarter of 2005, a 65 percent increase compared with $571 million or $1.34 per share (diluted) in the third quarter of 2004. Sales and operating revenues net of royalties were $2.8 billion in the third quarter of 2005, a 26 percent increase compared with $2.2 billion in the third quarter of 2004.

Third Quarter
Cash Flow from Operations
($ millions)

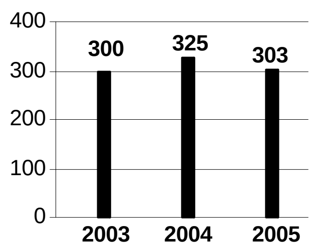


"Our strong operating results in the third quarter of 2005, bolstered by continuing high commodity prices, should lead to a record year for the Company," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc.

Production in the third quarter of 2005 was 303,200 barrels of oil equivalent per day, compared with 324,800 barrels of oil equivalent per day in the third quarter of 2004. Total crude oil and natural gas liquids production was 190,000 barrels per day, compared with 208,100 barrels per day in the third quarter of 2004. Natural gas production was 679.2 million cubic feet per day, compared with 700.4 million cubic feet per day in the third quarter of 2004.

"Production in crude oil and natural gas was slightly below our expectations due to continued wet weather in Western Canada and lengthy operational issues and a maintenance turnaround at Terra Nova," said Mr. Lau. "Overall, we expect our 2005 annual production to be below the range of our guidance by approximately four percent."

Third Quarter
Total Production
(mboe/day)



During the third quarter of 2005, Husky made good progress on its White Rose project. The *SeaRose FPSO* is currently undergoing offshore hook-up and commissioning at the White Rose oil field. First oil is anticipated before year-end and will add approximately 67,500 barrels per day of light oil production net to Husky when it attains full productive capacity.

At the White Rose oil field, Husky began drilling two delineation wells to further define reserves in the South and West Avalon Pools. In September, Husky commenced a 750-square-kilometre 3-D seismic program to assist in defining other potential prospects on several blocks in the Jeanne d'Arc Basin. During the quarter, an exploratory well was drilled at the Lewis Hill prospect in the South Whale Basin. The well was plugged and abandoned without testing.

In the Northwest Territories, Husky completed a 2-D seismic program on Block EL 397 containing the Summit Creek B-44 discovery and announced plans to drill two wells in the Summit Creek area in January 2006. One of the wells will assess the size of the pool discovered by Summit Creek B-44. The other exploration well will test a separate undrilled prospect.

In Central Alberta, Husky is continuing its expansion program to develop coal bed methane or natural gas from coal in the Horseshoe Canyon Formation. Husky and its joint venture partner plan to drill approximately 400 wells in the Fenn Rumsey area near Drumheller in 2006.

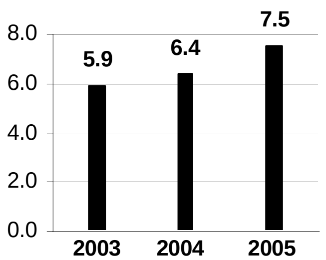
At Husky's Tucker oil sands project near Cold Lake, Alberta facility construction continues on schedule and is now 43 percent complete. Drilling of the 30 horizontal well pairs is on target. For Husky's Sunrise 200,000 barrels per day oil sands project near Fort McMurray, Alberta, Husky expects to receive regulatory approval by the end of 2005 or early 2006.

In the South China Sea, Husky drilled Wushi 17-1-1, an exploration well on Block 23/15 in the Beibu Gulf. Hydrocarbons were encountered in the Weizhou Formation at a depth of 2,397 metres. The well was sidetracked to determine the extent of the hydrocarbon zone and the results of the well are still being evaluated. Husky has identified several prospects in the Beibu Gulf and is currently drilling an exploration well on the adjacent Block 23/20.

At Husky's heavy oil Upgrader in Lloydminster, Saskatchewan, a major turnaround was completed. The Upgrader achieved a record of 4.3 million working hours without a lost time accident, which is approximately 9.5 years of operation. The turnaround resulted in the completion of major maintenance as well as the first half of the debottlenecking work that will increase capacity in 2006 to 82,000 barrels per day from 77,000 barrels per day.

Following the successful completion of the first phase of the Clean Fuels Project, Husky is now producing low sulphur gasoline at its Prince George Refinery. The second phase of the project will enable the Refinery to produce low sulphur diesel and increase overall capacity to 12,000 barrels per day from 10,000 barrels per day by mid 2006.

First Nine Months Sales and Operating Revenues
($ billions)



Husky's net earnings for the first nine months of 2005 were $1,334 million or $3.15 per share (diluted), a 71 percent increase over net earnings of $781 million or $1.84 per share (diluted) for the same period in 2004. Cash flow from operations in the first nine months of 2005 was $2,588 million or $6.11 per share (diluted), a 50 percent increase from $1,728 million or $4.07 per share (diluted) for the same period in 2004. Sales and operating revenues net of royalties in the first nine months of 2005 were $7.5 billion, compared with $6.4 billion in the same period of 2004.

Production in the first nine months of 2005 was 310,500 barrels of oil equivalent per day, compared with 325,200 barrels of oil equivalent per day for the same period in 2004. Total crude oil and natural gas liquids production was 196,900 barrels per day, compared with 210,800 barrels per day in the first nine months of 2004. Natural gas production was 681.6 million cubic feet per day, compared with 686.5 million cubic feet per day for the same period in 2004.

All expectations, forecasts, assumptions and beliefs about our future production, financial results, financial condition and development of our business are forward-looking statements, as described in more detail under the caption "Forward-looking Statements." Our actual financial results and condition may differ materially due to a number of risks and uncertainties. A number of those risks and uncertainties are described under the caption "Business Environment." In particular the reader is cautioned about statements we have made concerning future production and strategic plans contained under the caption "Business Development."

SUMMARY OF QUARTERLY RESULTS

Financial Summary (1)

	Three months ended							
	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31	Dec. 31
(millions of dollars, except per share amounts and ratios)	**2005**	2005	2005	2004	2004	2004	2004	2003
Sales and operating revenues, net of royalties	**$ 2,763**	$ 2,493	$ 2,201	$ 2,018	$ 2,191	$ 2,210	$ 2,021	$ 1,800
Segmented earnings								
Upstream	**$ 445**	$ 307	$ 239	$ 112	$ 161	$ 204	$ 236	$ 169
Midstream	**61**	130	169	77	50	53	60	46
Refined Products	**27**	20	18	(3)	18	21	5	6
Corporate and eliminations	**23**	(63)	(42)	39	68	(49)	(46)	31
Net earnings	**$ 556**	$ 394	$ 384	$ 225	$ 297	$ 229	$ 255	$ 252
Per share - Basic	**$ 1.31**	$ 0.93	$ 0.91	$ 0.53	$ 0.70	$ 0.54	$ 0.60	$ 0.60
- Diluted	**1.31**	0.93	0.91	0.53	0.70	0.54	0.60	0.59
Cash flow from operations	**944**	828	816	469	571	581	576	561
Per share - Basic	**2.23**	1.95	1.93	1.11	1.34	1.37	1.36	1.33
- Diluted	**2.23**	1.95	1.93	1.11	1.34	1.37	1.36	1.32
Dividends per common share	**0.14**	0.14	0.12	0.12	0.12	0.12	0.10	0.10
Special dividend per common share	**-**	-	-	0.54	-	-	-	-
Total assets	**14,712**	14,058	13,690	13,240	12,901	12,542	12,317	11,949
Total long-term debt including current portion	**1,896**	2,192	2,290	2,103	2,096	2,229	1,993	1,989
Return on equity (2) *(percent)*	**22.9**	20.2	18.3	17.0	17.7	16.8	21.8	26.4
Return on average capital employed (2) *(percent)*	**17.9**	15.3	13.9	13.0	13.4	12.7	16.2	18.9

(1) 2004 and 2003 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.
(2) Calculated for the twelve months ended for the periods shown.

Daily Production, before Royalties		Three months ended			
		Sept. 30 2005	June 30 2005	March 31 2005	Dec. 31 2004	Sept. 30 2004
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**31.8**	31.7	31.9	32.9	33.1
Medium crude oil		**30.3**	30.6	32.4	33.7	34.5
Heavy crude oil		**103.3**	100.9	110.4	113.8	108.8
		165.4	163.2	174.7	180.4	176.4
East Coast Canada						
Terra Nova - light crude oil		**10.2**	13.5	13.7	10.1	11.5
China						
Wenchang - light crude oil		**14.4**	17.3	18.5	17.9	20.2
		190.0	194.0	206.9	208.4	208.1
Natural gas	*(mmcf/day)*	**679.2**	689.3	676.2	697.4	700.4
Total	*(mboe/day)*	**303.2**	308.9	319.6	324.6	324.8

Total crude oil and natural gas production declined by two percent to average 303.2 mboe/day in the third quarter of 2005 from 308.9 mboe/day in the second quarter of 2005. Third quarter production declines resulted from lower production from Terra Nova, which was shut down during the month of September to perform a scheduled turnaround that has been extended to deal with gas compression reliability issues. The decline in production at Wenchang in the third quarter of 2005 compared with the second quarter of 2005 was primarily due to typhoon related downtime. Production from our properties in Western Canada was marginally up during the third quarter of 2005 compared with the second quarter of 2005. Heavy crude oil production increased by two percent, the effect of which was partially offset by a one percent decline in natural gas production. Western Canada third quarter production was maintained compared with the second quarter of 2005 in spite of wet weather issues and a tight market for materials and services, all of which have caused delays in drilling, completion and tie-in programs.

BUSINESS DEVELOPMENT

In each business segment we are executing our strategic plan both in respect of existing operations and for our transition into new areas of sustainable growth.

