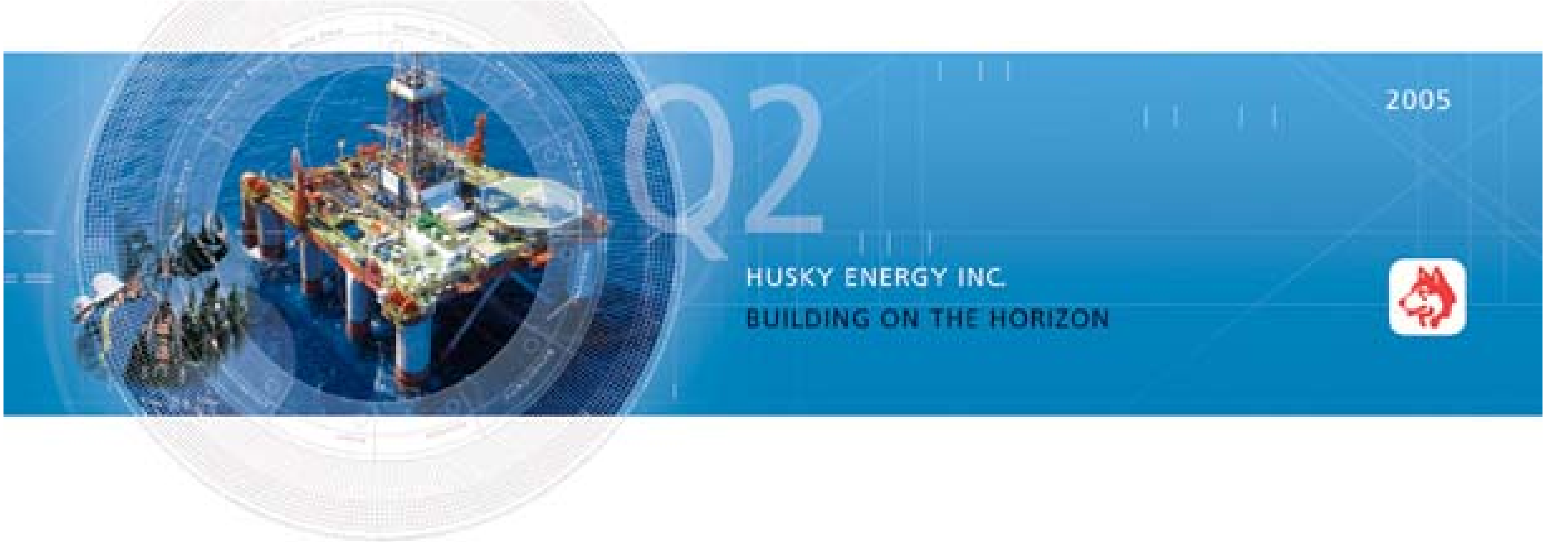
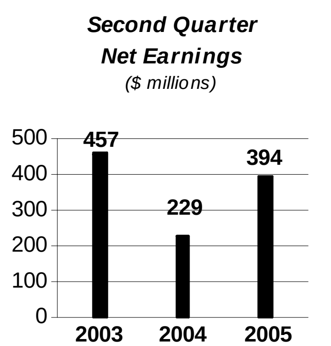
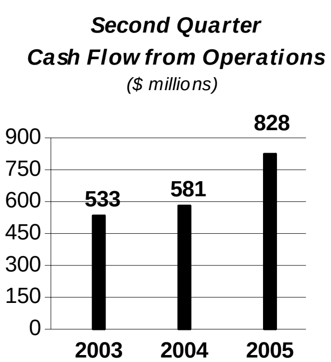
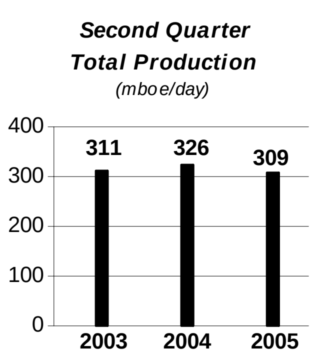


HUSKY ENERGY ANNOUNCES 2005 SECOND QUARTER RESULTS







Calgary, Alberta – Husky Energy Inc. reported net earnings of $394 million or $0.93 per share (diluted) in the second quarter of 2005, a 72 percent increase over net earnings of $229 million or $0.54 per share (diluted) in the second quarter of 2004. Included in net earnings for the second quarter of 2005 are net charges of $54 million related to stock-based compensation and $14 million related to U.S. dollar denominated debt translation. Cash flow from operations was $828 million or $1.95 per share (diluted) in the second quarter of 2005, a 43 percent increase compared with $581 million or $1.37 per share (diluted) in the second quarter of 2004. Sales and operating revenues, net of royalties, were $2.5 billion in the second quarter of 2005, a 13 percent increase compared with $2.2 billion in the second quarter of 2004.

"We are pleased with Husky's second quarter record solid cash flow from operations," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "In this strong commodity price environment, Husky's financial and operational strength continues to benefit from our integration, quality asset base and strong financial discipline."

Production in the second quarter of 2005 was 308,900 barrels of oil equivalent per day, compared with 326,400 barrels of oil equivalent per day in the second quarter of 2004. Total crude oil and natural gas liquids production was 194,000 barrels per day, compared with 212,200 barrels per day in the second quarter of 2004. Natural gas production was 689.3 million cubic feet per day, compared with 685.4 million cubic feet per day in the second quarter of 2004.

"In Western Canada, production was affected by unseasonably wet weather," said Mr. Lau. "An extended spring break-up followed by heavy rainfall throughout Alberta caused delays in the tie-in of our natural gas program and in the development of Husky's heavy oil reserves."

Operational issues continued to affect production at Terra Nova during the quarter. Our share of production for the quarter was 13,500 barrels per day compared to 15,700 barrels per day in the second quarter of 2004.

Husky made progress on several initiatives. A sailaway ceremony for the *SeaRose FPSO* was held in early July in Marystown, Newfoundland and Labrador. The vessel will depart Marystown in early August and, after a series of tests in Mortier Bay, sail to the White Rose oil field.

During the third quarter, the *SeaRose FPSO* will be connected to the subsea production system. The White Rose project is expected to be on schedule to achieve first oil before year-end and add approximately 67,500 barrels per day of light oil production net to Husky when it attains full productive capacity.

Drilling at the Lewis Hill prospect in the South Whale Basin offshore Newfoundland commenced on July 11, 2005. Husky has a 100 percent working interest in this location. After completion of drilling at Lewis Hill, two wells will be drilled at the White Rose oil field with the objective of delineating reserves beyond those currently under development.

In the South China Sea, the Wushi 17-1-1 well was drilled in Block 23/15 during the second quarter in the Beibu Gulf and encountered hydrocarbons. The well data are currently being evaluated. Husky plans to immediately drill a second exploration well on the adjacent Block 23/20. A rig has been secured for the deep water location in Block 29/26 and drilling is expected to commence by the end of 2005 or in early 2006.

At Husky's Tucker thermal oil sands project, facility construction continues on schedule. During the second quarter, work progressed well on the drilling program for 30 horizontal well pairs. At the end of the second quarter, overall facility construction was 25 percent complete. The Sunrise thermal oil sands project conceptual studies for marketing options are underway and regulatory project approval is expected by the end of 2005 or early 2006.

Husky's net earnings for the first six months of 2005 were $778 million or $1.84 per share (diluted), compared with $484 million or $1.14 per share (diluted) for the same period in 2004. Cash flow from operations for the first six months of 2005 was $1,644 million or $3.88 per share (diluted), compared with $1,157 million or $2.72 per share (diluted) for the same period of 2004.

