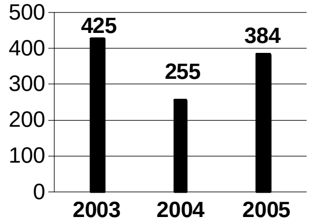
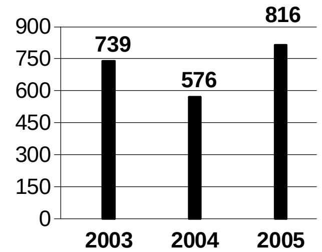
HUSKY ENERGY REPORTS 2005 FIRST QUARTER RESULTS

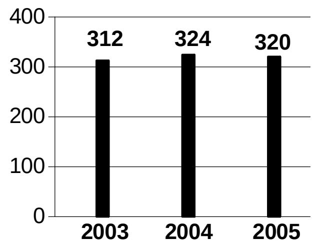
First Quarter
Net Earnings
($ millions)



First Quarter
Cash Flow from Operations
($ millions)



First Quarter
Total Production
(mboe/day)



Calgary, Alberta – Husky Energy Inc. reported net earnings of $384 million or $0.91 per share (diluted) in the first quarter of 2005, compared with $255 million or $0.60 per share (diluted) in the same quarter of 2004, an increase of 51 percent. Cash flow from operations in the first quarter was $816 million or $1.93 per share (diluted), compared with $576 million or $1.36 per share (diluted) in the same quarter of 2004. Sales and operating revenues, net of royalties, were $2.2 billion in the first quarter of 2005, compared with $2.0 billion in the first quarter of 2004. The strong financial results for the quarter were mainly due to strong commodity prices.

"We are pleased with Husky's solid first quarter results, as they demonstrate the continued financial and operational strength of the Company," said Mr. John C.S. Lau, President and Chief Executive Officer, Husky Energy Inc. "Husky's upstream performance was further enhanced by record first quarter earnings in our midstream and refined products business segments."

Total production in the first quarter of 2005 averaged 319,600 barrels of oil equivalent (boe) per day, compared with 324,400 boe per day in the first quarter of 2004. Total crude oil and natural gas liquids production was 206,900 barrels (bbls) per day, compared with 212,100 bbls per day in the first quarter of 2004. Natural gas production was 676.2 million cubic feet (mmcf) per day, compared with 673.6 mmcf per day in the same period last year. The Terra Nova FPSO continued to experience operational issues in the quarter. Production for the Terra Nova oil field averaged net to Husky 13,700 bbls which is 3,900 bbls per day lower than the volume produced in the first quarter of 2004.

Husky's capital expenditures in the first quarter of 2005 were $694 million, compared with $589 million in the first quarter of 2004. Husky's planned capital expenditures for 2005 remain at $2.5 billion, including $460 million for its East Coast projects.

The White Rose offshore project achieved another milestone during this quarter. On March 22, a naming ceremony was held in Busan, South Korea for the first of two shuttle tankers that will transport oil to market from the White Rose oil field off the coast of Newfoundland and Labrador, Canada.

"The White Rose project remains on schedule to achieve first oil in late 2005 or early 2006," said Mr. Lau. "At peak production, the White Rose oil field will produce approximately 92,000 bbls per day and will add approximately 67,500 barrels per day of light oil production to Husky."

Husky's exploration program in the Northwest Territories showed promising results. The first well, Summit Creek B-44, which Husky has 29.5 percent working interest, was tested in two separate zones at a combined rate of nearly 10,000 barrels of oil equivalent per day. The next steps at this location may include a summer seismic program and further exploration and delineation. The second well, Sah Cho L-71, showed non-commercial hydrocarbons in the zone tested and requires further evaluation.

In China, the Wenchang oil field produced 46,000 bbls per day in the first quarter 2005, 18,500 bbls net to Husky. In 2005 we expect to drill three development wells and preparation is underway to drill two exploration wells adjacent to the current producing structures.

At the Tucker thermal project, construction began on the central plant facility, and a drilling program for 30 horizontal well pairs is expected to commence in the second quarter. Conceptual studies have also commenced for the Sunrise thermal project, and regulatory approval is expected by the end of 2005.

Regarding the Midstream and Refined products business segments, significant construction activity continues to take place on the Lloydminster ethanol project, with completion of the 130-million litre per year plant for mid-2006. Husky is targeting to become the largest ethanol producer in Western Canada. At the Prince George refinery, construction on the Clean Fuels project is now approximately 50 percent complete.