UPSTREAM

Gross Production		Nine months ended Sept. 30 **2005**	Forecast [1] 2005	Nine months ended Sept. 30 2004	Year ended December 31 2004
Crude oil & NGL	*(mbbls/day)*				
Light crude oil & NGL		**61.0**	64 - 71	68.1	66.2
Medium crude oil		**31.1**	32 - 36	35.4	35.0
Heavy crude oil		**104.8**	112 - 120	107.3	108.9
		196.9	208 - 227	210.8	210.1
Natural gas	*(mmcf/day)*	**681.6**	700 - 740	686.5	689.2
Total barrels of oil equivalent	*(mboe/day)*	**310.5**	325 - 350	325.2	325.0

[1] We expect our 2005 annual production to be below the range of our guidance by approximately four percent.

Our conventional oil and gas properties throughout the Western Canada Sedimentary Basin ("WCSB") form the foundation of our upstream business and provide the majority of our cash flow. Although the WCSB is considered to be mature, with production declines typically over 20 percent per annum, this resource base will continue to provide cash flow necessary to fund our emerging growth opportunities offshore Canada's East Coast, in international properties in China and Indonesia and in non-conventional production from oil sands in Western Canada. In addition, we expect to continue to realize additional value by managing our operating costs in the WCSB through consolidation via strategic acquisitions and divestitures and improvements in production technology and practice.

At September 30, 2005, we have invested in the following major development projects offshore Canada's East Coast and in the Alberta oil sands:

Project		Productive Capacity (1)	Working Interest	Schedule
White Rose	Offshore East Coast	68 mbbls/day	72.5%	Late 2005
Tucker	Oil sands	30 mbbls/day	100%	2006 - 2007
Sunrise	Oil sands	200 mbbls/day (2)	100%	2009 - 2012

(1) Husky interest.
(2) Sunrise will be developed in phases; ultimate planned rate is 200 mbbls/day.

In addition to these major projects currently under development, exploration and development programs in the WCSB are expected to increase production of natural gas from both shallow gas step-out drilling and drilling in the deep basin of Alberta and in the foothills region of Alberta and northeastern British Columbia for high potential natural gas targets. Our exploration program will also target prospects offshore Newfoundland and Labrador, in the Central Mackenzie Valley area of the Northwest Territories, offshore China and in the Madura Strait in Indonesia.

White Rose

The *SeaRose FPSO* arrived at the White Rose oil field on August 22 and was connected to the subsea production system on August 25. Drilling and completion of the 10 wells required at first oil are progressing with two wells still to be completed. The project is expected to be on schedule to achieve first oil before year-end.

Tucker

At Tucker, a steam-assisted gravity drainage Alberta oil sands project, drilling operations are on schedule at approximately 60 percent completion. The central plant construction is on schedule at approximately 43 percent completion.

Sunrise

At Sunrise, discussions continue to address project related questions of the key stakeholders. Project development activity is progressing with evaluation of marketing and downstream solution options for the project.

Exploration

- Western Canada

In Western Canada during the third quarter of 2005, we drilled a total of 142 gross exploratory wells (78 net) that resulted in 28 gross oil completions (28 net) and 107 gross natural gas completions (43 net).

During the third quarter of 2005, our primary exploration activities were conducted in the foothills, deep basin and northern plains areas of Alberta and British Columbia where we drilled 13 gross exploration wells (7 net) resulting in 13 gross natural gas wells (7 net). Activity in these areas is restricted to less environmentally sensitive areas until the ground is frozen during the winter months.

- Northwest Territories

During the third quarter we conducted a seismic program in the Central Mackenzie Valley in preparation for further testing of the area around the Summit Creek B-44 oil and gas discovery. Several additional structures have been identified and we are currently planning a two well drilling program for this winter.

- East Coast

During the third quarter of 2005, we drilled an exploratory well, the Lewis Hill G-85 in the South Whale Basin, which lies approximately 350 kilometres south of St. John's, Newfoundland and Labrador. The well was plugged and abandoned without testing.

The Lewis Hill rig was subsequently moved to the White Rose oil field where it successfully drilled one pilot hole and a side-track to delineate a northern extension of the White Rose South Avalon reservoir, which is currently under development. The rig is being moved to drill a delineation well into the West Avalon reservoir.

We are currently conducting a 3-D seismic program in the northern Jeanne d'Arc Basin offshore the East Coast of Canada. This survey will provide further information about several identified prospects north of the White Rose oil field.

- China

During the third quarter of 2005, the Wushi 17-1-1 exploration well was drilled on Block 23/15 in the Beibu Gulf. The well was subsequently side-tracked to a new bottom hole location to evaluate the extent of the oil accumulation encountered by the original well bore. The original well bore penetrated an oil column approximately 75 metres thick. The side-tracked well bore encountered a thinner oil column with low flow rates after testing. The size and extent of the discovery is being evaluated based on the well results and seismic data.

The Wushi 32-1-1 well is currently being drilled on the adjacent Block 23/20 in the Beibu Gulf.

- Indonesia

During the third quarter of 2005, development engineering re-validation work commenced for the production facilities at the Madura natural gas development project and negotiations continued toward establishing natural gas sales agreements.

MIDSTREAM

Husky Lloydminster Upgrader

The debottleneck projects are scheduled to increase the plant's throughput capacity from 77 mbbls/day to 82 mbbls/day of synthetic crude oil and diluent. Completion is expected in the third quarter of 2006 with connections made in September 2005 during the scheduled plant turnaround. The projects are expected to cost approximately $60 million.

REFINED PRODUCTS

Prince George Refinery

During the third quarter of 2005, the first phase of the Prince George Refinery Clean Fuels Project was completed. On August 15, gasoline was produced that meets the new Government of Canada specifications for sulphur content. The second phase of the project will modify the refinery to produce low sulphur diesel fuel and increase the plant capacity from 10 mbbls/day to 12 mbbls/day. The second phase is expected to be on stream by the second quarter of 2006.

Lloydminster Ethanol Plant

At September 30, 2005, the ethanol plant currently being constructed at Lloydminster, Saskatchewan, adjacent to the Husky Lloydminster Upgrader, was 55 percent complete and overall construction was 30 percent complete. The plant is scheduled to be completed in the second quarter of 2006.

Minnedosa Ethanol Plant

At Minnedosa, Manitoba the plant expansion project progressed in the early stages of approvals and design engineering. The project would expand the existing ethanol plant from 10 million litres per year to 130 million litres per year. The project is contingent on receiving government approvals, which are expected in October 2005 and having acceptable economics.

BUSINESS ENVIRONMENT

Husky's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

- Volatility in crude oil and natural gas prices
- Cost to find, develop, produce and deliver crude oil and natural gas
- Demand for heavier grades of crude oil
- Demand for and ability to deliver natural gas
- The exchange rate between the Canadian and U.S. dollar
- Refined petroleum products margins
- Demand for Husky's pipeline capacity
- Demand for refined petroleum products
- Government regulation
- Cost of capital

Average Benchmark Prices and U.S. Exchange Rate

		Three months ended				
		Sept. 30 2005	June 30 2005	March 31 2005	Dec. 31 2004	Sept. 30 2004
WTI crude oil [(1)]	*(U.S. $/bbl)*	**$ 63.10**	$ 53.17	$ 49.84	$ 48.28	$ 43.88
Canadian par light crude 0.3% sulphur	*($/bbl)*	**77.04**	66.43	62.02	58.01	56.61
Lloyd @ Lloydminster heavy crude oil	*($/bbl)*	**44.13**	27.95	22.62	25.31	35.47
NYMEX natural gas [(1)]	*(U.S. $/mmbtu)*	**8.49**	6.73	6.27	7.11	5.76
NIT natural gas	*($/GJ)*	**7.75**	6.99	6.34	6.72	6.32
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**18.90**	21.27	19.57	19.82	12.86
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.833**	0.804	0.815	0.819	0.765

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

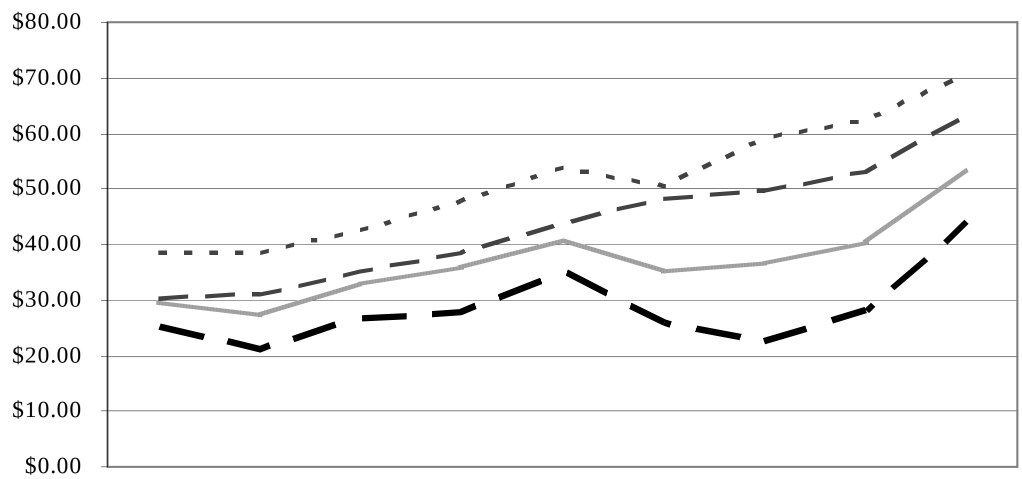
COMMODITY PRICE RISK

Our earnings depend largely on the profitability of our upstream business segment which is most significantly affected by fluctuations in oil and gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond our control.