Production in the first six months of 2005 was 314,200 barrels of oil equivalent per day, compared with 325,400 barrels of oil equivalent per day in the same period in 2004. Total crude oil and natural gas liquids production was 200,400 barrels per day, compared with 212,100 barrels per day in the first six months of 2004. Natural gas production was 682.8 million cubic feet per day, compared with 679.5 million cubic feet per day in the first six months of 2004. Production levels in Western Canada for the first six months of 2005 were affected by a lengthy spring break-up and unseasonably wet weather.

MANAGEMENT'S DISCUSSION AND ANALYSIS

July 19, 2005

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							
	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30
(millions of dollars, except per share amounts and ratios)	**2005**	2005	2004	2004	2004	2004	2003	2003
Sales and operating revenues, net of royalties	**$ 2,493**	$ 2,201	$ 2,018	$ 2,191	$ 2,210	$ 2,021	$ 1,800	$ 1,871
Segmented earnings								
Upstream	**$ 307**	$ 239	$ 112	$ 161	$ 204	$ 236	$ 169	$ 215
Midstream	**130**	169	77	50	53	60	46	41
Refined Products	**20**	18	(3)	18	21	5	6	22
Corporate and eliminations	**(63)**	(42)	39	68	(49)	(46)	31	(42)
Net earnings	**$ 394**	$ 384	$ 225	$ 297	$ 229	$ 255	$ 252	$ 236
Per share - Basic	**$ 0.93**	$ 0.91	$ 0.53	$ 0.70	$ 0.54	$ 0.60	$ 0.60	$ 0.56
- Diluted	**0.93**	0.91	0.53	0.70	0.54	0.60	0.59	0.56
Cash flow from operations	**828**	816	469	571	581	576	561	597
Per share - Basic	**1.95**	1.93	1.11	1.34	1.37	1.36	1.33	1.42
- Diluted	**1.95**	1.93	1.11	1.34	1.37	1.36	1.32	1.42
Dividends declared per common share	**0.14**	0.12	0.12	0.12	0.12	0.10	0.10	0.10
Special dividend per common share	**-**	-	0.54	-	-	-	-	1.00
Total assets	**14,058**	13,690	13,240	12,901	12,542	12,317	11,949	11,771
Total long-term debt including current portion	**2,192**	2,290	2,103	2,096	2,229	1,993	1,989	2,279
Return on equity [2] *(percent)*	**20.2**	18.3	17.0	17.7	16.8	21.8	26.4	27.2
Return on average capital employed [2] *(percent)*	**15.3**	13.9	13.0	13.4	12.7	16.2	18.9	19.0

(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				
		June 30 2005	March 31 2005	Dec. 31 2004	Sept. 30 2004	June 30 2004
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**31.7**	31.9	32.9	33.1	32.9
Medium crude oil		**30.6**	32.4	33.7	34.5	35.6
Heavy crude oil		**100.9**	110.4	113.8	108.8	107.4
		163.2	174.7	180.4	176.4	175.9
East Coast Canada						
Terra Nova - light crude oil		**13.5**	13.7	10.1	11.5	15.7
China						
Wenchang - light crude oil		**17.3**	18.5	17.9	20.2	20.6
		194.0	206.9	208.4	208.1	212.2
Natural gas	*(mmcf/day)*	**689.3**	676.2	697.4	700.4	685.4
Total	*(mboe/day)*	**308.9**	319.6	324.6	324.8	326.4

Crude oil and natural gas production in the second quarter of 2005 was 308.9 mboe/day compared with 319.6 mboe/day in the previous quarter and 326.4 mboe/day in the second quarter of 2004.

Production in the second quarter of 2005 compared with the first quarter of 2005 decreased primarily as a result of 9.5 mbbls/day lower heavy oil production from the Lloydminster region resulting primarily from exceptionally wet weather and 1.2 mbbls/day lower production from the Wenchang, China oil field from natural reservoir declines. Lower crude oil production in the second quarter of 2005 compared with the first quarter of 2005 was partially offset by higher production of natural gas and NGL.

Natural gas production volume averaged 13.1 mmcf/day higher in the second quarter of 2005 compared with the first quarter of 2005. Natural gas production was affected by a major turnaround at the Ram River gas plant and wet weather during the quarter that restricted our access to drilling operations in the foothills and deep basin area of Alberta and British Columbia. At the end of the quarter a number of wells in these areas were temporarily suspended from drilling and completion activities.

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

		Six months ended June 30	Forecast	Six months ended June 30	Year ended December 31
		2005	2005	2004	2004
Crude oil & NGL	*(mbbls/day)*				
Light crude oil & NGL		**63.3**	64 - 71	69.8	66.2
Medium crude oil		**31.5**	32 - 36	35.8	35.0
Heavy crude oil		**105.6**	112 - 120	106.5	108.9
		200.4	208 - 227	212.1	210.1
Natural gas	*(mmcf/day)*	**682.8**	700 - 740	679.5	689.2
Total barrels of oil equivalent	*(mboe/day)*	**314.2**	325 - 350	325.4	325.0

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 in non-conventional production from oil sands in Western Canada, offshore Canada's East Coast and international properties in China and Indonesia. 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 June 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	50 mbbls/day [2]	100%	2009 - 2010

[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

At Marystown, Newfoundland and Labrador, construction of the *SeaRose* FPSO is complete and 24 of the 42 topside modules have been turned over to us as complete and ready for testing and commissioning. The crew of the *SeaRose* FPSO is nearing the end of training at the Marine Institute in St. John's and is on site. Sailaway is expected to occur in early August.

At the White Rose oil field, drilling and completion of the 10 wells that will be operating at first oil is progressing. Three water injection wells, one gas injection well and one production well have been completed and completion of three water injection wells and two production wells is currently underway. The flexible production and gas injection flow lines are being installed during the third quarter.

Tucker

During the second quarter of 2005, drilling operations commenced from two drilling pads. At pad "A" the intermediate casing strings have been set on all eight SAGD well pairs. Drilling of the horizontal section for these wells commenced in early July. At pad "B" the surface casing has been set for all 12 SAGD well pairs and currently the intermediate casing strings are being drilled. Construction of pad "C" is underway where 10 SAGD well pairs will be drilled. Facility construction is progressing with equipment and modules being delivered to the field. Construction on the control complex building has commenced. Overall facility construction is 25 percent complete. The project remains on schedule for commissioning work to commence in the second half of 2006.

Sunrise

At Sunrise, the regulatory approval process is continuing; regulatory approval for the project is expected in late 2005 or early 2006. Project work continued on the conceptual design and the marketing options for the project.

Exploration

- Western Canada

During the second quarter of 2005, we drilled 51 exploratory wells (36 net) resulting in 36 (21 net) natural gas completions and 10 (10 net) oil completions.

Exploration activity in our key areas in the foothills, deep basin and northwestern plains of Alberta and British Columbia was restricted due to spring break-up and exceptionally wet weather.

- Northwest Territories

During the second quarter of 2005, we became the operator of Exploration License 387 on which the 2004 Summit Creek B-44 discovery well was drilled and in which we have a 29.5 percent working interest. We are planning to shoot a 200 kilometre seismic program in this area in July and further delineation drilling in the winter.

- East Coast

The Rowan Gorilla VI jack-up rig has been contracted to drill the Lewis Hill prospect in the South Whale Basin (100 percent working interest). The well spudded in early July.

In the northern Jeanne d'Arc Basin, Husky will be shooting a 700 square kilometre seismic program over our exploration blocks north of the White Rose oil field. This program is expected to commence in the third quarter.

- China

In the Beibu Gulf, the COSL 931 shallow-water jack-up rig drilled the Wushi 17-1-1 prospect on Block 23/15. The rig will move south to the 32-1-1 prospect on Block 23/20 contiguous to the 23/15 block.

A deep-water drill ship has been contracted to drill a prospect on Block 29/26 in the Pearl River Mouth Basin. The site survey for the location is currently being conducted and the well is expected to spud in the fourth quarter of 2005 or early 2006.