Management's Discussion and Analysis

Summary of Quarterly Results

Financial Summary [1]

(millions of dollars, except per share amounts and ratios)		**March 31 2005**	Dec. 31 2004	Sept. 30 2004	June 30 2004	March 31 2004	Dec. 31 2003	Sept. 30 2003	June 30 2003
Sales and operating revenues, net of royalties		**$ 2,201**	$ 2,018	$ 2,191	$ 2,210	$ 2,021	$ 1,800	$ 1,871	$ 1,769
Segmented earnings									
Upstream		**$ 239**	$ 112	$ 161	$ 204	$ 236	$ 169	$ 215	$ 374
Midstream		**169**	77	50	53	60	46	41	49
Refined Products		**18**	(3)	18	21	5	6	22	3
Corporate and eliminations		**(42)**	39	68	(49)	(46)	31	(42)	31
Net earnings		**$ 384**	$ 225	$ 297	$ 229	$ 255	$ 252	$ 236	$ 457
Per share	- Basic	**$ 0.91**	$ 0.53	$ 0.70	$ 0.54	$ 0.60	$ 0.60	$ 0.56	$ 1.09
	- Diluted	**0.91**	0.53	0.70	0.54	0.60	0.59	0.56	1.09
Cash flow from operations		**816**	469	571	581	576	561	597	533
Per share	- Basic	**1.93**	1.11	1.34	1.37	1.36	1.33	1.42	1.27
	- Diluted	**1.93**	1.11	1.34	1.37	1.36	1.32	1.42	1.27
Dividends declared per common share		**0.12**	0.12	0.12	0.12	0.10	0.10	0.10	0.09
Special dividend per common share		**-**	0.54	-	-	-	-	1.00	-
Total assets		**13,690**	13,240	12,901	12,542	12,317	11,949	11,771	11,389
Total long-term debt including current portion		**2,290**	2,103	2,096	2,229	1,993	1,989	2,279	2,300
Return on equity [2]	*(percent)*	**18.3**	17.0	17.7	16.8	21.8	26.4	27.2	25.5
Return on average capital employed [2]	*(percent)*	**13.9**	13.0	13.4	12.7	16.2	18.9	19.0	18.0

[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

		March 31 2005	Dec. 31 2004	Sept. 30 2004	June 30 2004	March 31 2004
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**31.9**	32.9	33.1	32.9	32.9
Medium crude oil		**32.4**	33.7	34.5	35.6	36.1
Heavy crude oil		**110.4**	113.8	108.8	107.4	105.6
		174.7	180.4	176.4	175.9	174.6
East Coast Canada						
Terra Nova - light crude oil		**13.7**	10.1	11.5	15.7	17.6
China						
Wenchang - light crude oil		**18.5**	17.9	20.2	20.6	19.9
		206.9	208.4	208.1	212.2	212.1
Natural gas	*(mmcf/day)*	**676.2**	697.4	700.4	685.4	673.6
Total	*(mboe/day)*	**319.6**	324.6	324.8	326.4	324.4

Crude oil and natural gas production in the first quarter of 2005 was 319.6 mboe/day compared with 324.6 mboe/day in the previous quarter and 324.4 mboe/day in the first quarter of 2004. Production in the first quarter of 2005 compared with the previous quarter was lower primarily as a result of higher natural gas reservoir declines. As a result of new natural gas wells tied-in throughout the first quarter, the average rate for natural gas production reached 695 mmcf/day in March compared with 676 mmcf/day for the quarter. Natural gas tie-ins during the second quarter of 2005 are expected to bring production into our forecast range.

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		Three months ended March 31	Forecast	Three months ended March 31	Year ended December 31
		2005	2005	2004	2004
Crude oil & NGL	*(mbbls/day)*				
Light crude oil & NGL		**64.1**	64 - 71	70.4	66.2
Medium crude oil		**32.4**	32 - 36	36.1	35.0
Heavy crude oil		**110.4**	112 - 120	105.6	108.9
		206.9	208 - 227	212.1	210.1
Natural gas	*(mmcf/day)*	**676.2**	700 - 740	673.6	689.2
Total barrels of oil equivalent	*(mboe/day)*	**319.6**	325 - 350	324.4	325.0

2005 will be a year of continued exploitation of our producing asset base in the Western Canada Sedimentary Basin ("WCSB"), with a particular focus on heavy crude oil and natural gas production. Our properties throughout the WCSB form the foundation of our upstream business. 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 at favourable costs necessary to fund our growth portfolio, subject to variability based on commodity prices. With continued commensurate capital expenditures, the WCSB asset base will generally provide predictable production. Production replacement in the south and east central region of the WCSB is expected to be maintained with small overall declines. In the north and western regions of the basin and in the Lloydminster heavy oil area, production replacement is expected to be greater than 100 percent. In addition, we expect to continue to realize additional value from managing our operating costs in the WCSB through consolidation via strategic acquisitions and divestitures and improvements in production technology and practice.