Crude Oil

WTI and Husky Average Crude Oil Prices

($/bbl)

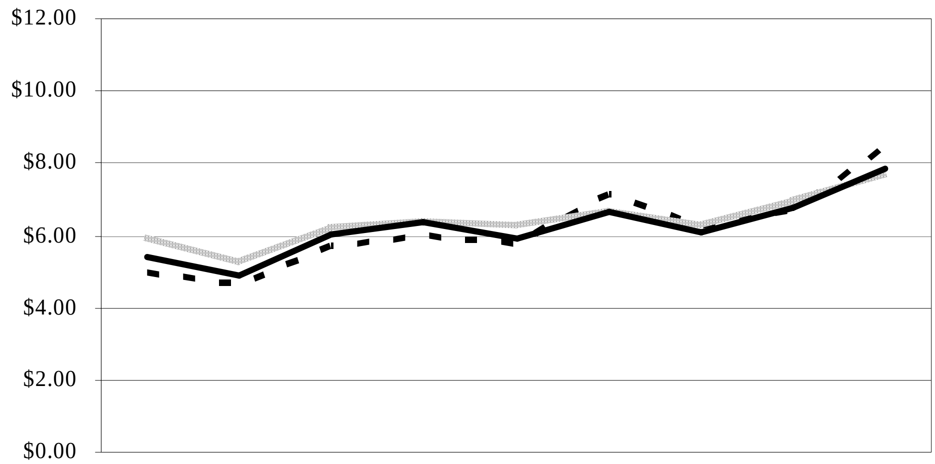


	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04	Q1-05	Q2-05	Q3-05
West Texas Intermediate ("WTI") (U.S. $)	$30.20	$31.18	$35.15	$38.32	$43.88	$48.28	$49.84	$53.17	$63.10
Husky average light crude oil price (C $)	$38.49	$38.55	$42.50	$47.99	$53.94	$50.29	$58.94	$62.49	$70.59
Husky average medium crude oil price (C $)	$29.68	$27.25	$32.97	$35.98	$40.59	$35.06	$36.50	$40.45	$53.41
Husky average heavy crude oil price (C $)	$25.13	$20.84	$26.38	$27.54	$34.92	$25.81	$22.53	$27.95	$44.17

The prices received for our crude oil and NGL are related to the price of crude oil in world markets. Prices for heavy crude oil and other lesser quality crudes trade at a discount or differential to light crude oil due to the additional processing costs.

Natural Gas

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices



	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04	Q1-05	Q2-05	Q3-05
NYMEX natural gas (U.S. $/mmbtu)	$4.97	$4.58	$5.69	$5.97	$5.76	$7.11	$6.27	$6.73	$8.49
NIT natural gas (C $/GJ)	$5.97	$5.30	$6.26	$6.45	$6.32	$6.72	$6.34	$6.99	$7.75
Husky average natural gas price (C $/mcf)	$5.40	$4.87	$6.05	$6.38	$5.92	$6.64	$6.07	$6.76	$7.86

The price of natural gas in North America is affected by regional supply and demand factors, particularly those affecting the United States such as weather conditions, pipeline delivery capacity, production disruptions, the availability of alternative sources of less costly energy supply, inventory levels and general industry activity levels. Periodic imbalances between supply and demand for natural gas are common and result in volatile pricing.

Upgrading Differential

The profitability of our heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil and related products exceed the costs of the heavy oil feedstock plus the related operating costs, a significant portion of which is energy related. An increase in the price of blended heavy crude oil feedstock that is not accompanied by an equivalent increase in the sales price of synthetic crude oil would reduce the profitability of our upgrading operations. We have significant crude oil production that trades at a discount to light crude oil, and any negative effect of a narrower heavy/light crude oil differential on upgrading operations would be more than offset by a positive effect on revenues in the upstream segment from heavy crude oil production.

Refined Products Margins

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which affect refinery feedstock costs, and third-party light oil refined product purchases. Our ability to maintain refined products margins in an environment of higher feedstock costs is contingent upon our ability to pass on our higher costs to our customers.

Integration

Our production of light, medium and heavy crude oil and natural gas and the efficient operation of our upgrader, refineries and other infrastructure provide opportunities to take advantage of any fluctuation in commodity prices while assisting in managing commodity price volatility. Although we are predominantly an oil and gas producer, the nature of our integrated organization is such that the upstream business segment's output provides input to the midstream and refined products segments.

FOREIGN EXCHANGE RISK

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our 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 our 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 and 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, 2005, 84 percent or $1.6 billion of our long-term debt was denominated in U.S. dollars. The Cdn/U.S. exchange rate at the end of the third quarter of 2005 was $1.1611. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 56 percent when the cross currency swaps are included. Refer to the section "Financial and Derivative Instruments."

INTEREST RATES

We maintain a portion of our debt in floating rate facilities which are exposed to interest rate fluctuations. We will occasionally fix our floating rate debt or create a variable rate for our fixed rate debt using derivative financial instruments. Refer to the section "Financial and Derivative Instruments."

ENVIRONMENTAL REGULATIONS

Most aspects of Husky's business are subject to environmental laws and regulations. Similar to other companies in the oil and gas industry, we incur costs for preventive and corrective actions in addition to costs incurred for asset retirement obligations. Changes to regulations could have an adverse effect on our results of operations and financial condition.

INTERNATIONAL OPERATIONS

In addition to commodity price risk, Husky's international upstream operations may be affected by a variety of factors including political and economic developments, exchange controls, currency fluctuations, royalty and tax increases, import and export regulations and other foreign laws or policies affecting foreign trade or investment.

SENSITIVITY ANALYSIS

The following table indicates the relative effect of changes in certain key variables on our pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the third quarter of 2005. Each separate 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

Item	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
		($ millions)	*($/share)* [4]	*($ millions)*	*($/share)* [4]
WTI benchmark crude oil price	*U.S. $1.00/bbl*	71	0.17	46	0.11
NYMEX benchmark natural gas price [1]	*U.S. $0.20/mmbtu*	35	0.08	22	0.05
Light/heavy crude oil differential [2]	*Cdn $1.00/bbl*	(32)	(0.07)	(20)	(0.05)
Light oil margins	*Cdn $0.005/litre*	17	0.04	11	0.03
Asphalt margins	*Cdn $1.00/bbl*	11	0.03	7	0.02
Exchange rate (U.S. $ / Cdn $) [3]	*U.S. $0.01*	(59)	(0.14)	(39)	(0.09)

(1) *Includes decrease in earnings related to natural gas consumption.*
(2) *Includes impact of upstream and upgrading operations only.*
(3) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $11 million in net earnings based on September 30, 2005 U.S. dollar denominated debt levels.*
(4) *Based on September 30, 2005 common shares outstanding of 424.1 million*

RESULTS OF OPERATIONS

UPSTREAM

Upstream Earnings Summary

(millions of dollars)	Three months ended Sept. 30 **2005**	Three months ended Sept. 30 2004	Nine months ended Sept. 30 **2005**	Nine months ended Sept. 30 2004
Gross revenues	**$ 1,422**	$ 1,183	**$ 3,616**	$ 3,293
Royalties	**246**	197	**576**	537
Hedging	**-**	169	**-**	358
Net revenues	**1,176**	817	**3,040**	2,398
Operating and administration expenses	**262**	255	**751**	720
Depletion, depreciation and amortization	**280**	278	**831**	794
Income taxes	**189**	123	**467**	283
Earnings	**$ 445**	$ 161	**$ 991**	$ 601

Net Revenue Variance Analysis

(millions of dollars)	Crude oil & NGL	Natural gas	Other	Total
Three months ended September 30, 2004	$ 509	$ 291	$ 17	$ 817
Price changes	205	116	-	321
Volume changes	(75)	(11)	-	(86)
Royalties	(34)	(15)	-	(49)
Hedging	166	3	-	169
Processing and sulphur	-	-	4	4
Three months ended September 30, 2005	**$ 771**	**$ 384**	**$ 21**	**$ 1,176**
Nine months ended September 30, 2004	$ 1,457	$ 887	$ 54	$ 2,398
Price changes	357	139	-	496
Volume changes	(165)	(12)	-	(177)
Royalties	(42)	3	-	(39)
Hedging	359	(1)	-	358
Processing and sulphur	-	-	4	4
Nine months ended September 30, 2005	**$ 1,966**	**$ 1,016**	**$ 58**	**$ 3,040**

Third Quarter

Upstream earnings were $284 million higher in the third quarter of 2005 than in the third quarter of 2004 as a result of the following factors:

- Higher crude oil, natural gas and sulphur prices
- Hedging diverted $169 million in the third quarter of 2004; third quarter of 2005 commodity prices were not hedged
- Higher sales volume of sulphur and NGL

Partially offset by:

- Lower sales volume of crude oil and natural gas
- Higher unit operating costs
- Higher unit depletion, depreciation and amortization
- Higher income taxes

Nine Months

The factors that affected upstream performance in the first nine months of 2005 compared with the first nine months of 2004 were essentially the same as those during the third quarter of 2005 and 2004.

Unit Operating Costs

Unit operating costs were eight percent higher in the third quarter of 2005 compared with the same period in 2004 due to higher energy costs, increased natural gas compression costs, higher natural gas well count and production declines. In addition, high commodity prices are affecting rates charged by our service providers with the high level of industry activity creating tight service markets.

Unit Depletion, Depreciation and Amortization

Unit depletion, depreciation and amortization expense increased nine percent in the third quarter of 2005 compared with the same period in 2004. The increase was primarily due to a higher capital base in 2005 as a result of increased requirement for production maintenance capital for our properties in the Western Canada Sedimentary Basin, higher capital expenditures for offshore operations and higher capital costs associated with the purchase of reserves in place. In addition, the higher commodity prices, as with operating costs, increased the cost of materials and services in our capital costs.