- Indonesia

In Indonesia, work is progressing toward establishing a natural gas contract for two natural gas fields yet to be developed in the Madura Strait, offshore Java. In addition, seismic studies on the Madura exploration prospects are underway.

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 for mid 2006 with connections to be made in September 2005 during the 30 day scheduled plant turnaround. The projects are expected to cost approximately $60 million.

REFINED PRODUCTS

Prince George Refinery

The refinery is currently being modified to produce low sulphur fuels. The project is in the construction phase. Production of desulphurized gasoline and diesel is expected to commence in July 2005 and March 2006, respectively. The project is expected to cost approximately $93 million.

Lloydminster Ethanol Plant

At Lloydminster, Saskatchewan we are constructing a 130 million litre per year ethanol plant. The project is in the construction phase and is scheduled for completion in early 2006. The project is expected to cost approximately $120 million.

Minnedosa Ethanol Plant

At Minnedosa, Manitoba we are currently considering plans to increase the capacity of the existing plant from 10 million litres to 130 million litres per year.

Husky established an endowment of $1 million at the University of Manitoba for the creation of two research chairs in biofuels with a focus on ethanol. We will also provide an additional $1.625 million over five years which the university will seek to augment through government support programs.

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 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				
		June 30 2005	March 31 2005	Dec. 31 2004	Sept. 30 2004	June 30 2004
WTI crude oil [1]	*(U.S. $/bbl)*	**$ 53.17**	$ 49.84	$ 48.28	$ 43.88	$ 38.32
Canadian par light crude 0.3% sulphur	*($/bbl)*	**66.43**	62.02	58.01	56.61	50.99
Lloyd @ Lloydminster heavy crude oil	*($/bbl)*	**27.95**	22.62	25.31	35.47	28.09
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**6.73**	6.27	7.11	5.76	5.97
NIT natural gas	*($/GJ)*	**6.99**	6.34	6.72	6.32	6.45
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.27**	19.57	19.82	12.86	11.82
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.804**	0.815	0.819	0.765	0.736

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

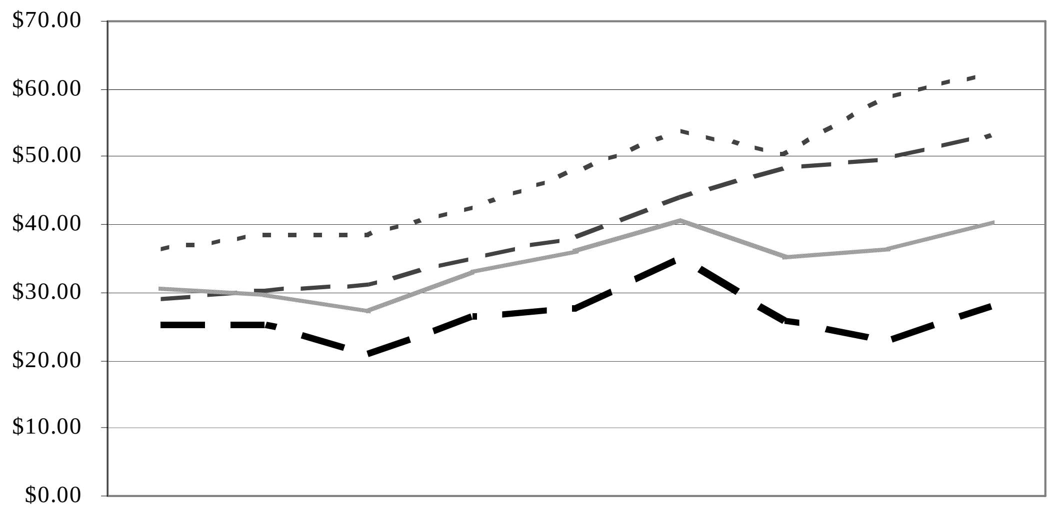
COMMODITY PRICE RISK

Our earnings depend largely on the profitability of our upstream business segment which is 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)

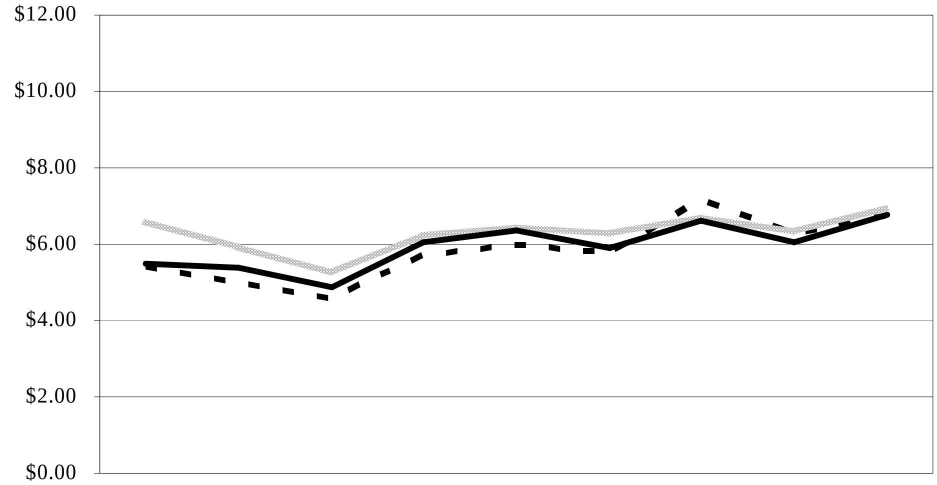


	Q2-03	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04	Q1-05	Q2-05
West Texas Intermediate ("WTI") (U.S. $)	$28.91	$30.20	$31.18	$35.15	$38.32	$43.88	$48.28	$49.84	$53.17
Husky average light crude oil price (C $)	$36.45	$38.49	$38.55	$42.50	$47.99	$53.94	$50.29	$58.94	$62.49
Husky average medium crude oil price (C $)	$30.48	$29.68	$27.25	$32.97	$35.98	$40.59	$35.06	$36.50	$40.45
Husky average heavy crude oil price (C $)	$25.13	$25.13	$20.84	$26.38	$27.54	$34.92	$25.81	$22.53	$27.95

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.

Natural Gas

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



	Q2-03	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04	Q1-05	Q2-05
NYMEX natural gas (U.S. $/mmbtu)	$5.39	$4.97	$4.58	$5.69	$5.97	$5.76	$7.11	$6.27	$6.73
NIT natural gas (C $/GJ)	$6.63	$5.97	$5.30	$6.26	$6.45	$6.32	$6.72	$6.34	$6.99
Husky average natural gas price (C $/mcf)	$5.50	$5.40	$4.87	$6.05	$6.38	$5.92	$6.64	$6.07	$6.76

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. 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 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 June 30, 2005, 78 percent or $1.7 billion of our long-term debt was denominated in U.S. dollars. The Cdn/U.S. exchange rate at the end of the second quarter of 2005 was $1.2256. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 59 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. 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 second 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*	76	0.18	50	0.12
NYMEX benchmark natural gas price [1]	*U.S. $0.20/mmbtu*	38	0.09	24	0.06
Light/heavy crude oil differential [2]	*Cdn $1.00/bbl*	(23)	(0.05)	(14)	(0.03)
Light oil margins	*Cdn $0.005/litre*	16	0.04	10	0.02
Asphalt margins	*Cdn $1.00/bbl*	7	0.02	5	0.01
Exchange rate (U.S. $ / Cdn $) [3]	*U.S. $0.01*	(53)	(0.13)	(36)	(0.08)

(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 $13 million in net earnings based on June 30, 2005 U.S. dollar denominated debt levels.*

(4) *Based on June 30, 2005 common shares outstanding of 424.0 million.*

RESULTS OF OPERATIONS

UPSTREAM

Upstream Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2005**	2004	**2005**	2004
Gross revenues	**$ 1,154**	$ 1,097	**$ 2,194**	$ 2,110
Royalties	**178**	182	**330**	340
Hedging	**-**	115	**-**	189
Net revenues	**976**	800	**1,864**	1,581
Operating and administration expenses	**249**	240	**489**	465
Depletion, depreciation and amortization	**278**	262	**551**	516
Income taxes	**142**	94	**278**	160
Earnings	**$ 307**	$ 204	**$ 546**	$ 440