Our major construction projects with significant long-term potential are currently in various planning stages and will move our production profile to a new level.

At March 31, 2005, we had invested just over $2 billion in projects offshore Canada's East Coast, in the Alberta oil sands and offshore Indonesia, which upon completion, will begin to deliver this potential. These projects are summarized below:

Project		Productive Capacity [1]	Working Interest	Schedule
White Rose	Offshore East Coast	68 mbbls/day	72.5%	Late 2005 - 2006
Tucker	Oil Sands	30 mbbls/day	100%	2006 - 2007
Sunrise	Oil Sands [2]	50 mbbls/day	100%	2009 - 2010

[1] *Husky interest.*

[2] *Sunrise will be developed in phases; ultimate planned rate is 200 mbbls/day.*

In addition to these projects, 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 in the basins off of Newfoundland and Labrador, in the Central Mackenzie Valley area of the Northwest Territories, offshore China and in the Madura Strait in Indonesia.

East Coast

At Marystown, Newfoundland and Labrador, the installation and commissioning of the topsides facilities onboard the *SeaRose* FPSO floating production storage and offloading vessel ("*SeaRose*") is continuing. The first four of 42 topsides systems have been turned over to us as complete. All systems will be tested after full integration. The crewmembers of the *SeaRose* FPSO are currently in training. The production and gas injection flowlines are being constructed in Le Trait, France and are expected to be installed this summer.

At the White Rose field, a horizontal production well and a water injection well were drilled during the first quarter of 2005. These wells bring the total number of development wells drilled to eight. We are also preparing to drill a number of delineation wells in proximity to the White Rose structure.

Tucker

During the first quarter of 2005, Husky completed preparations for the commencement of drilling operations in early April. This included completing construction of two drilling pads, moving in drilling equipment, installing a 100 person camp and completing three additional stratigraphic test wells. A baseline three-dimensional seismic survey was also completed. Facility work continues to progress in accordance with the construction schedule and all long lead-time components have been ordered.

Sunrise

During the first quarter of 2005, Husky prepared responses to supplemental questions from regulators and other stakeholders with regard to the application for project approval, which was submitted to the regulators in August 2004. Discussions with key stakeholders are ongoing. The conceptual design phase for the Sunrise project has commenced.

Exploration Programs

- Western Canada

During the first quarter of 2005 we drilled 135 exploratory wells (108 net) resulting in 96 (72 net) natural gas completions and 25 (22 net) oil completions.

Exploration activity was concentrated in the Bivouac, Ekwan and Titan areas of northeastern British Columbia where 12 horizontal exploration wells were drilled following up on natural gas discoveries made in this region in previous years. Infrastructure capacity in the area will be expanded to handle 40 mmcf/day of natural gas. Our working interest in these areas averages approximately 90 percent.

Near Moose Mountain in the southern Alberta foothills, a previous natural gas discovery was completed and flow tested at restricted rates in excess of 6 mmcf/day. This well will be tied-in during the fourth quarter of 2005 and based on the test data, is expected to produce at a rate of approximately 14 mmcf/day. Our working interest in this well is 43.5 percent. This area continues to be prospective and further exploration is being considered.

- Northwest Territories

During the first quarter of 2005 in the Central Mackenzie Valley we participated in the completion and testing of the Summit Creek B-44 exploratory well that was drilled in the winter of 2004 and the drilling of the Sah Cho L-71 exploratory well, in which we have working interests of 29.4775 percent and 32.5 percent, respectively.

The Summit Creek B-44 well confirmed several productive intervals in a 180 metre hydrocarbon bearing column. Two intervals were perforated and tested at combined rates of approximately 20 mmcf/day of natural gas and in excess of 6 mbbls/day of light oil and condensate.

Preliminary testing of the Sah Cho L-71 well, which was drilled on a separate structure from B-44, did not establish the presence of commercial hydrocarbons and the well was cased and suspended pending further evaluation.

The Summit Creek B-44 discovery represents the first in this area since Norman Wells was discovered in 1920. The working interest owners have accumulated over a million gross acres, covering the majority of the central extent of the play. Based on existing seismic data several additional prospects have been identified and further seismic is currently being contemplated for this summer.

- East Coast

We are planning to drill an exploratory well in the South Whale Basin with the Rowan Gorilla VI jack-up rig. The well will test a structure at the Lewis Hill prospect and will spud toward the end of the second quarter of 2005.