Average Sales Prices		Three months ended Sept. 30		Nine months ended Sept. 30	
		2005	2004	**2005**	2004
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 67.21**	$ 53.54	**$ 60.85**	$ 47.44
Medium crude oil		**53.41**	40.59	**43.34**	36.47
Heavy crude oil		**44.17**	34.92	**31.46**	29.68
Total average		**62.42**	41.60	**42.43**	36.53
Natural Gas	*($/mcf)*				
Average		**7.86**	5.92	**6.90**	6.12

Effective Royalty Rates [1]	Three months ended Sept. 30		Nine months ended Sept. 30	
Percentage of upstream sales revenues	**2005**	2004	**2005**	2004
Crude oil & NGL	**16%**	14%	**14%**	13%
Natural gas	**21%**	23%	**20%**	23%
Total	**17%**	17%	**16%**	16%

[1] *Before commodity hedging.*

Upstream Revenue Mix [1]	Three months ended Sept. 30		Nine months ended Sept. 30	
Percentage of upstream sales revenues, after royalties	**2005**	2004	**2005**	2004
Light crude oil & NGL	**26%**	27%	**29%**	27%
Medium crude oil	**10%**	11%	**10%**	11%
Heavy crude oil	**30%**	31%	**26%**	28%
Natural gas	**34%**	31%	**35%**	34%
	100%	100%	**100%**	100%

[1] *Before commodity hedging*

OPERATING NETBACKS

Western Canada

Light Crude Oil Netbacks (1)	Three months ended Sept. 30		Nine months ended Sept. 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 65.25**	$ 47.60	**$ 57.85**	$ 44.51
Royalties	**10.02**	7.25	**7.54**	7.72
Operating costs	**6.62**	7.57	**9.16**	8.56
Netback	**$ 48.61**	$ 32.78	**$ 41.15**	$ 28.23

Medium Crude Oil Netbacks (1)	Three months ended Sept. 30		Nine months ended Sept. 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 53.13**	$ 40.38	**$ 43.32**	$ 36.45
Royalties	**9.69**	7.21	**7.68**	6.37
Operating costs	**11.44**	10.85	**10.68**	10.05
Netback	**$ 32.00**	$ 22.32	**$ 24.96**	$ 20.03

Heavy Crude Oil Netbacks (1)	Three months ended Sept. 30		Nine months ended Sept. 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 44.19**	$ 34.91	**$ 31.57**	$ 29.75
Royalties	**6.25**	4.25	**3.83**	3.40
Operating costs	**9.88**	9.90	**9.53**	9.51
Netback	**$ 28.06**	$ 20.76	**$ 18.21**	$ 16.84

Natural Gas Netbacks (2)	Three months ended Sept. 30		Nine months ended Sept. 30	
Per mcfge	**2005**	2004	**2005**	2004
Sales revenues	**$ 7.90**	$ 6.00	**$ 6.97**	$ 6.12
Royalties	**1.78**	1.49	**1.56**	1.45
Operating costs	**1.17**	0.93	**1.04**	0.87
Netback	**$ 4.95**	$ 3.58	**$ 4.37**	$ 3.80

Total Western Canada Upstream Netbacks (1)	Three months ended Sept. 30		Nine months ended Sept. 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 48.86**	$ 37.42	**$ 39.86**	$ 35.00
Royalties	**8.82**	6.77	**6.88**	6.31
Operating costs	**8.56**	8.08	**8.31**	7.83
Netback	**$ 31.48**	$ 22.57	**$ 24.67**	$ 20.86

(1) Includes associated co-products converted to boe.
(2) Includes associated co-products converted to mcfge.

Terra Nova Crude Oil Netbacks	Three months ended Sept. 30		Nine months ended Sept. 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 69.62**	$ 51.49	**$ 62.23**	$ 46.96
Royalties	**12.64**	3.13	**5.61**	1.64
Operating costs	**5.61**	3.91	**4.16**	3.11
Netback	**$ 51.37**	$ 44.45	**$ 52.46**	$ 42.21

Wenchang Crude Oil Netbacks	Three months ended Sept. 30		Nine months ended Sept. 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 67.98**	$ 55.86	**$ 64.04**	$ 48.48
Royalties	**6.53**	5.84	**6.00**	4.95
Operating costs	**2.56**	2.00	**2.43**	2.06
Netback	**$ 58.89**	$ 48.02	**$ 55.61**	$ 41.47

Total Upstream Segment Netbacks (1)	Three months ended Sept. 30		Nine months ended Sept. 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 50.49**	$ 39.08	**$ 42.07**	$ 36.39
Royalties	**8.83**	6.59	**6.78**	6.01
Operating costs	**8.18**	7.57	**7.84**	7.26
Netback	**$ 33.48**	$ 24.92	**$ 27.45**	$ 23.12

(1) Includes associated co-products converted to boe.

MIDSTREAM

Upgrading Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2005**	2004	**2005**	2004
Gross margin		**$ 92**	$ 93	**$ 494**	$ 261
Operating costs		**48**	55	**151**	160
Other recoveries		**(1)**	(2)	**(4)**	(4)
Depreciation and amortization		**6**	5	**15**	14
Income taxes		**12**	11	**101**	25
Earnings		**$ 27**	$ 24	**$ 231**	$ 66
Selected operating data:					
Upgrader throughput (1)	*(mbbls/day)*	**48.3**	71.6	**63.8**	66.2
Synthetic crude oil sales	*(mbbls/day)*	**43.9**	60.1	**55.9**	54.1
Upgrading differential	*($/bbl)*	**$ 23.53**	$ 15.26	**$ 29.73**	$ 15.31
Unit margin	*($/bbl)*	**$ 23.01**	$ 16.88	**$ 32.41**	$ 17.60
Unit operating cost (2)	*($/bbl)*	**$ 11.04**	$ 8.30	**$ 8.71**	$ 8.82

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

Upgrading Earnings Variance Analysis

(millions of dollars)

Three months ended September 30, 2004	$	24
Volume		(25)
Margin		25
Operating costs - energy related		5
Operating costs - non-energy related		1
Other		(1)
Depreciation and amortization		(1)
Income taxes		(1)
Three months ended September 30, 2005	**$**	**27**
Nine months ended September 30, 2004	$	66
Volume		7
Margin		226
Operating costs - non-energy related		9
Depreciation and amortization		(1)
Income taxes		(76)
Nine months ended September 30, 2005	**$**	**231**

Third Quarter

Upgrading earnings increased in the third quarter of 2005 by $3 million compared with the third quarter of 2004 due to:

- Wider upgrading differential
- Lower energy and non-energy related unit operating costs

Partially offset by:

- Lower sales volume of synthetic crude oil as a result of a scheduled turnaround

Nine Months

With the exception of sales volume, slightly higher energy related operating costs and income taxes, the factors that affected upgrading performance in the first nine months of 2005 compared with the first nine months of 2004 were essentially the same as those during the third quarter of 2005 and 2004. Income taxes in the first nine months of 2005 compared with the same period in 2004 were higher due to higher income.

Infrastructure and Marketing Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)	**2005**	2004	**2005**	2004
Gross margin - pipeline	**$ 21**	$ 23	**$ 68**	$ 65
- other infrastructure and marketing	**38**	26	**154**	103
	59	49	**222**	168
Other expenses	**3**	3	**8**	7
Depreciation and amortization	**5**	6	**16**	16
Income taxes	**17**	14	**69**	48
Earnings	**$ 34**	$ 26	**$ 129**	$ 97
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**418**	461	**472**	496

Third Quarter

Infrastructure and marketing earnings increased by $8 million in the third quarter of 2005 compared with the third quarter of 2004 due to:

- Higher income from oil and gas commodity marketing

Partially offset by:

- Lower pipeline throughput and margins
- Higher income taxes due to higher income

Nine Months

The factors that affected infrastructure and marketing earnings in the first nine months of 2005 compared with the first nine months of 2004 were essentially the same as those during the third quarter of 2005 and 2004.

REFINED PRODUCTS

Refined Products Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2005**	2004	**2005**	2004
Gross margin - fuel sales		**$ 41**	$ 26	**$ 94**	$ 86
- ancillary sales		**10**	8	**26**	22
- asphalt sales		**24**	20	**71**	41
		75	54	**191**	149
Operating and other expenses		**19**	18	**55**	53
Depreciation and amortization		**14**	9	**34**	27
Income taxes		**15**	9	**37**	25
Earnings		**$ 27**	$ 18	**$ 65**	$ 44
Selected operating data:					
Number of fuel outlets				**519**	533
Light oil sales	*(million litres/day)*	**9.3**	8.8	**8.8**	8.5
Light oil sales per outlet	*(thousand litres/day)*	**13.3**	11.9	**12.7**	11.5
Prince George refinery throughput	*(mbbls/day)*	**9.6**	9.2	**9.7**	10.2
Asphalt sales	*(mbbls/day)*	**29.9**	27.6	**22.5**	23.4
Lloydminster refinery throughput	*(mbbls/day)*	**25.9**	23.8	**24.9**	25.1

Third Quarter

Refined products earnings increased by $9 million in the third quarter of 2005 compared with the third quarter of 2004 due to:

- Higher marketing margins and sales volume for gasoline and distillates
- Higher marketing margins and sales volume of asphalt products
- Higher income from restaurant, convenience store and facilities rent

Partially offset by:

- Higher depreciation expense
- Higher income taxes

Nine Months

The factors that affected refined products earnings in the first nine months of 2005 compared with the first nine months of 2004 were essentially the same as those during the third quarter of 2005 and 2004.