Net Revenue Variance Analysis *(millions of dollars)*	Crude oil & NGL	Natural gas	Other	Total
Three months ended June 30, 2004	$ 480	$ 299	$ 21	$ 800
Price changes	96	23	-	119
Volume changes	(63)	2	-	(61)
Royalties	(3)	7	-	4
Hedging	114	1	-	115
Processing and sulphur	-	-	(1)	(1)
Three months ended June 30, 2005	**$ 624**	**$ 332**	**$ 20**	**$ 976**
Six months ended June 30, 2004	$ 948	$ 596	$ 37	$1,581
Price changes	156	22	-	178
Volume changes	(92)	(1)	-	(93)
Royalties	(8)	18	-	10
Hedging	193	(4)	-	189
Processing and sulphur	-	-	(1)	(1)
Six months ended June 30, 2005	**$ 1,197**	**$ 631**	**$ 36**	**$1,864**

Second Quarter

Upstream earnings were $103 million higher in the second quarter of 2005 than in the second quarter of 2004 as a result of the following factors:

- Higher crude oil and natural gas prices
- Hedging diverted $115 million in the second quarter of 2004; second quarter of 2005 commodity prices were not hedged
- Higher production of natural gas and NGL

Partially offset by:

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

Six Months

With the exception of income taxes, the factors that affected upstream performance in the first six months of 2005 compared with the first six months of 2004 were essentially the same as those during the second quarter of 2005 and 2004. The effective income tax rate was lower in the first six months of 2004 as a result of a cumulative benefit from a rate reduction enacted during the first quarter of 2004.

Unit Operating Costs

Unit operating costs were eight percent higher in the second quarter of 2005 compared with the same period in 2004 due to increased natural gas compression costs, higher natural gas well count, turnaround and production declines.

Unit Depletion, Depreciation and Amortization

Unit depletion, depreciation and amortization expense increased 12 percent in the second quarter of 2005 compared with the same period in 2004. The increase resulted from a higher capital base in 2005 as a result of the increased requirement for production maintenance capital for our properties in the Western Canada Sedimentary Basin, offshore operations requiring a higher proportion of capital and higher capital costs associated with purchase of reserves in place. In addition, the exceptionally wet weather restricted well completions, particularly in the Rocky Mountain foothills and deep basin area of Alberta and as a result reserves bookings were delayed.

Average Sales Prices		Three months ended June 30		Six months ended June 30	
		2005	2004	**2005**	2004
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 59.51**	$ 47.41	**$ 57.95**	$ 44.60
Medium crude oil		**40.45**	35.98	**38.42**	34.46
Heavy crude oil		**27.95**	27.54	**25.13**	26.96
Total average		**40.09**	35.12	**37.59**	33.77
Natural Gas	*($/mcf)*				
Average		**6.76**	6.38	**6.42**	6.22

Effective Royalty Rates [1]	Three months ended June 30		Six months ended June 30	
Percentage of upstream sales revenues	**2005**	2004	**2005**	2004
Crude oil & NGL	**13%**	13%	**13%**	13%
Natural gas	**20%**	23%	**20%**	22%
Total	**16%**	17%	**15%**	16%

[1] *Before commodity hedging.*

Upstream Revenue Mix [1]	Three months ended June 30		Six months ended June 30	
Percentage of upstream sales revenues, after royalties	**2005**	2004	**2005**	2004
Light crude oil & NGL	**31%**	28%	**31%**	28%
Medium crude oil	**10%**	11%	**10%**	11%
Heavy crude oil	**23%**	26%	**23%**	26%
Natural gas	**36%**	35%	**36%**	35%
	100%	100%	**100%**	100%

[1] *Before commodity hedging.*

OPERATING NETBACKS

Western Canada

Light Crude Oil Netbacks (1)	Three months ended June 30		Six months ended June 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 57.50**	$ 45.82	**$ 53.92**	$ 43.11
Royalties	**7.64**	8.83	**6.23**	7.99
Operating costs	**11.26**	9.30	**10.53**	9.07
Netback	**$ 38.60**	$ 27.69	**$ 37.16**	$ 26.05

Medium Crude Oil Netbacks (1)	Three months ended June 30		Six months ended June 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 40.61**	$ 35.98	**$ 38.49**	$ 34.51
Royalties	**6.98**	6.29	**6.69**	5.95
Operating costs	**10.05**	9.66	**10.30**	9.65
Netback	**$ 23.58**	$ 20.03	**$ 21.50**	$ 18.91

Heavy Crude Oil Netbacks (1)	Three months ended June 30		Six months ended June 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 28.09**	$ 27.65	**$ 25.28**	$ 27.09
Royalties	**3.09**	3.13	**2.62**	2.96
Operating costs	**9.48**	9.24	**9.35**	9.31
Netback	**$ 15.52**	$ 15.28	**$ 13.31**	$ 14.82

Natural Gas Netbacks (2)	Three months ended June 30		Six months ended June 30	
Per mcfge	**2005**	2004	**2005**	2004
Sales revenues	**$ 6.81**	$ 6.36	**$ 6.50**	$ 6.19
Royalties	**1.51**	1.51	**1.45**	1.43
Operating costs	**1.00**	0.87	**0.97**	0.83
Netback	**$ 4.30**	$ 3.98	**$ 4.08**	$ 3.93

Total Western Canada Upstream Netbacks (1)	Three months ended June 30		Six months ended June 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 37.81**	$ 34.84	**$ 35.36**	$ 33.75
Royalties	**6.49**	6.45	**5.91**	6.06
Operating costs	**8.26**	7.77	**8.19**	7.69
Netback	**$ 23.06**	$ 20.62	**$ 21.26**	$ 20.00

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

Terra Nova Crude Oil Netbacks	Three months ended June 30		Six months ended June 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 58.11**	$ 47.69	**$ 59.42**	$ 45.37
Royalties	**2.86**	1.16	**2.94**	1.12
Operating costs	**3.29**	2.86	**3.61**	2.82
Netback	**$ 51.96**	$ 43.67	**$ 52.87**	$ 41.43

Wenchang Crude Oil Netbacks	Three months ended June 30		Six months ended June 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 66.11**	$ 48.24	**$ 62.42**	$ 44.77
Royalties	**6.16**	4.81	**5.78**	4.51
Operating costs	**2.39**	2.02	**2.38**	2.10
Netback	**$ 57.56**	$ 41.41	**$ 54.26**	$ 38.16

Total Upstream Segment Netbacks (1)	Three months ended June 30		Six months ended June 30	
Per boe	**2005**	2004	**2005**	2004
Sales revenues	**$ 40.29**	$ 36.31	**$ 37.94**	$ 35.04
Royalties	**6.31**	6.09	**5.77**	5.71
Operating costs	**7.74**	7.17	**7.67**	7.10
Netback	**$ 26.24**	$ 23.05	**$ 24.50**	$ 22.23

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

MIDSTREAM

Upgrading Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2005**	2004	**2005**	2004
Gross margin		**$ 195**	$ 83	**$ 402**	$ 168
Operating costs		**53**	53	**103**	105
Other recoveries		**(2)**	(1)	**(3)**	(2)
Depreciation and amortization		**4**	4	**9**	9
Income taxes		**43**	8	**89**	14
Earnings		**$ 97**	$ 19	**$ 204**	$ 42
Selected operating data:					
Upgrader throughput (1)	*(mbbls/day)*	**71.3**	56.6	**71.7**	63.4
Synthetic crude oil sales	*(mbbls/day)*	**60.1**	44.1	**62.0**	51.1
Upgrading differential	*($/bbl)*	**$ 31.05**	$ 17.10	**$ 31.51**	$ 15.25
Unit margin	*($/bbl)*	**$ 35.64**	$ 20.76	**$ 35.80**	$ 18.02
Unit operating cost (2)	*($/bbl)*	**$ 8.12**	$ 10.31	**$ 7.91**	$ 9.12

(1) Throughput includes diluent returned to the field.