- China

In China we are progressing toward final selection of a shallow water jack-up rig for at least two exploratory wells, with a possible third option well, in the Gulf of Beibu. In addition, we are in the final stages of selecting a deep water rig for an exploratory well on Block 29/26 in the South China Sea. At the Wenchang oil field, preparation is underway to drill two exploratory wells to test anomalies adjacent to the producing structures. These wells will be operated by the China National Offshore Oil Corporation.

- Indonesia

In Indonesia, where we recently increased our interest in the Madura Strait production sharing contract area, work is progressing toward establishing a natural gas contract for the two natural gas fields yet to be developed. In addition, we have commenced seismic studies on the Madura exploration areas.

Midstream

Husky Lloydminster Upgrader

The debottleneck projects are on schedule 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 following a 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 $110 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.

Business Environment

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

- 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. dollars
- refined petroleum products margins
- demand for Husky's pipeline capacity
- demand for refined petroleum products
- government regulations
- cost of capital

Average Benchmark Prices and U.S. Exchange Rate

		Three months ended				
		March 31 2005	Dec. 31 2004	Sept. 30 2004	June 30 2004	March 31 2004
WTI crude oil [1]	*(U.S. $/bbl)*	**$ 49.84**	$ 48.28	$ 43.88	$ 38.32	$ 35.15
Canadian par light crude 0.3% sulphur	*($/bbl)*	**62.02**	58.01	56.61	50.99	46.00
Lloyd @ Lloydminster heavy crude oil	*($/bbl)*	**22.62**	25.31	35.47	28.09	26.12
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**6.27**	7.11	5.76	5.97	5.69
NIT natural gas	*($/GJ)*	**6.34**	6.72	6.32	6.45	6.26
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**19.57**	19.82	12.86	11.82	10.12
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.815**	0.819	0.765	0.736	0.759

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

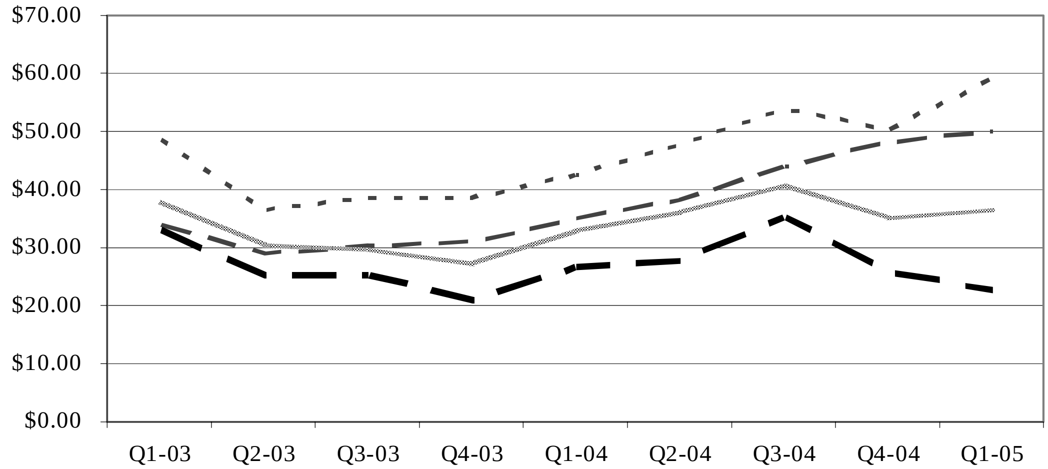
Commodity Price Risk

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)