CORPORATE

Corporate Summary [(1)]	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2005**	2004	**2005**	2004
Intersegment eliminations - net	**$ 44**	$ (5)	**$ 53**	$ 25
Administration expenses	**4**	6	**15**	16
Stock-based compensation	**79**	22	**177**	45
Accretion	**1**	1	**2**	2
Other - net	**(57)**	1	**(51)**	5
Depreciation and amortization	**6**	8	**17**	26
Interest on debt	**36**	32	**107**	101
Interest capitalized	**(36)**	(19)	**(91)**	(54)
Foreign exchange	**(63)**	(84)	**(36)**	(60)
Income taxes	**(37)**	(30)	**(111)**	(79)
Earnings (loss)	**$ 23**	$ 68	**$ (82)**	$ (27)

(1) *2004 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.*

Foreign Exchange Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2005**	2004	**2005**	2004
Gain on translation of U.S. dollar denominated long-term debt				
Realized	**$ (5)**	$ (3)	**$ (9)**	$ (5)
Unrealized	**(84)**	(106)	**(49)**	(58)
	(89)	(109)	**(58)**	(63)
Cross currency swaps	**22**	22	**16**	8
Other (gains) losses	**4**	3	**6**	(5)
	$ (63)	$ (84)	**$ (36)**	$ (60)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.816**	U.S. $0.746	**U.S. $0.831**	U.S. $0.774
At end of period	**U.S. $0.861**	U.S. $0.791	**U.S. $0.861**	U.S. $0.791

Third Quarter

Corporate earnings decreased by $45 million in the third quarter of 2005 compared with the third quarter of 2004 due to:

- Higher stock-based compensation expense during the third quarter of 2005
- Higher interest costs
- Higher intersegment profit elimination
- Lower gains on translation of U.S. denominated debt

Partially offset by:

- Gain on settlement of litigation
- Lower depreciation and amortization
- Higher capitalized interest resulting from the higher White Rose and Tucker project capital base
- Higher income tax recovery

Nine Months

The factors that affected corporate expense in the first nine months of 2005 compared with the first nine months of 2004 were essentially the same as those during the third quarter of 2005 and 2004.

LIQUIDITY AND CAPITAL RESOURCES

OPERATING ACTIVITIES

In the third quarter of 2005, cash generated from operating activities amounted to $1.1 billion compared with $577 million in the third quarter of 2004. Higher cash flow from operating activities was primarily due to higher commodity prices and higher change in non-cash working capital.

FINANCING ACTIVITIES

In the third quarter of 2005, cash used in financing activities amounted to $290 million compared with $25 million in the third quarter of 2004. During the third quarter of 2005, higher short and long-term debt repayments and dividends net of long-term debt issue resulted in higher use of cash compared with the third quarter of 2004.

INVESTING ACTIVITIES

In the third quarter of 2005, cash used in investing activities amounted to $776 million compared with $625 million in the third quarter of 2004. Cash was used primarily for capital expenditures partially offset by proceeds from asset sales.

Capital Expenditures

Capital Expenditures Summary (1)	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2005**	2004	**2005**	2004
Upstream				
Exploration				
Western Canada	**$ 189**	$ 41	**$ 503**	$ 245
East Coast Canada and Frontier	**28**	3	**46**	17
International	**16**	5	**39**	16
	233	49	**588**	278
Development				
Western Canada	**262**	310	**856**	855
East Coast Canada	**202**	149	**448**	355
International	**4**	1	**7**	5
	468	460	**1,311**	1,215
	701	509	**1,899**	1,493
Midstream				
Upgrader	**38**	12	**85**	38
Infrastructure and Marketing	**11**	5	**24**	12
	49	17	**109**	50
Refined Products	**57**	29	**105**	53
Corporate	**6**	8	**14**	19
Capital expenditures	**813**	563	**2,127**	1,615
Settlement of asset retirement obligations	**(8)**	(7)	**(18)**	(18)
Capital expenditures per Consolidated Statements of Cash Flows	**$ 805**	$ 556	**$ 2,109**	$ 1,597

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

Upstream capital expenditures totaled $1,899 million, 89 percent of total consolidated capital expenditures during the first nine months of 2005 compared with $1,493 million or 92 percent of the total, during the first nine months of 2004.

Upstream Capital Expenditures	Nine months ended Sept. 30
(millions of dollars)	**2005**
Western Canada Sedimentary Basin sustaining exploitation	**$ 940**
Western Canada foothills and deep basin exploration	**160**
Western Canada oil sands	**259**
Eastern Canada offshore and Northwest Territories	**494**
International exploration and development	**46**
	$ 1,899

The remaining capital expenditures during the first nine months of 2005 amounting to $228 million were related primarily to the Lloydminster upgrader debottlenecking project, the Prince George refinery clean fuels project and the Lloydminster ethanol plant project.

Western Canada Wells Drilled (1) (2)		Three months ended Sept. 30				Nine months ended Sept. 30			
		2005		2004		**2005**		2004	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**28**	**28**	6	4	**63**	**60**	19	16
	Gas	**107**	**43**	29	23	**239**	**136**	153	134
	Dry	**7**	**7**	1	1	**26**	**26**	30	30
		142	**78**	36	28	**328**	**222**	202	180
Development	Oil	**154**	**147**	200	188	**285**	**266**	396	368
	Gas	**164**	**136**	221	204	**442**	**401**	632	592
	Dry	**10**	**8**	14	14	**25**	**23**	51	48
		328	**291**	435	406	**752**	**690**	1,079	1,008
Total		**470**	**369**	471	434	**1,080**	**912**	1,281	1,188

(1) *Excludes stratigraphic test wells.*

(2) *Includes non-operated wells.*

SOURCES OF CAPITAL

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and proved developed reserves, to acquire strategic oil and gas assets, repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices part of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining our production, it may be necessary to utilize alternative sources of capital to continue our strategic investment plan during periods of low commodity prices. As a result we continually examine our options with respect to sources of long and short-term capital resources. In addition, from time to time we engage in hedging a portion of our production to protect cash flow.

Sources and Uses of Cash	Nine months ended Sept. 30	Year ended December 31
(millions of dollars)	**2005**	2004
Cash sourced		
Cash flow from operations [(1)]	**$ 2,588**	$ 2,197
Debt issue	**3,027**	2,200
Asset sales	**70**	36
Proceeds from exercise of stock options	**5**	18
Proceeds from monetization of financial instruments	**30**	8
	5,720	4,459
Cash used		
Capital expenditures	**2,109**	2,349
Corporate acquisitions	**-**	102
Debt repayment	**3,224**	1,959
Special dividend on common shares	**-**	229
Ordinary dividends on common shares	**170**	195
Settlement of asset retirement obligations	**24**	40
Other	**23**	24
	5,550	4,898
Net cash (deficiency)	**170**	(439)
Increase (decrease) in non-cash working capital	**(135)**	443
Increase in cash and cash equivalents	**35**	4
Cash and cash equivalents - beginning of period	**7**	3
Cash and cash equivalents - end of period	**$ 42**	$ 7
Increase (decrease) in non-cash working capital		
Cash positive working capital change		
Accounts receivable decrease	**$ -**	$ 209
Accounts payable and accrued liabilities increase	**157**	323
	157	532
Cash negative working capital change		
Accounts receivable increase	**113**	-
Inventory increase	**176**	77
Prepaid expense increase	**3**	12
	292	89
Increase (decrease) in non-cash working capital	**$ (135)**	$ 443

(1) *Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.*

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2005, our working capital deficiency was $539 million compared with $824 million at December 31, 2004. These working capital deficits are primarily the result of accounts payable related to capital expenditures for exploration and development. Settlement of these current liabilities is funded by cash provided by operating activities and to the extent necessary by bank borrowings. This position is a common characteristic of the oil and gas industry which, by the nature of its business, spends large amounts of capital.

Capital Structure

(millions of dollars)	September 30, 2005 Outstanding (U.S. $)	Outstanding (Cdn $)	Available (Cdn $)
Short-term bank debt	$ -	$ -	$ 177
Long-term bank debt			
Syndicated credit facility	-	-	1,000
Bilateral credit facilities	-	-	150
Medium-term notes	-	300	
Capital securities	225	261	
U.S. public notes	1,050	1,219	
U.S. senior secured bonds	85	99	
U.S. private placement notes	15	17	
Total short-term and long-term debt	$ 1,375	$ 1,896	$ 1,327
Common shares and retained earnings		$ 7,380	

Financial Ratios

(millions of dollars, except ratios)	Three months ended Sept. 30 **2005**	Three months ended Sept. 30 2004	Nine months ended Sept. 30 **2005**	Nine months ended Sept. 30 2004
Cash flow - operating activities	**$ 1,105**	$ 577	**$ 2,605**	$ 1,742
- financing activities	**$ (290)**	$ (25)	**$ (543)**	$ 26
- investing activities	**$ (776)**	$ (625)	**$ (2,027)**	$ (1,769)
Debt to capital employed *(percent)*			**20.4**	25.5
Corporate reinvestment ratio (1) (2)			**0.9**	1.2

(1) *Calculated for the twelve months ended for the periods shown.*
(2) *Reinvestment ratio is based on net capital expenditures including corporate acquisitions.*

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Contractual Obligations

Payments due by period (millions of dollars)	Total	October - December 2005	2006-2007	2008-2009	Thereafter
Long-term debt	$ 1,896	$ 17	$ 326	$ 494	$ 1,059
Operating leases	537	15	176	161	185
Firm transportation agreements	901	53	375	262	211
Unconditional purchase obligations	1,502	150	1,186	151	15
Lease rentals	330	11	88	88	143
Exploration work agreements	42	18	15	-	9
Engineering and construction commitments	705	311	382	12	-
	$ 5,913	$ 575	$ 2,548	$ 1,168	$ 1,622

OFF BALANCE SHEET ARRANGEMENTS

We do not utilize off balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

We engage in the ordinary course of business in the securitization of accounts receivable. Our receivable securitization program is fully utilized at $350 million. The securitization agreement terminates on January 31, 2009. The accounts receivable are sold to an unrelated third party on a revolving basis. In accordance with the agreement we must provide a loss reserve to replace defaulted receivables.

The securitization program provides us with cost effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated our liquidity would not be materially reduced.

TRANSACTIONS WITH RELATED PARTIES

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, we paid approximately $10 million for office space in Western Canadian Place during 2004.

SIGNIFICANT CUSTOMERS

We did not have any customers that constituted more than 10 percent of total sales and operating revenues during the first nine months of 2005.