(2) Based on throughput.

Upgrading Earnings Variance Analysis

(millions of dollars)

Three months ended June 30, 2004	$	19
Volume		30
Margin		82
Operating costs - energy related		(6)
Operating costs - non-energy related		6
Other		1
Income taxes		(35)
Three months ended June 30, 2005	**$**	**97**
Six months ended June 30, 2004	$	42
Volume		35
Margin		199
Operating costs - energy related		(5)
Operating costs - non-energy related		7
Other		1
Income taxes		(75)
Six months ended June 30, 2005	**$**	**204**

Second Quarter

Upgrading earnings increased in the second quarter of 2005 by $78 million compared with the second quarter of 2004 due to:

- Wider upgrading differential
- Higher sales volume of synthetic crude oil
- Lower non-energy related unit operating costs

Partially offset by:

- Higher energy related operating costs
- Higher income taxes due to higher earnings

Six Months

With the exception of income taxes, the factors that affected upgrading performance in the first six months of 2005 compared with the first six months of 2004 were essentially the same as those during the second quarter of 2005 and 2004. The income tax rate was lower in the first six months of 2004 as a result of a cumulative benefit from a rate reduction enacted during the first quarter of 2004.

Infrastructure and Marketing Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)	**2005**	2004	**2005**	2004
Gross margin - pipeline	**$ 22**	$ 23	**$ 47**	$ 42
- other infrastructure and marketing	**39**	34	**116**	77
	61	57	**163**	119
Other expenses	**2**	2	**5**	4
Depreciation and amortization	**6**	5	**11**	10
Income taxes	**20**	16	**52**	34
Earnings	**$ 33**	$ 34	**$ 95**	$ 71
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**488**	520	**499**	515

Second Quarter

Infrastructure and marketing earnings decreased slightly in the second quarter of 2005 compared with the second quarter of 2004 due to:

- Higher income taxes due to higher earnings

Partially offset by:

- Higher marketing margins for crude oil and natural gas

Six Months

The factors that affected infrastructure and marketing earnings in the first six months of 2005 compared with the first six months of 2004 were essentially the same as those during the second quarter of 2005 and 2004. In addition, pipeline margins were higher during the first six months of 2005 compared with 2004.

REFINED PRODUCTS

Refined Products Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2005**	2004	**2005**	2004
Gross margin - fuel sales		**$ 24**	$ 37	**$ 53**	$ 60
- ancillary sales		**9**	7	**16**	14
- asphalt sales		**28**	17	**47**	21
		61	61	**116**	95
Operating and other expenses		**19**	18	**36**	35
Depreciation and amortization		**11**	9	**20**	18
Income taxes		**11**	13	**22**	16
Earnings		**$ 20**	$ 21	**$ 38**	$ 26
Selected operating data:					
Number of fuel outlets				**521**	536
Light oil sales	*(million litres/day)*	**8.8**	8.5	**8.6**	8.4
Light oil sales per outlet	*(thousand litres/day)*	**12.2**	11.2	**12.3**	11.3
Prince George refinery throughput	*(mbbls/day)*	**9.5**	10.4	**9.8**	10.7
Asphalt sales	*(mbbls/day)*	**19.7**	24.2	**18.7**	21.3
Lloydminster refinery throughput	*(mbbls/day)*	**21.6**	26.7	**24.3**	25.7

Second Quarter

Refined products earnings decreased slightly in the second quarter of 2005 compared with the second quarter of 2004 due to:

- Lower marketing margins for gasoline and distillates
- Lower sales volume of asphalt products

Offset by:

- Higher sales volume of motor fuels
- Higher margins for asphalt products
- Lower income taxes

Six Months

With the exception of income taxes, the factors that affected refined products earnings in the first six months of 2005 compared with the first six months of 2004 were essentially the same as those during the second quarter of 2005 and 2004. Income taxes were lower in the first six months of 2004 as a result of a cumulative benefit from a rate reduction enacted during the first quarter of 2004.

CORPORATE

Corporate Summary [1]	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2005**	2004	**2005**	2004
Intersegment eliminations - net	**$ (14)**	$ 13	**$ 9**	$ 30
Administration expenses	**5**	5	**11**	10
Stock-based compensation	**77**	22	**98**	23
Accretion	**1**	1	**1**	1
Other - net	**3**	2	**6**	4
Depreciation and amortization	**5**	8	**11**	18
Interest on debt	**37**	36	**72**	70
Interest capitalized	**(31)**	(18)	**(55)**	(35)
Interest income	**-**	(1)	**(1)**	(1)
Foreign exchange	**20**	12	**27**	24
Income taxes	**(40)**	(31)	**(74)**	(49)
Loss	**$ (63)**	$ (49)	**$ (105)**	$ (95)

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

Foreign Exchange Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2005**	2004	**2005**	2004
(Gain) loss on translation of U.S. dollar denominated long-term debt				
Realized	**$ -**	$ -	**$ (4)**	$ (2)
Unrealized	**22**	25	**35**	48
	22	25	**31**	46
Cross currency swaps	**(4)**	(9)	**(6)**	(14)
Other (gains) losses	**2**	(4)	**2**	(8)
	$ 20	$ 12	**$ 27**	$ 24
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.827**	U.S. $0.763	**U.S. $0.831**	U.S. $0.774
At end of period	**U.S. $0.816**	U.S. $0.746	**U.S. $0.816**	U.S. $0.746

Second Quarter

The corporate loss of $63 million in the second quarter of 2005 compared with $49 million in the second quarter of 2004 was due to:

- Higher stock-based compensation expense during the second quarter of 2005
- Higher foreign exchange costs on U.S. dollar denominated debt

Partially offset by:

- Lower depreciation and amortization
- Higher capitalized interest resulting from the higher White Rose project capital base
- Higher income tax recovery
- Higher inclusion of intersegment profit previously eliminated

Six Months

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

CONSOLIDATED INCOME TAXES

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2005**	2004	**2005**	2004
Income taxes before tax amendments	**$ 195**	$ 113	**$ 386**	$ 228
Bill 27 – Alberta Corporate Tax Amendment Act, 2004	**-**	-	**-**	40
Other items	**19**	13	**19**	13
Income taxes as reported	**$ 176**	$ 100	**$ 367**	$ 175

LIQUIDITY AND CAPITAL RESOURCES

OPERATING ACTIVITIES

In the second quarter of 2005, cash generated from operating activities amounted to $771 million compared with $464 million in the second quarter of 2004. Higher cash flow from operating activities was due to higher earnings.

FINANCING ACTIVITIES

In the second quarter of 2005, cash used in financing activities amounted to $192 million compared with cash generated from financing activities of $129 million in the second quarter of 2004. During the second quarter of 2005, higher debt repayments and dividends net of borrowings and monetization resulted in higher use of cash compared with the second quarter of 2004.