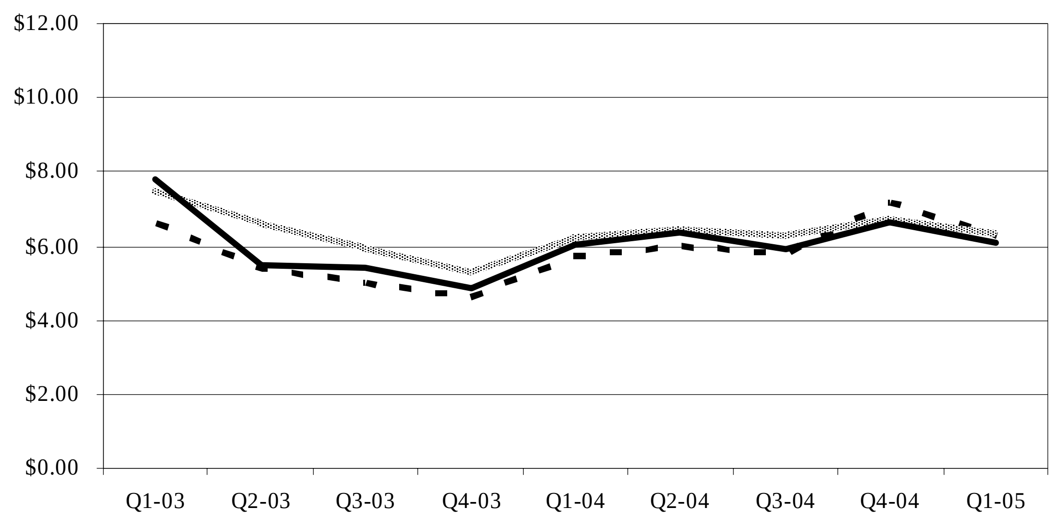


	Q1-03	Q2-03	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04	Q1-05
West Texas Intermediate ("WTI") (U.S. $)	$33.86	$28.91	$30.20	$31.18	$35.15	$38.32	$43.88	$48.28	$49.84
Husky average light crude oil price (C $)	$48.58	$36.45	$38.49	$38.55	$42.50	$47.99	$53.94	$50.29	$58.94
Husky average medium crude oil price (C $)	$37.86	$30.48	$29.68	$27.25	$32.97	$35.98	$40.59	$35.06	$36.50
Husky average heavy crude oil price (C $)	$33.02	$25.13	$25.13	$20.84	$26.38	$27.54	$34.92	$25.81	$22.53

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



	Q1-03	Q2-03	Q3-03	Q4-03	Q1-04	Q2-04	Q3-04	Q4-04	Q1-05
NYMEX natural gas (U.S. $/mmbtu)	$6.60	$5.39	$4.97	$4.58	$5.69	$5.97	$5.76	$7.11	$6.27
NIT natural gas (C $/GJ)	$7.51	$6.63	$5.97	$5.30	$6.26	$6.45	$6.32	$6.72	$6.34
Husky average natural gas price (C $/mcf)	$7.80	$5.50	$5.40	$4.87	$6.05	$6.38	$5.92	$6.64	$6.07

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 produced 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 the 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. dollars. 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 Husky's expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities 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 March 31, 2005, 73 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 first quarter of 2005 was $1.2096. 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. 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 is indicative of the relative effect of changes in certain key variables on pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the first 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*	80	0.19	55	0.13
NYMEX benchmark natural gas price [1]	*U.S. $0.20/mmbtu*	35	0.08	23	0.05
Light/heavy crude oil differential [2]	*Cdn $1.00/bbl*	(28)	(0.07)	(18)	(0.04)
Light oil margins	*Cdn $0.005/litre*	15	0.04	10	0.02
Asphalt margins	*Cdn $1.00/bbl*	6	0.02	4	0.01
Exchange rate (U.S. $ / Cdn $) [3]	*U.S. $0.01*	(53)	(0.12)	(37)	(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 $13 million in net earnings based on March 31, 2005 U.S. dollar denominated debt levels.*

(4) *Based on March 31, 2005 common shares outstanding of 423.9 million.*

Results of Operations

Upstream

Upstream Earnings Summary

(millions of dollars)	Three months ended March 31 2005	2004
Gross revenues	**$ 1,040**	$ 1,013
Royalties	**152**	158
Hedging	**-**	74
Net revenues	**888**	781
Operating and administration expenses	**240**	225
Depletion, depreciation and amortization	**273**	254
Income taxes	**136**	66
Earnings	**$ 239**	$ 236

Net Revenue Variance Analysis

(millions of dollars)	Crude oil & NGL	Natural gas	Other	Total
Three months ended March 31, 2004	$ 469	$ 297	$ 15	$ 781
Price changes	61	(1)	-	60
Volume changes	(31)	(3)	-	(34)
Royalties	(5)	11	-	6
Hedging	78	(4)	-	74
Processing and sulphur	-	-	1	1
Three months ended March 31, 2005	**$ 572**	**$ 300**	**$ 16**	**$ 888**

Upstream earnings were $3 million higher in the first quarter of 2005 than in the first quarter of 2004 as a result of the following factors:

- higher light and medium crude oil prices
- hedging diverted $74 million in the first quarter of 2004; first quarter of 2005 commodity prices were not hedged

partially offset by:

- lower sales volume of light and medium crude oil
- lower heavy crude oil prices
- higher unit operating costs
- higher unit depletion, depreciation and amortization
- higher income taxes primarily due to a tax benefit recorded in the first quarter of 2004 and also due to higher earnings in the first quarter of 2005

Unit Operating Costs

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

Unit Depletion, Depreciation and Amortization

Unit depletion, depreciation and amortization expense increased 10 percent in the first 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. This was partially offset in the first quarter of 2005 by higher proved reserves in the Canadian cost centre.