FINANCIAL AND DERIVATIVE INSTRUMENTS

POWER CONSUMPTION

At September 30, 2005, we had hedged power consumption as follows:

(millions of dollars, except where indicated)	Notional Volumes *(MW)*	Term	Price	Unrecognized Gain (Loss)
Fixed price purchase	10.0	Oct. to Dec. 2005	$ 49.25/MWh	$ 1
	12.5	Oct. to Dec. 2005	$ 50.50/MWh	1
				$ 2

FOREIGN CURRENCY RISK MANAGEMENT

At September 30, 2005, we had the following cross currency debt swaps in place:

- U.S. $150 million at 7.125 percent swapped at $1.45 to $218 million at 8.74 percent until November 15, 2006
- U.S. $150 million at 6.250 percent swapped at $1.41 to $212 million at 7.41 percent until June 15, 2012
- U.S. $75 million at 6.250 percent swapped at $1.19 to $90 million at 5.65 percent until June 15, 2012
- U.S. $50 million at 6.250 percent swapped at $1.17 to $59 million at 5.67 percent until June 15, 2012

At September 30, 2005 the cost of a U.S. dollar in Canadian currency was $1.1611.

In the first nine months of 2005, the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $16 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains of $12 million in the first nine months of 2005.

Husky entered into long-dated forwards that fixed the exchange rate on U.S. dollar sales. These contracts were unwound in 2004 and during the first nine months of 2005, we recognized a gain of $8 million.

INTEREST RATE RISK MANAGEMENT

In the first nine months of 2005, the interest rate risk management activities resulted in a decrease to interest expense of $11 million.

The cross currency swaps resulted in an addition to interest expense of $7 million in the first nine months of 2005.

Husky has interest rate swaps on $200 million of long-term debt effective February 8, 2002 whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During the first nine months of 2005, these swaps resulted in an offset to interest expense amounting to $4 million.

Husky has interest rate swaps on U.S. $200 million of long-term debt effective February 12, 2002 whereby 7.55 percent was swapped for an average U.S. LIBOR + 194 bps until November 15, 2011. During the first nine months of 2005, these swaps resulted in an offset to interest expense amounting to $5 million.

In May 2005, Husky unwound the interest rate swaps on U.S. $300 million of long-term debt due June 15, 2019. Proceeds of $30 million have been deferred and are being amortized to income over the remaining term of the underlying debt. During the first nine months of 2005, the impact of these swaps before they were unwound was an offset to interest expense amounting to $3 million.

The amortization of previous interest rate swap terminations resulted in an additional $6 million offset to interest expense in the first nine months of 2005.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Certain of our accounting policies require that we make 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 our Management's Discussion and Analysis for the year ended December 31, 2004 available at www.sedar.com.

NEW ACCOUNTING STANDARDS

Effective January 1, 2005, we retroactively reclassified the capital securities from equity to long-term debt in accordance with the Canadian Institute of Chartered Accountants handbook section 3860, "Financial Instruments – Disclosure and Presentation." As a result the return on capital securities is included in interest expense rather than as a charge to retained earnings.

OUTSTANDING SHARE DATA

(in thousands, except per share amounts)		Nine months ended Sept. 30 **2005**	Year ended December 31 2004
Share price [1]	High	**$ 69.95**	$ 35.65
	Low	**$ 32.30**	$ 22.73
	Close at end of period	**$ 64.57**	$ 34.25
Average daily trading volume		**677**	482
Weighted average number of common shares outstanding			
	Basic	**423,912**	423,362
	Diluted	**423,912**	424,303
Issued and outstanding at end of period [2]			
Number of common shares		**424,112**	423,736
Number of stock options		**7,341**	9,964
Number of stock options exercisable		**1,557**	1,417
Number of warrants		**-**	25

(1) Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.

(2) There were no significant issuances of common shares, stock options or any other securities convertible into, or exercisable or exchangeable for common shares during the period from September 30, 2005 to October 14, 2005.

ADDITIONAL INFORMATION

Management's Discussion and Analysis is our explanation of our financial performance for the period covered by the unaudited financial statements along with an analysis of our financial position and prospects. It should be read in conjunction with the unaudited Consolidated Financial Statements for the nine months ended September 30, 2005 in this Quarterly Report and the audited Consolidated Financial Statements, Management's Discussion and Analysis and Annual Information Form for the year ended December 31, 2004 filed March 18, 2005 on SEDAR at www.sedar.com. The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada. All comparisons refer to the third quarter of 2005 compared with the third quarter of 2004 and the first nine months of 2005 compared with the first nine months of 2004, unless otherwise indicated. All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. Unless otherwise indicated, all production volumes quoted are gross, which represent our working interest share before royalties. Prices quoted include or exclude the effect of hedging as indicated. Crude oil has been classified as the following: light crude oil has an API gravity of 30 degrees or more; medium crude oil has an API gravity of 21 degrees or more and less than 30 degrees; heavy crude oil has an API gravity of less than 21 degrees.

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 from operating activities" as determined in accordance with generally accepted accounting principles as an indicator of our financial performance. Our determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations generated by each business segment represents a measurement of financial performance for which each reporting business segment is responsible. The items reported under the caption, "Corporate and eliminations", are required to reconcile to the consolidated total and are not considered to be attributable to a business segment.

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

(millions of dollars)		Nine months ended Sept. 30 2005	Year ended December 31 2004
Non-GAAP	Cash flow from operations	**$ 2,588**	$ 2,197
	Settlement of asset retirement obligations	**(24)**	(40)
	Change in non-cash working capital	**41**	169
GAAP	Cash flow - operating activities	**$ 2,605**	$ 2,326

ADVISORY REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Our disclosure of reserves data and other oil and gas information has been made in reliance on an exemption to us by the Canadian Securities Administrators. The exemption permits us to make our disclosures in accordance with U.S. disclosure requirements and practices in order to provide comparability with U.S. and other international issuers. These requirements may differ from Canadian requirements under National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Our proved reserves disclosure has been evaluated in accordance with the standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934.

We use 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 well head.

FORWARD-LOOKING STATEMENTS

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This Management's Discussion and Analysis contains certain forward-looking statements relating, but not limited, to Husky's operations, anticipated financial performance, levels of production, business prospects and strategies and which are based on our expectations, estimates, projections and assumptions and were made by us in light of experience and perception of historical trends. All statements that address expectations or projections about the future, including statements about strategy for growth, expected expenditures, commodity prices, costs, production volumes and operating or financial results, are forward-looking statements. Some of our forward-looking statements may be identified by words like "expects", "anticipates", "plans", "intends", "believes", "projects", "could", "vision", "goal", "objective" and similar expressions. In addition, our production forecast and our estimate of productive capacity for White Rose, Tucker and Sunrise and plans associated with our exploration programs are forward-looking statements. Our business is subject to risks and uncertainties, some of which are similar to other energy companies and some of which are unique to Husky. Our actual results may differ materially from those expressed or implied by our forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

The reader is cautioned not to place undue reliance on our forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, that contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to:

- Fluctuations in commodity prices
- The accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates
- The uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- Changes in general economic, market and business conditions
- Fluctuations in supply and demand for our products
- Fluctuations in the cost of borrowing
- Our use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates
- Political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which we operate
- Our ability to receive timely regulatory approvals
- The integrity and reliability of our capital assets
- The cumulative impact of other resource development projects
- The maintenance of satisfactory relationships with unions, employee associations and joint venturers
- Competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy
- Actions by governmental authorities, including changes in environmental and other regulations that may impose restriction in areas where we operate
- The ability and willingness of parties with whom we have material relationships to fulfill their obligations
- The occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties, whose operations or assets directly or indirectly affect us

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars)		September 30 2005		December 31 2004
		(unaudited)		*(audited)*
Assets				
Current assets				
Cash and cash equivalents	**$**	**42**	$	7
Accounts receivable		**559**		446
Inventories		**450**		274
Prepaid expenses		**61**		52
		1,112		779
Property, plant and equipment - (full cost accounting)		**21,414**		19,451
Less accumulated depletion, depreciation and amortization		**8,114**		7,258
		13,300		12,193
Goodwill		**160**		160
Other assets		**140**		108
	$	**14,712**	$	13,240
Liabilities and Shareholders' Equity				
Current liabilities				
Bank operating loans	**$**	**-**	$	49
Accounts payable and accrued liabilities		**1,605**		1,498
Long-term debt due within one year *(note 5)*		**46**		56
		1,651		1,603
Long-term debt *(notes 3, 5)*		**1,850**		2,047
Other long-term liabilities *(note 4)*		**730**		632
Future income taxes		**3,101**		2,758
Commitments and contingencies *(note 6)*				
Shareholders' equity				
Common shares *(note 7)*		**3,522**		3,506
Retained earnings		**3,858**		2,694
		7,380		6,200
	$	**14,712**	$	13,240
Common shares outstanding *(millions) (note 7)*		**424.1**		423.7

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 amounts as restated.

Consolidated Statements of Earnings

(millions of dollars, except per share amounts) (unaudited)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2005	2004	**2005**	2004
Sales and operating revenues, net of royalties	**$ 2,763**	$ 2,191	**$ 7,457**	$ 6,422
Costs and expenses				
Cost of sales and operating expenses	**1,701**	1,472	**4,433**	4,326
Selling and administration expenses	**40**	37	**109**	99
Stock-based compensation	**79**	22	**177**	45
Depletion, depreciation and amortization	**311**	306	**913**	877
Interest - net *(notes 3, 5)*	**-**	13	**16**	47
Foreign exchange *(notes 3, 5)*	**(63)**	(84)	**(36)**	(60)
Other - net	**(57)**	1	**(52)**	5
	2,011	1,767	**5,560**	5,339
Earnings before income taxes	**752**	424	**1,897**	1,083
Income taxes				
Current	**78**	81	**220**	200
Future	**118**	46	**343**	102
	196	127	**563**	302
Net earnings	**$ 556**	$ 297	**$ 1,334**	$ 781
Earnings per share *(note 8)*				
Basic	**$ 1.31**	$ 0.70	**$ 3.15**	$ 1.84
Diluted	**$ 1.31**	$ 0.70	**$ 3.15**	$ 1.84
Weighted average number of common shares outstanding *(millions) (note 8)*				
Basic	**424.0**	423.6	**423.9**	423.2
Diluted	**424.0**	423.6	**423.9**	424.5

Consolidated Statements of Retained Earnings

(millions of dollars) (unaudited)	Three months ended Sept. 30		Nine months ended Sept. 30	
	2005	2004	**2005**	2004
Beginning of period	**$ 3,362**	$ 2,503	**$ 2,694**	$ 2,156
Net earnings	**556**	297	**1,334**	781
Dividends on common shares	**(60)**	(51)	**(170)**	(144)
Stock-based compensation - retroactive adoption	**-**	-	**-**	(44)
End of period	**$ 3,858**	$ 2,749	**$ 3,858**	$ 2,749

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 amounts as restated.