INVESTING ACTIVITIES

In the second quarter of 2005, cash used in investing activities amounted to $585 million compared with $550 million in the second 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 June 30		Six months ended June 30	
(millions of dollars)	**2005**	2004	**2005**	2004
Upstream				
Exploration				
Western Canada	**$ 153**	$ 56	**$ 314**	$ 204
East Coast Canada and Frontier	**14**	8	**18**	14
International	**19**	9	**23**	11
	186	73	**355**	229
Development				
Western Canada	**223**	214	**594**	545
East Coast Canada	**126**	130	**246**	206
International	**1**	4	**3**	4
	350	348	**843**	755
	536	421	**1,198**	984
Midstream				
Upgrader	**30**	18	**47**	26
Infrastructure and Marketing	**7**	4	**13**	7
	37	22	**60**	33
Refined Products	**43**	14	**48**	24
Corporate	**4**	6	**8**	11
Capital expenditures	**620**	463	**1,314**	1,052
Settlement of asset retirement obligations	**(7)**	(5)	**(10)**	(11)
Capital expenditures per Consolidated Statements of Cash Flows	**$ 613**	$ 458	**$ 1,304**	$ 1,041

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

Upstream capital expenditures totaled $1,198 million, 91 percent of total consolidated capital expenditures during the first six months of 2005 compared with $984 million or 94 percent of the total, during the first six months of 2004.

Upstream Capital Expenditures (millions of dollars)	Six months ended June 30 2005
Western Canada Sedimentary Basin sustaining exploitation	**$ 644**
Western Canada foothills and deep basin exploration	**131**
Western Canada oil sands	**133**
Eastern Canada offshore and Northwest Territories	**264**
International exploration and development	**26**
	$ 1,198

The remaining capital expenditures during the first six months of 2005 amounting to $116 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 June 30				Six months ended June 30			
		2005		2004		**2005**		2004	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**10**	**10**	5	5	**35**	**32**	13	12
	Gas	**36**	**21**	16	11	**132**	**93**	124	111
	Dry	**5**	**5**	1	1	**19**	**19**	29	29
		51	**36**	22	17	**186**	**144**	166	152
Development	Oil	**65**	**58**	88	85	**131**	**119**	196	180
	Gas	**47**	**44**	121	113	**278**	**265**	411	388
	Dry	**5**	**5**	10	10	**15**	**15**	37	34
		117	**107**	219	208	**424**	**399**	644	602
Total		**168**	**143**	241	225	**610**	**543**	810	754

(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	Six months ended June 30	Year ended December 31
(millions of dollars)	**2005**	2004
Cash sourced		
Cash flow from operations (1)	**$ 1,644**	$ 2,197
Debt issue	**2,451**	2,200
Asset sales	**57**	36
Proceeds from exercise of stock options	**4**	18
Proceeds from monetization of financial instruments	**30**	8
	4,186	4,459
Cash used		
Capital expenditures	**1,304**	2,349
Corporate acquisitions	**-**	102
Debt repayment	**2,408**	1,959
Special dividend on common shares	**-**	229
Ordinary dividends on common shares	**110**	195
Settlement of asset retirement obligations	**14**	40
Other	**2**	24
	3,838	4,898
Net cash (deficiency)	**348**	(439)
Increase (decrease) in non-cash working capital	**(352)**	443
Increase (decrease) in cash and cash equivalents	**(4)**	4
Cash and cash equivalents - beginning of period	**7**	3
Cash and cash equivalents - end of period	**$ 3**	$ 7
Increase (decrease) in non-cash working capital		
Cash positive working capital change		
Accounts receivable decrease	**$ -**	$ 209
Accounts payable and accrued liabilities increase	**-**	323
	-	532
Cash negative working capital change		
Accounts receivable increase	**20**	-
Inventory increase	**140**	77
Prepaid expense increase	**18**	12
Accounts payable and accrued liabilities decrease	**174**	-
	352	89
Increase (decrease) in non-cash working capital	**$ (352)**	$ 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 June 30, 2005, our working capital deficiency was $445 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	June 30, 2005		
	Outstanding		Available
(millions of dollars)	*(U.S. $)*	*(Cdn $)*	*(Cdn $)*
Short-term bank debt	$ 3	$ 34	$ 147
Long-term bank debt			
Syndicated credit facility	-	100	900
Bilateral credit facilities	-	90	60
Medium-term notes	-	300	
Capital securities	225	276	
U.S. public notes	1,050	1,287	
U.S. senior secured bonds	99	121	
U.S. private placement notes	15	18	
Total short-term and long-term debt	$ 1,392	$ 2,226	$ 1,107
Common shares and retained earnings		$ 6,877	

Financial Ratios	Three months ended June 30		Six months ended June 30	
(millions of dollars, except ratios)	**2005**	2004	**2005**	2004
Cash flow - operating activities	**$ 771**	$ 464	**$ 1,500**	$ 1,165
- financing activities	**$ (192)**	$ 129	**$ (253)**	$ 51
- investing activities	**$ (585)**	$ (550)	**$ (1,251)**	$ (1,144)
Debt to capital employed *(percent)*			**24.5**	27.1
Corporate reinvestment ratio [1] [2]			**1.0**	1.1

[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	July - December 2005	2006-2007	2008-2009	Thereafter
Long-term debt	$ 2,192	$ 36	$ 378	$ 660	$ 1,118
Operating leases	528	34	158	153	183
Firm transportation agreements	772	93	308	188	183
Unconditional purchase obligations	942	283	592	52	15
Lease rentals	330	22	88	88	132
Exploration work agreements	51	27	15	-	9
Engineering and construction commitments	908	516	380	12	-
	$ 5,723	$ 1,011	$ 1,919	$ 1,153	$ 1,640

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. In June 2005, our receivable securitization program was 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. During the first six months of 2004, we paid approximately $9 million for office space in Western Canadian Place.

SIGNIFICANT CUSTOMERS

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

FINANCIAL AND DERIVATIVE INSTRUMENTS

POWER CONSUMPTION

At June 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	July to Dec. 2005	$ 49.25/MWh	$ 0.4
	12.5	July to Dec. 2005	$ 50.50/MWh	0.5
				$ 0.9

FOREIGN CURRENCY RISK MANAGEMENT

At June 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

At June 30, 2005 the cost of a U.S. dollar in Canadian currency was $1.2256.

In the first six months of 2005, the cross currency swaps resulted in an offset to foreign exchange losses on translation of U.S. dollar denominated debt amounting to $6 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains totalling less than $1 million in the first six 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 six months of 2005, we recognized a gain of $8 million.

INTEREST RATE RISK MANAGEMENT

In the first six months of 2005, the interest rate risk management activities resulted in a decrease to interest expense of $9 million.