Average Sales Prices		Three months ended March 31	
		2005	2004
Crude Oil	*($/bbl)*		
Light crude oil & NGL		**$ 56.43**	$ 41.84
Medium crude oil		**36.50**	32.97
Heavy crude oil		**22.53**	26.38
Total average		**35.22**	32.42
Natural Gas	*($/mcf)*		
Average		**6.07**	6.05

Effective Royalty Rates (1)	Three months ended March 31	
Percentage of upstream sales revenues	**2005**	2004
Crude oil & NGL	**12%**	12%
Natural gas	**19%**	22%
Total	**15%**	16%

(1) *Before commodity hedging.*

Upstream Revenue Mix (1)	Three months ended March 31	
Percentage of upstream sales revenues, after royalties	**2005**	2004
Light crude oil & NGL	**32%**	27%
Medium crude oil	**10%**	11%
Heavy crude oil	**23%**	27%
Natural gas	**35%**	35%
	100%	100%

(1) *Before commodity hedging.*

Operating Netbacks

Western Canada

Light Crude Oil Netbacks (1)

Per boe	Three months ended March 31 **2005**	2004
Sales revenues	**$ 50.83**	$ 40.55
Royalties	**5.01**	7.19
Operating costs	**9.86**	8.87
Netback	**$ 35.96**	$ 24.49

Medium Crude Oil Netbacks (1)

Per boe	Three months ended March 31 **2005**	2004
Sales revenues	**$ 36.42**	$ 33.05
Royalties	**6.41**	5.62
Operating costs	**10.53**	9.63
Netback	**$ 19.48**	$ 17.80

Heavy Crude Oil Netbacks (1)

Per boe	Three months ended March 31 **2005**	2004
Sales revenues	**$ 22.70**	$ 26.52
Royalties	**2.19**	2.79
Operating costs	**9.24**	9.38
Netback	**$ 11.27**	$ 14.35

Natural Gas Netbacks (2)

Per mcfge	Three months ended March 31 **2005**	2004
Sales revenues	**$ 6.17**	$ 6.00
Royalties	**1.39**	1.34
Operating costs	**0.95**	0.79
Netback	**$ 3.83**	$ 3.87

Total Western Canada Upstream Netbacks (1)

Per boe	Three months ended March 31 **2005**	2004
Sales revenues	**$ 32.95**	$ 32.65
Royalties	**5.34**	5.67
Operating costs	**8.11**	7.62
Netback	**$ 19.50**	$ 19.36

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

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

Terra Nova Crude Oil Netbacks

Per boe	Three months ended March 31 **2005**	2004
Sales revenues	**$ 60.73**	$ 43.29
Royalties	**3.02**	1.08
Operating costs	**3.93**	2.79
Netback	**$ 53.78**	$ 39.42

Wenchang Crude Oil Netbacks

Per boe	Three months ended March 31 **2005**	2004
Sales revenues	**$ 58.94**	$ 41.18
Royalties	**5.43**	4.19
Operating costs	**2.38**	2.18
Netback	**$ 51.13**	$ 34.81

Total Upstream Segment Netbacks (1)

Per boe	Three months ended March 31 **2005**	2004
Sales revenues	**$ 35.65**	$ 33.76
Royalties	**5.25**	5.33
Operating costs	**7.60**	7.03
Netback	**$ 22.80**	$ 21.40

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

Midstream

Upgrading Earnings Summary

(millions of dollars, except where indicated)		Three months ended March 31 **2005**	2004
Gross margin		**$ 207**	$ 85
Operating costs		**50**	52
Other recoveries		**(1)**	(1)
Depreciation and amortization		**5**	5
Income taxes		**46**	6
Earnings		**$ 107**	$ 23
Selected operating data:			
Upgrader throughput (1)	*(mbbls/day)*	**72.1**	70.4
Synthetic crude oil sales	*(mbbls/day)*	**63.9**	58.2
Upgrading differential	*($/bbl)*	**$ 32.09**	$ 13.80
Unit margin	*($/bbl)*	**$ 35.91**	$ 15.95
Unit operating cost (2)	*($/bbl)*	**$ 7.70**	$ 8.16

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

(2) *Based on throughput.*

Upgrading Earnings Variance Analysis

(millions of dollars)	
Three months ended March 31, 2004	$ 23
Volume	7
Margin	115
Operating costs - energy related	1
Operating costs - non-energy related	1
Income taxes	(40)
Three months ended March 31, 2005	**$ 107**

Upgrading earnings increased in the first quarter of 2005 by $84 million compared with the first quarter of 2004 due to the following factors:

- wider upgrading differential
- higher sales volume of synthetic crude oil
- lower unit operating costs

partially offset by:

- higher income taxes due to higher earnings

Infrastructure and Marketing Earnings Summary

(millions of dollars, except where indicated)	Three months ended March 31 **2005**	2004
Gross margin - pipeline	**$ 25**	$ 19
- other infrastructure and marketing	**77**	43
	102	62
Other expenses	**3**	2
Depreciation and amortization	**5**	5
Income taxes	**32**	18
Earnings	**$ 62**	$ 37
Selected operating data:		
Aggregate pipeline throughput *(mbbls/day)*	**510**	510

Infrastructure and marketing earnings increased by $25 million in the first quarter of 2005 compared with the first quarter of 2004 due the following factors:

- higher marketing margins for crude oil and natural gas
- higher pipeline margins

partially offset by:

- higher income taxes due to higher earnings

Refined Products

Refined Products Earnings Summary			Three months ended March 31	
(millions of dollars, except where indicated)			**2005**	2004
Gross margin	- fuel sales		**$ 29**	$ 23
	- ancillary sales		**7**	7
	- asphalt sales		**19**	4
			55	34
Operating and other expenses			**17**	17
Depreciation and amortization			**9**	9
Income taxes			**11**	3
Earnings			**$ 18**	$ 5
Selected operating data:				
Number of fuel outlets			**523**	543
Light oil sales		*(million litres/day)*	**8.3**	8.4
Light oil sales per outlet		*(thousand litres/day)*	**12.4**	11.4
Prince George refinery throughput		*(mbbls/day)*	**10.0**	10.9
Asphalt sales		*(mbbls/day)*	**17.7**	18.4
Lloydminster refinery throughput		*(mbbls/day)*	**27.1**	24.8

Refined products earnings increased by $13 million in the first quarter of 2005 compared with the first quarter of 2004 due to the following factors:

- higher marketing margins for gasoline, distillates and asphalt products

partially offset by:

- lower sales volume of motor fuels and asphalt products
- higher income taxes due to higher earnings

Corporate

Corporate Summary [1]	Three months ended March 31	
(millions of dollars)	**2005**	2004
Intersegment eliminations - net	**$ 23**	$ 17
Administration expenses	**6**	5
Stock-based compensation	**21**	1
Other - net	**3**	2
Depreciation and amortization	**6**	10
Interest on debt	**35**	34
Interest capitalized	**(24)**	(17)
Interest income	**(1)**	-
Foreign exchange	**7**	12
Income taxes	**(34)**	(18)
Loss	**$ (42)**	$ (46)

[1] *2004 amounts as restated. Refer to Note 3 to the Consolidated Financial Statements.*

Foreign Exchange Summary

(millions of dollars)	Three months ended March 31 **2005**	2004
(Gain) loss on translation of U.S. dollar denominated long-term debt		
Realized	**$ (4)**	$ (2)
Unrealized	**13**	23
	9	21
Cross currency swaps	**(2)**	(5)
Other gains	**-**	(4)
	$ 7	$ 12
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $0.831**	U.S. $0.774
At end of period	**U.S. $0.827**	U.S. $0.763

The corporate loss of $42 million in the first quarter of 2005 compared with $46 million in the first quarter of 2004 was due to the following factors:

- stock-based compensation first marked to market in June 2004 under a tandem plan; stock-based compensation recorded during the first quarter of 2005 was $21 million
- higher intersegment profit eliminated

partially offset by:

- lower depreciation and amortization
- higher capitalized interest resulting from the higher White Rose project capital base
- higher income tax recovery

Consolidated Income Taxes

On March 24, 2005, Bill C-43, an act to implement certain provisions of the federal budget tabled on February 23, 2005, received first reading in the House of Commons. However, Bill C-43 was not considered substantively enacted and as a result, no tax rate adjustments were recorded in our financial statements in the first quarter of 2005.

On March 31, 2004, Bill 27 – Alberta Corporate Tax Amendment Act, 2004 was substantively enacted and a non-recurring benefit of $40 million was recorded in the first quarter of 2004.

(millions of dollars)	Three months ended March 31 **2005**	2004
Income taxes before tax amendments	**$ 191**	$ 115
Bill 27 – Alberta Corporate Tax Amendment Act, 2004	**-**	40
Income taxes as reported	**$ 191**	$ 75

Liquidity and Capital Resources

Operating Activities

In the first quarter of 2005, cash generated from operating activities amounted to $729 million compared with $701 million in the first quarter of 2004. Higher cash flow from earnings was almost entirely offset by increased non-cash working capital associated with operating activities, which was due primarily to reduced accounts payable and accrued liabilities.

Financing Activities

In the first quarter of 2005, cash used in financing activities amounted to $61 million compared with $78 million in the first quarter of 2004. During the first quarter of 2005, cash from net borrowings was offset by an increase in non-cash working capital associated with financing activities.