Consolidated Statements of Cash Flows

(millions of dollars) (unaudited)	Three months ended Sept. 30 **2005**	Three months ended Sept. 30 2004	Nine months ended Sept. 30 **2005**	Nine months ended Sept. 30 2004
Operating activities				
Net earnings	**$ 556**	$ 297	**$ 1,334**	$ 781
Items not affecting cash				
Accretion *(note 4)*	**8**	7	**25**	21
Depletion, depreciation and amortization	**311**	306	**913**	877
Future income taxes	**118**	46	**343**	102
Foreign exchange	**(66)**	(87)	**(42)**	(55)
Other	**17**	2	**15**	2
Settlement of asset retirement obligations	**(10)**	(11)	**(24)**	(24)
Change in non-cash working capital *(note 9)*	**171**	17	**41**	38
Cash flow - operating activities	**1,105**	577	**2,605**	1,742
Financing activities				
Bank operating loans financing - net	**(34)**	47	**(49)**	(24)
Long-term debt issue	**576**	205	**3,027**	1,666
Long-term debt repayment	**(782)**	(228)	**(3,175)**	(1,495)
Debt issue costs	**-**	-	**-**	(5)
Proceeds from exercise of stock options	**1**	1	**5**	17
Proceeds from monetization of financial instruments	**-**	-	**30**	-
Dividends on common shares	**(60)**	(51)	**(170)**	(144)
Change in non-cash working capital *(note 9)*	**9**	1	**(211)**	11
Cash flow - financing activities	**(290)**	(25)	**(543)**	26
Available for investing	**815**	552	**2,062**	1,768
Investing activities				
Capital expenditures	**(805)**	(556)	**(2,109)**	(1,597)
Corporate acquisitions	**-**	(102)	**-**	(102)
Asset sales	**13**	20	**70**	34
Other	**(21)**	2	**(23)**	(10)
Change in non-cash working capital *(note 9)*	**37**	11	**35**	(94)
Cash flow - investing activities	**(776)**	(625)	**(2,027)**	(1,769)
Increase (decrease) in cash and cash equivalents	**39**	(73)	**35**	(1)
Cash and cash equivalents at beginning of period	**3**	75	**7**	3
Cash and cash equivalents at end of period	**$ 42**	$ 2	**$ 42**	$ 2

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 amounts as restated.

Notes to the Consolidated Financial Statements

Nine months ended September 30, 2005 *(unaudited)*

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 1 Segmented Financial Information

	Upstream		Midstream				Refined Products		Corporate and Eliminations [2]		Total	
			Upgrading		Infrastructure and Marketing							
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004
Three months ended September 30 [1]												
Sales and operating revenues, net of royalties	**$ 1,176**	$ 817	**$ 328**	$ 308	**$ 1,721**	$ 1,564	**$ 716**	$ 515	**$ (1,178)**	$ (1,013)	**$ 2,763**	$ 2,191
Costs and expenses												
Operating, cost of sales, selling and general	**262**	255	**283**	268	**1,665**	1,518	**660**	479	**(1,107)**	(988)	**1,763**	1,532
Depletion, depreciation and amortization	**280**	278	**6**	5	**5**	6	**14**	9	**6**	8	**311**	306
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**-**	13	**-**	13
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(63)**	(84)	**(63)**	(84)
	542	533	**289**	273	**1,670**	1,524	**674**	488	**(1,164)**	(1,051)	**2,011**	1,767
Earnings (loss) before income taxes	**634**	284	**39**	35	**51**	40	**42**	27	**(14)**	38	**752**	424
Current income taxes	**47**	59	**4**	-	**(3)**	5	**(1)**	4	**31**	13	**78**	81
Future income taxes	**142**	64	**8**	11	**20**	9	**16**	5	**(68)**	(43)	**118**	46
Net earnings	**$ 445**	$ 161	**$ 27**	$ 24	**$ 34**	$ 26	**$ 27**	$ 18	**$ 23**	$ 68	**$ 556**	$ 297
Capital expenditures - Three months ended September 30	**$ 701**	$ 509	**$ 38**	$ 12	**$ 11**	$ 5	**$ 57**	$ 29	**$ 6**	$ 8	**$ 813**	$ 563
Nine months ended September 30 [1]												
Sales and operating revenues, net of royalties	**$ 3,040**	$ 2,398	**$ 1,074**	$ 767	**$ 4,673**	$ 4,671	**$ 1,713**	$ 1,332	**$ (3,043)**	$ (2,746)	**$ 7,457**	$ 6,422
Costs and expenses												
Operating, cost of sales, selling and general	**751**	720	**727**	662	**4,459**	4,510	**1,577**	1,236	**(2,847)**	(2,653)	**4,667**	4,475
Depletion, depreciation and amortization	**831**	794	**15**	14	**16**	16	**34**	27	**17**	26	**913**	877
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**16**	47	**16**	47
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(36)**	(60)	**(36)**	(60)
	1,582	1,514	**742**	676	**4,475**	4,526	**1,611**	1,263	**(2,850)**	(2,640)	**5,560**	5,339
Earnings (loss) before income taxes	**1,458**	884	**332**	91	**198**	145	**102**	69	**(193)**	(106)	**1,897**	1,083
Current income taxes	**169**	122	**13**	-	**(14)**	31	**(3)**	11	**55**	36	**220**	200
Future income taxes	**298**	161	**88**	25	**83**	17	**40**	14	**(166)**	(115)	**343**	102
Net earnings (loss)	**$ 991**	$ 601	**$ 231**	$ 66	**$ 129**	$ 97	**$ 65**	$ 44	**$ (82)**	$ (27)	**$ 1,334**	$ 781
Capital employed - As at September 30	**$ 8,005**	$ 7,409	**$ 489**	$ 487	**$ 670**	$ 390	**$ 402**	$ 372	**$ (290)**	$ (262)	**$ 9,276**	$ 8,396
Capital expenditures - Nine months ended September 30	**$ 1,899**	$ 1,493	**$ 85**	$ 38	**$ 24**	$ 12	**$ 105**	$ 53	**$ 14**	$ 19	**$ 2,127**	$ 1,615
Total assets - As at September 30	**$ 11,920**	$ 10,718	**$ 806**	$ 698	**$ 1,042**	$ 718	**$ 783**	$ 647	**$ 161**	$ 120	**$14,712**	$ 12,901

[1] 2004 amounts as restated. Refer to Note 5.

[2] Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.

Note 2 Significant Accounting Policies

The interim consolidated financial statements of Husky Energy Inc. (“Husky” or “the Company”) have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2004, except as noted below. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Company’s annual report for the year ended December 31, 2004. Certain prior years’ amounts have been reclassified to conform with current presentation.

Note 3 Change in Accounting Policies

Financial Instruments

Effective January 1, 2005, the Company retroactively adopted the revised recommendations of the Canadian Institute of Chartered Accountants (“CICA”) section 3860, “Financial Instruments – Disclosure and Presentation”, on the classification of obligations that must or could be settled with an entity’s own equity instruments. The new recommendations resulted in the Company’s capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs are classified outside of shareholders’ equity. The return on the capital securities is a charge to earnings. Note 5 discloses the impact of the adoption of the revised recommendations of CICA section 3860 on the consolidated financial statements.

Note 4 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Nine months ended Sept. 30	
	2005	2004
Asset retirement obligations at beginning of period	**$ 509**	$ 432
Liabilities incurred	**13**	16
Liabilities disposed	**(7)**	-
Liabilities settled	**(24)**	(24)
Accretion	**25**	21
Asset retirement obligations at end of period	**$ 516**	$ 445

At September 30, 2005, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.0 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend up to 50 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 to 6.4 percent.

Note 5 Long-term Debt

	Maturity	Sept. 30 2005	Dec. 31 2004	Sept. 30 2005	Dec. 31 2004
		Cdn $ Amount		*U.S. $ Amount*	
Long-term debt					
Syndicated credit facility		**$ -**	$ 70	**$ -**	$ -
Bilateral credit facilities		**-**	40	**-**	-
7.125% notes	2006	**174**	181	**150**	150
8.90% capital securities	2008	**261**	271	**225**	225
6.25% notes	2012	**465**	481	**400**	400
7.55% debentures	2016	**232**	241	**200**	200
6.15% notes	2019	**348**	361	**300**	300
Private placement notes	2005	**17**	18	**15**	15
8.45% senior secured bonds	2006-12	**99**	140	**85**	117
Medium-term notes	2007-9	**300**	300	**-**	-
Total long-term debt		**1,896**	2,103	**$ 1,375**	$ 1,407
Amount due within one year		**(46)**	(56)		
		$ 1,850	$ 2,047		

Interest - net consisted of:

	Three months ended Sept. 30 2005	Three months ended Sept. 30 2004	Nine months ended Sept. 30 2005	Nine months ended Sept. 30 2004
Long-term debt	**$ 35**	$ 32	**$ 105**	$ 100
Short-term debt	**1**	-	**3**	2
	36	32	**108**	102
Amount capitalized	**(36)**	(19)	**(91)**	(54)
	-	13	**17**	48
Interest income	**-**	-	**(1)**	(1)
	$ -	$ 13	**$ 16**	$ 47

Foreign exchange consisted of:

	Three months ended Sept. 30 2005	Three months ended Sept. 30 2004	Nine months ended Sept. 30 2005	Nine months ended Sept. 30 2004
Gain on translation of U.S. dollar denominated long-term debt	**$ (89)**	$ (109)	**$ (58)**	$ (63)
Cross currency swaps	**22**	22	**16**	8
Other (gains) losses	**4**	3	**6**	(5)
	$ (63)	$ (84)	**$ (36)**	$ (60)

Credit Facilities

In March 2005, Husky increased its revolving syndicated credit facility from $950 million to $1 billion.