The cross currency swaps resulted in an addition to interest expense of $5 million in the first six 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 six months of 2005, these swaps resulted in an offset to interest expense amounting to $3 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 six months of 2005, these swaps resulted in an offset to interest expense amounting to $4 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 six 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 $4 million offset to interest expense in the first six 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)		Six months ended June 30 **2005**	Year ended December 31 2004
Share price [(1)]	High	**$ 50.75**	$ 35.65
	Low	**$ 32.30**	$ 22.73
	Close at end of period	**$ 48.73**	$ 34.25
Average daily trading volume		**741**	482
Weighted average number of common shares outstanding			
	Basic	**423,841**	423,362
	Diluted	**423,841**	424,303
Issued and outstanding at end of period [(2)]			
Number of common shares		**423,983**	423,736
Number of stock options		**7,995**	9,964
Number of stock options exercisable		**2,281**	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 June 30, 2005 to July 15, 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 six months ended June 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 second quarter of 2005 compared with the second quarter of 2004 and the first six months of 2005 compared with the first six 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)		Six months ended June 30 **2005**	Year ended December 31 2004
Non-GAAP	Cash flow from operations	**$ 1,644**	$ 2,197
	Settlement of asset retirement obligations	**(14)**	(40)
	Change in non-cash working capital	**(130)**	169
GAAP	Cash flow - operating activities	**$ 1,500**	$ 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)	**June 30 2005**	December 31 2004
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 3**	$ 7
Accounts receivable	**466**	446
Inventories	**414**	274
Prepaid expenses	**69**	52
	952	779
Property, plant and equipment - (full cost accounting)	**20,631**	19,451
Less accumulated depletion, depreciation and amortization	**7,801**	7,258
	12,830	12,193
Goodwill	**160**	160
Other assets	**116**	108
	$ 14,058	$ 13,240
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans	**$ 34**	$ 49
Accounts payable and accrued liabilities	**1,310**	1,498
Long-term debt due within one year *(note 5)*	**53**	56
	1,397	1,603
Long-term debt *(notes 3, 5)*	**2,139**	2,047
Other long-term liabilities *(note 4)*	**662**	632
Future income taxes	**2,983**	2,758
Commitments and contingencies *(note 6)*		
Shareholders' equity		
Common shares *(note 7)*	**3,515**	3,506
Retained earnings	**3,362**	2,694
	6,877	6,200
	$ 14,058	$ 13,240
Common shares outstanding *(millions) (note 7)*	**424.0**	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 June 30 **2005**	2004	Six months ended June 30 **2005**	2004
Sales and operating revenues, net of royalties	**$ 2,493**	$ 2,210	**$ 4,694**	$ 4,231
Costs and expenses				
Cost of sales and operating expenses	**1,474**	1,503	**2,732**	2,854
Selling and administration expenses	**40**	37	**69**	62
Stock-based compensation	**77**	22	**98**	23
Depletion, depreciation and amortization	**304**	288	**602**	571
Interest - net *(notes 3, 5)*	**6**	17	**16**	34
Foreign exchange *(notes 3, 5)*	**20**	12	**27**	24
Other - net	**2**	2	**5**	4
	1,923	1,881	**3,549**	3,572
Earnings before income taxes	**570**	329	**1,145**	659
Income taxes				
Current	**75**	59	**142**	119
Future	**101**	41	**225**	56
	176	100	**367**	175
Net earnings	**$ 394**	$ 229	**$ 778**	$ 484
Earnings per share *(note 8)*				
Basic	**$ 0.93**	$ 0.54	**$ 1.84**	$ 1.14
Diluted	**$ 0.93**	$ 0.54	**$ 1.84**	$ 1.14
Weighted average number of common shares outstanding *(millions) (note 8)*				
Basic	**423.9**	423.4	**423.8**	423.1
Diluted	**423.9**	425.2	**423.8**	424.9

Consolidated Statements of Retained Earnings

(millions of dollars) (unaudited)	Three months ended June 30 **2005**	2004	Six months ended June 30 **2005**	2004
Beginning of period	**$ 3,027**	$ 2,325	**$ 2,694**	$ 2,156
Net earnings	**394**	229	**778**	484
Dividends on common shares	**(59)**	(51)	**(110)**	(93)
Stock-based compensation - retroactive adoption	**-**	-	-	(44)
End of period	**$ 3,362**	$ 2,503	**$ 3,362**	$ 2,503

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 June 30 **2005**	Three months ended June 30 2004	Six months ended June 30 **2005**	Six months ended June 30 2004
Operating activities				
Net earnings	**$ 394**	$ 229	**$ 778**	$ 484
Items not affecting cash				
Accretion *(note 4)*	**9**	8	**17**	14
Depletion, depreciation and amortization	**304**	288	**602**	571
Future income taxes	**101**	41	**225**	56
Foreign exchange	**17**	16	**24**	32
Other	**3**	(1)	**(2)**	-
Settlement of asset retirement obligations	**(9)**	(7)	**(14)**	(13)
Change in non-cash working capital *(note 9)*	**(48)**	(110)	**(130)**	21
Cash flow - operating activities	**771**	464	**1,500**	1,165
Financing activities				
Bank operating loans financing - net	**(48)**	(33)	**(15)**	(71)
Long-term debt issue	**1,029**	1,405	**2,451**	1,461
Long-term debt repayment	**(1,150)**	(1,194)	**(2,393)**	(1,267)
Debt issue costs	**-**	(5)	**-**	(5)
Proceeds from exercise of stock options	**3**	3	**4**	16
Proceeds from monetization of financial instruments	**30**	-	**30**	-
Dividends on common shares	**(59)**	(51)	**(110)**	(93)
Change in non-cash working capital *(note 9)*	**3**	4	**(220)**	10
Cash flow - financing activities	**(192)**	129	**(253)**	51
Available for investing	**579**	593	**1,247**	1,216
Investing activities				
Capital expenditures	**(613)**	(458)	**(1,304)**	(1,041)
Asset sales	**14**	14	**57**	14
Other	**(2)**	(14)	**(2)**	(12)
Change in non-cash working capital *(note 9)*	**16**	(92)	**(2)**	(105)
Cash flow - investing activities	**(585)**	(550)	**(1,251)**	(1,144)
Increase (decrease) in cash and cash equivalents	**(6)**	43	**(4)**	72
Cash and cash equivalents at beginning of period	**9**	32	**7**	3
Cash and cash equivalents at end of period	**$ 3**	$ 75	**$ 3**	$ 75

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

Six months ended June 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 June 30 [1]												
Sales and operating revenues, net of royalties	**$ 976**	$ 800	**$ 393**	$ 213	**$1,566**	$1,669	**$ 560**	$ 457	**$(1,002)**	$ (929)	**$ 2,493**	$ 2,210
Costs and expenses												
Operating, cost of sales, selling and general	**249**	240	**249**	182	**1,507**	1,614	**518**	414	**(930)**	(886)	**1,593**	1,564
Depletion, depreciation and amortization	**278**	262	**4**	4	**6**	5	**11**	9	**5**	8	**304**	288
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**6**	17	**6**	17
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**20**	12	**20**	12
	527	502	**253**	186	**1,513**	1,619	**529**	423	**(899)**	(849)	**1,923**	1,881
Earnings (loss) before income taxes	**449**	298	**140**	27	**53**	50	**31**	34	**(103)**	(80)	**570**	329
Current income taxes	**69**	29	**(2)**	-	**(4)**	14	**(1)**	5	**13**	11	**75**	59
Future income taxes	**73**	65	**45**	8	**24**	2	**12**	8	**(53)**	(42)	**101**	41
Net earnings (loss)	**$ 307**	$ 204	**$ 97**	$ 19	**$ 33**	$ 34	**$ 20**	$ 21	**$ (63)**	$ (49)	**$ 394**	$ 229
Capital expenditures - Three months ended June 30	**$ 536**	$ 421	**$ 30**	$ 18	**$ 7**	$ 4	**$ 43**	$ 14	**$ 4**	$ 6	**$ 620**	$ 463
Six months ended June 30 [1]												
Sales and operating revenues, net of royalties	**$ 1,864**	$ 1,581	**$ 746**	$ 459	**$2,952**	$3,107	**$ 997**	$ 817	**$(1,865)**	$(1,733)	**$ 4,694**	$ 4,231
Costs and expenses												
Operating, cost of sales, selling and general	**489**	465	**444**	394	**2,794**	2,992	**917**	757	**(1,740)**	(1,665)	**2,904**	2,943
Depletion, depreciation and amortization	**551**	516	**9**	9	**11**	10	**20**	18	**11**	18	**602**	571
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**16**	34	**16**	34
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**27**	24	**27**	24
	1,040	981	**453**	403	**2,805**	3,002	**937**	775	**(1,686)**	(1,589)	**3,549**	3,572
Earnings (loss) before income taxes	**824**	600	**293**	56	**147**	105	**60**	42	**(179)**	(144)	**1,145**	659
Current income taxes	**122**	63	**9**	-	**(11)**	26	**(2)**	7	**24**	23	**142**	119
Future income taxes	**156**	97	**80**	14	**63**	8	**24**	9	**(98)**	(72)	**225**	56
Net earnings (loss)	**$ 546**	$ 440	**$ 204**	$ 42	**$ 95**	$ 71	**$ 38**	$ 26	**$ (105)**	$ (95)	**$ 778**	$ 484
Capital employed - As at June 30	**$ 7,878**	$ 7,056	**$ 490**	$ 484	**$ 570**	$ 415	**$ 399**	$ 356	**$ (234)**	$ (77)	**$ 9,103**	$ 8,234
Capital expenditures - Six months ended June 30	**$ 1,198**	$ 984	**$ 47**	$ 26	**$ 13**	$ 7	**$ 48**	$ 24	**$ 8**	$ 11	**$ 1,314**	$ 1,052
Total assets - As at June 30	**$ 11,575**	$ 10,305	**$ 751**	$ 688	**$ 871**	$ 737	**$ 727**	$ 617	**$ 134**	$ 195	**$ 14,058**	$ 12,542

[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:

	Six months ended June 30	
	2005	2004
Asset retirement obligations at beginning of period	**$ 509**	$ 432
Liabilities incurred	**8**	11
Liabilities disposed	**(7)**	-
Liabilities settled	**(14)**	(13)
Accretion	**17**	14
Asset retirement obligations at end of period	**$ 513**	$ 444

At June 30, 2005, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $2.9 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	June 30 2005	Dec. 31 2004	June 30 2005	Dec. 31 2004
		Cdn $ Amount		*U.S. $ Amount*	
Long-term debt					
Syndicated credit facility	2008	**$ 100**	$ 70	**$ -**	$ -
Bilateral credit facilities	2006-8	**90**	40	**-**	-
7.125% notes	2006	**184**	181	**150**	150
8.90% capital securities	2008	**276**	271	**225**	225
6.25% notes	2012	**490**	481	**400**	400
7.55% debentures	2016	**245**	241	**200**	200
6.15% notes	2019	**368**	361	**300**	300
Private placement notes	2005	**18**	18	**15**	15
8.45% senior secured bonds	2005-12	**121**	140	**99**	117
Medium-term notes	2007-9	**300**	300	**-**	-
Total long-term debt		**2,192**	2,103	**$ 1,389**	$ 1,407
Amount due within one year		**(53)**	(56)		
		$ 2,139	$ 2,047		

Interest - net consisted of:

	Three months ended June 30 2005	Three months ended June 30 2004	Six months ended June 30 2005	Six months ended June 30 2004
Long-term debt	**$ 36**	$ 35	**$ 70**	$ 68
Short-term debt	**1**	1	**2**	2
	37	36	**72**	70
Amount capitalized	**(31)**	(18)	**(55)**	(35)
	6	18	**17**	35
Interest income	**-**	(1)	**(1)**	(1)
	$ 6	$ 17	**$ 16**	$ 34

Foreign exchange consisted of:

	Three months ended June 30 2005	Three months ended June 30 2004	Six months ended June 30 2005	Six months ended June 30 2004
Loss on translation of U.S. dollar denominated long-term debt	**$ 22**	$ 25	**$ 31**	$ 46
Cross currency swaps	**(4)**	(9)	**(6)**	(14)
Other (gains) losses	**2**	(4)	**2**	(8)
	$ 20	$ 12	**$ 27**	$ 24

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 - Six months ended June 30, 2004	As Reported	Change	As Restated
Interest - net	$ 20	$ 14	$ 34
Foreign exchange	13	11	24
Future income taxes	63	(7)	56
Net earnings	502	(18)	484

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.

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:

	Six months ended June 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	246,341	9	1,399,967	22
Balance at June 30	**423,982,755**	**$ 3,515**	423,575,709	$ 3,502

Stock Options

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

	Six months ended June 30 2005 Number of Options *(thousands)*	2005 Weighted Average Exercise Prices	2004 Number of Options *(thousands)*	2004 Weighted Average Exercise Prices
Outstanding, beginning of period	9,964	$ 22.61	4,597	$ 13.88
Granted	175	$ 35.29	7,988	$ 24.90
Exercised for common shares	(217)	$ 16.27	(1,189)	$ 13.11
Surrendered for cash	(1,646)	$ 18.10	(167)	$ 13.21
Forfeited	(281)	$ 24.46	(59)	$ 20.46
Outstanding, June 30	**7,995**	**$ 23.92**	11,170	$ 21.82
Options exercisable at June 30	**2,281**	**$ 21.98**	2,497	$ 13.10

	June 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
$12.31 - $14.99	485	$ 13.27	1	414	$ 13.05
$15.00 - $23.99	361	$ 18.74	3	111	$ 17.16
$24.00 - $24.99	6,692	$ 24.38	4	1,748	$ 24.38
$25.00 - $36.10	457	$ 32.58	4	8	$ 27.21
	7,995	**$ 23.92**	**4**	**2,281**	**$ 21.98**

Note 8 Earnings per Common Share

	Three months ended June 30 **2005**	Three months ended June 30 2004	Six months ended June 30 **2005**	Six months ended June 30 2004
Net earnings and net earnings available to common shareholders	**$ 394**	$ 229	**$ 778**	$ 484
Weighted average number of common shares outstanding Basic *(millions)*	**423.9**	423.4	**423.8**	423.1
Effect of dilutive stock options and warrants	**-**	1.8	**-**	1.8
Weighted average number of common shares outstanding Diluted *(millions)*	**423.9**	425.2	**423.8**	424.9
Earnings per share				
Basic	**$ 0.93**	$ 0.54	**$ 1.84**	$ 1.14
Diluted	**$ 0.93**	$ 0.54	**$ 1.84**	$ 1.14

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

	Three months ended June 30		Six months ended June 30	
	2005	2004	**2005**	2004
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 25**	$ 74	**$ (20)**	$ 49
Inventories	**(86)**	(54)	**(140)**	(72)
Prepaid expenses	**(7)**	(22)	**(18)**	(16)
Accounts payable and accrued liabilities	**39**	(196)	**(174)**	(35)
Change in non-cash working capital	**(29)**	(198)	**(352)**	(74)
Relating to:				
Financing activities	**3**	4	**(220)**	10
Investing activities	**16**	(92)	**(2)**	(105)
Operating activities	**$ (48)**	$ (110)	**$ (130)**	$ 21
b) Other cash flow information:				
Cash taxes paid	**$ 76**	$ 101	**$ 159**	$ 152
Cash interest paid	**$ 43**	$ 43	**$ 73**	$ 73

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended June 30		Six months ended June 30	
	2005	2004	**2005**	2004
Employer current service cost	**$ 1**	$ 5	**$ 2**	$ 8
Interest cost	**3**	2	**5**	4
Expected return on plan assets	**(2)**	(2)	**(4)**	(4)
Amortization of net actuarial losses	**-**	-	**1**	1
	$ 2	$ 5	**$ 4**	$ 9

Note 11 Financial Instruments and Risk Management

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

	June 30 2005	Dec. 31 2004
Commodity price risk management		
Natural gas	**$ (7)**	$ (9)
Power consumption	**1**	(1)
Interest rate risk management		
Interest rate swaps	**33**	52
Foreign currency risk management		
Foreign exchange contracts	**(33)**	(30)

Commodity Price Risk Management

- Natural Gas Production

At June 30, 2005, the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for July to December 2005 at an average price of U.S. $1.92 per mcf. During the first six months of 2005, the impact was a loss of $5 million.

- Power Consumption

At June 30, 2005, the Company had hedged power consumption of 99,360 MWh from July to December 2005 at an average fixed price of $49.94 per MWh. The impact of the hedge program during the first six months of 2005 was a loss of less than $1 million.

- Natural Gas Contracts

At June 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	19,204	$ 12
Physical sale contracts	(19,204)	$ (10)

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 six months of 2005, the Company realized a gain of $9 million from interest rate risk management activities.

Foreign Currency Risk Management

During the first six months of 2005, the Company realized a $7 million gain from all foreign currency risk management activities.

During the first six 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 June 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, July 20, 2005 at 4:15 p.m. Eastern time to discuss Husky's second quarter results which will be released after market close on July 19, 2005. To participate, please dial 1-800-404-8949 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 21246538. The PostView will be available until Saturday, August 20, 2005.

Media are invited to participate in the call on a listen-only basis by dialing 1-800-291-5032 beginning at 4:05 p.m. Eastern time.

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