Capital Securities

The Company retroactively adopted CICA recommendations resulting in the Company's capital securities being classified as liabilities instead of equity. The revision was effective January 1, 2005 and resulted in the following changes to the Company's consolidated financial statements:

Consolidated Balance Sheet - As at December 31, 2004	As Reported	Change	As Restated
Assets			
Other assets	$ 106	$ 2	$ 108
Liabilities and Shareholders' Equity			
Accounts payable and accrued liabilities	1,489	9	1,498
Long-term debt	1,776	271	2,047
Capital securities and accrued return	278	(278)	-

Consolidated Statement of Earnings - Nine months ended September 30, 2004	As Reported	Change	As Restated
Interest - net	$ 27	$ 20	$ 47
Foreign exchange	(53)	(7)	(60)
Future income taxes	108	(6)	102
Net earnings	788	(7)	781

Note 6 Commitments and Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity. In the third quarter of 2005, a lawsuit was settled with proceeds received and the resulting gain was recognized in earnings and recorded in other - net.

Note 7 Share Capital

The Company's authorized share capital consists of an unlimited number of no par value common and preferred shares.

Common Shares

Changes to issued common shares were as follows:

	Nine months ended September 30			
	2005		2004	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of period	423,736,414	$ 3,506	422,175,742	$ 3,457
Stock-based compensation - adoption	-	-	-	23
Exercised - options and warrants	375,136	16	1,497,522	24
Balance at September 30	**424,111,550**	**$ 3,522**	423,673,264	$ 3,504

Stock Options

A summary of the status of the Company's stock option plan is presented below:

	Nine months ended September 30			
	2005		2004	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	9,964	$ 22.61	4,597	$ 13.88
Granted	405	$ 43.19	7,988	$ 24.90
Exercised for common shares	(346)	$ 15.62	(1,287)	$ 13.09
Surrendered for cash	(2,241)	$ 18.53	(880)	$ 13.24
Forfeited	(441)	$ 24.01	(167)	$ 22.16
Outstanding, September 30	**7,341**	**$ 25.23**	10,251	$ 22.48
Options exercisable at September 30	**1,557**	**$ 23.47**	1,712	$ 13.09

	September 30, 2005				
	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$14.22 - $14.99	132	$ 14.50	2	79	$ 14.49
$15.00 - $23.99	326	$ 18.75	3	89	$ 17.05
$24.00 - $24.99	6,202	$ 24.38	4	1,383	$ 24.38
$25.00 - $39.99	451	$ 32.57	4	6	$ 27.21
$40.00 - $49.18	230	$ 49.18	5	-	$ -
	7,341	**$ 25.23**	**4**	**1,557**	**$ 23.47**

Note 8 Earnings per Common Share

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2005	2004	**2005**	2004
Net earnings and net earnings available to common shareholders	**$ 556**	$ 297	**$ 1,334**	$ 781
Weighted average number of common shares outstanding Basic *(millions)*	**424.0**	423.6	**423.9**	423.2
Effect of dilutive stock options and warrants	**-**	-	**-**	1.3
Weighted average number of common shares outstanding Diluted *(millions)*	**424.0**	423.6	**423.9**	424.5
Earnings per share				
Basic	**$ 1.31**	$ 0.70	**$ 3.15**	$ 1.84
Diluted	**$ 1.31**	$ 0.70	**$ 3.15**	$ 1.84

Note 9 Cash Flows - Change in Non-cash Working Capital

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2005	2004	**2005**	2004
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ (93)**	$ (16)	**$ (113)**	$ 33
Inventories	**(36)**	(17)	**(176)**	(89)
Prepaid expenses	**15**	4	**(3)**	(12)
Accounts payable and accrued liabilities	**331**	58	**157**	23
Change in non-cash working capital	**217**	29	**(135)**	(45)
Relating to:				
Financing activities	**9**	1	**(211)**	11
Investing activities	**37**	11	**35**	(94)
Operating activities	**$ 171**	$ 17	**$ 41**	$ 38
b) Other cash flow information:				
Cash taxes paid (received)	**$ (14)**	$ 35	**$ 145**	$ 187
Cash interest paid	**$ 30**	$ 31	**$ 103**	$ 104

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2005	2004	**2005**	2004
Employer current service cost	**$ 4**	$ 4	**$ 13**	$ 12
Interest cost	**2**	2	**7**	6
Expected return on plan assets	**(2)**	(2)	**(6)**	(6)
Amortization of net actuarial losses	**1**	-	**2**	1
	$ 5	$ 4	**$ 16**	$ 13

Note 11 Financial Instruments and Risk Management

Unrecognized gains (losses) on derivative instruments were as follows:

	Sept. 30 2005	Dec. 31 2004
Commodity price risk management		
Natural gas	**$ (8)**	$ (9)
Power consumption	**2**	(1)
Interest rate risk management		
Interest rate swaps	**22**	52
Foreign currency risk management		
Foreign exchange contracts	**(38)**	(30)

Commodity Price Risk Management

- Natural Gas Production

At September 30, 2005, the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for October to December 2005 at an average price of U.S. $1.92 per mcf. During the first nine months of 2005, the impact was a loss of $9 million.

- Power Consumption

At September 30, 2005, the Company had hedged power consumption of 49,680 MWh from October to December 2005 at an average fixed price of $49.94 per MWh. The impact of the hedge program during the first nine months of 2005 was a gain of $1 million.

- Natural Gas Contracts

At September 30, 2005, the unrecognized gains (losses) on external offsetting physical purchase and sale natural gas contracts were as follows:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	30,741	$ 29
Physical sale contracts	(30,741)	$ (28)

Interest Rate Risk Management

In May 2005, the Company unwound the following interest rate swaps:

Debt	Swap Amount	Swap Maturity	Swap Rate *(percent)*
6.15% notes	U.S. $300	June 15, 2019	U.S. LIBOR + 63 bps

The proceeds of $30 million have been deferred and are being amortized to income over the remaining term of the underlying debt.

During the first nine months of 2005, the Company realized a gain of $11 million from interest rate risk management activities.

Foreign Currency Risk Management

During the third quarter of 2005, the Company entered into the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*
6.25% notes	U.S. $75	$90	June 15, 2012	5.65
6.25% notes	U.S. $50	$59	June 15, 2012	5.67

During the first nine months of 2005, the Company realized a $4 million loss from all foreign currency risk management activities.

During the first nine months of 2005, Husky recognized a gain of $8 million from its long-dated forwards, which fixed the exchange rate on U.S. dollar sales and were unwound in November 2004.

Sale of Accounts Receivable

The Company has a securitization program to sell, on a revolving basis, accounts receivable to a third party up to $350 million. As at September 30, 2005, $350 million in outstanding accounts receivable had been sold under the program.

Terms and 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
MW	megawatt
MWh	megawatt hour
NGL	natural gas liquids
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
NIT	NOVA Inventory Transfer (1)
LIBOR	London Interbank Offered Rate
CDOR	Certificate of Deposit Offered Rate
SEDAR	System for Electronic Document Analysis and Retrieval
FPSO	Floating production, storage and offloading vessel
OPEC	Organization of Petroleum Exporting Countries
WCSB	Western Canada Sedimentary Basin
SAGD	Steam-assisted gravity drainage
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
Cash Flow from Operations	Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital
Equity	Shares and retained earnings
Total Debt	Long-term debt including current portion and bank operating loans
hectare	1 hectare is equal to 2.47 acres
wildcat well	Exploratory well drilled in an area where no production exists
feedstock	Raw materials which are processed into petroleum products

(1) *NOVA Inventory Transfer is an exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline.*

Natural gas converted on the basis that six mcf equals one barrel of oil.

In this report, the terms “Husky Energy Inc.”, “Husky”, “we”, “our” or “the Company” mean Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis.

Husky Energy Inc. will host a conference call for analysts and investors on Wednesday, October 19, 2005 at 4:15 p.m. Eastern time to discuss Husky's third quarter results which will be released after market close on October 18, 2005. To participate, please dial 1-800-818-6210 beginning at 4:05 p.m. Eastern time. Mr. John C.S. Lau, President & Chief Executive Officer, Donald R. Ingram, Senior Vice President, Midstream & Refined Products and Neil D. McGee, Vice President & Chief Financial Officer will be participating in the call.

We appreciate your interest in Husky Energy and look forward to your participation in our conference call.

Those who are unable to listen to the call live may listen to a recording by dialing 1-800-558-5253 one hour after the completion of the call, approximately 6:15 p.m. Eastern time, then dialing reservation number 21259641. The PostView will be available until Saturday, November 19, 2005.

Media are invited to participate in the call on a listen-only basis by dialing 1-800-806-5839 beginning at 4:05 p.m. Eastern time.

- 30 -

For further information, please contact:

Investor Relations
Mr. Colin Luciuk
Manager, Investor Relations
Husky Energy Inc. Tel: (403) 750-4938

707 - 8th Avenue S.W., Box 6525, Station D, Calgary, Alberta, Canada T2P 3G7
Telephone: (403) 298-6111 Facsimile: (403) 298-6515
Website: www.huskyenergy.ca e-mail: Investor.Relations@huskyenergy.ca