Investing Activities

In the first quarter of 2005, cash used in investing activities amounted to $666 million compared with $594 million in the first 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 March 31	
(millions of dollars)	**2005**	2004
Upstream		
Exploration		
Western Canada	**$ 161**	$ 148
East Coast Canada and Frontier	**4**	6
International	**4**	2
	169	156
Development		
Western Canada	**371**	331
East Coast Canada	**120**	76
International	**2**	-
	493	407
	662	563
Midstream		
Upgrader	**17**	8
Infrastructure and Marketing	**6**	3
	23	11
Refined Products	**5**	10
Corporate	**4**	5
Capital expenditures	**694**	589
Settlement of asset retirement obligations	**(3)**	(6)
Capital expenditures per Consolidated Statements of Cash Flows	**$ 691**	$ 583

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

Upstream capital expenditures totaled $662 million, 95 percent of total consolidated capital expenditures during the first quarter of 2005 compared with $563 million or 96 percent of the total, during the first quarter of 2004.

Upstream Capital Expenditures (millions of dollars)	Three months ended March 31 2005
Western Canada Sedimentary Basin sustaining exploitation	**$ 397**
Western Canada foothills and Deep Basin exploration	**87**
Western Canada Oil Sands	**48**
Eastern Canada Offshore and Northwest Territories	**124**
International exploration and development	**6**
	$ 662

The remaining capital expenditures during the first quarter of 2005 amounting to $32 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 March 31			
		2005		2004	
		Gross	**Net**	Gross	Net
Exploration	Oil	**25**	**22**	8	7
	Gas	**96**	**72**	108	100
	Dry	**14**	**14**	28	28
		135	**108**	144	135
Development	Oil	**66**	**61**	108	95
	Gas	**231**	**221**	290	275
	Dry	**10**	**10**	27	24
		307	**292**	425	394
Total		**442**	**400**	569	529

(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	Three months ended March 31	Year ended December 31
(millions of dollars)	**2005**	2004
Cash sourced		
Cash flow from operations [1]	**$ 816**	$ 2,197
Debt issue	**1,455**	2,200
Asset sales	**43**	36
Proceeds from exercise of stock options	**1**	18
Proceeds from monetization of financial instruments	**-**	8
	2,315	4,459
Cash used		
Capital expenditures	**691**	2,349
Corporate acquisitions	**-**	102
Debt repayment	**1,243**	1,959
Special dividend on common shares	**-**	229
Ordinary dividends on common shares	**51**	195
Settlement of asset retirement obligations	**5**	40
Other	**-**	24
	1,990	4,898
Net cash (deficiency)	**325**	(439)
Increase (decrease) in non-cash working capital	**(323)**	443
Increase in cash and cash equivalents	**2**	4
Cash and cash equivalents - beginning of period	**7**	3
Cash and cash equivalents - end of period	**$ 9**	$ 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	**45**	-
Inventory increase	**54**	77
Prepaid expense increase	**11**	12
Accounts payable and accrued liabilities decrease	**213**	-
	323	89
Increase (decrease) in non-cash working capital	**$ (323)**	$ 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 March 31, 2005, our working capital deficiency was $507 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)	March 31, 2005 Outstanding (U.S. $)	Outstanding (Cdn $)	Available (Cdn $)
Short-term bank debt	$ 1	$ 82	$ 94
Long-term bank debt			
Syndicated credit facility	-	260	740
Bilateral credit facilities	-	50	100
Medium-term notes	-	300	
Capital securities	225	272	
U.S. public notes	1,050	1,270	
U.S. senior secured bonds	99	120	
U.S. private placement notes	15	18	
Total short-term and long-term debt	$ 1,390	$ 2,372	$ 934
Common shares and retained earnings		$ 6,536	

Financial Ratios

(millions of dollars, except ratios)	Three months ended March 31 **2005**	2004
Cash flow - operating activities	**$ 729**	$ 701
- financing activities	**$ (61)**	$ (78)
- investing activities	**$ (666)**	$ (594)
Debt to capital employed *(percent)*	**26.6**	25.8
Corporate reinvestment ratio [(1)] [(2)]	**1.0**	1.0

[(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	April - December 2005	2006-2007	2008-2009	Thereafter
Long-term debt	$ 2,290	$ 35	$ 366	$ 786	$ 1,103
Operating leases	530	44	152	151	183
Firm transportation agreements	1,008	160	375	262	211
Unconditional purchase obligations	1,333	445	684	87	117
Lease rentals	331	33	88	88	122
Exploration work agreements	51	27	15	-	9
Engineering and construction commitments	956	532	412	12	-
	$ 6,499	$ 1,276	$ 2,092	$ 1,386	$ 1,745

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. At March 31, 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 substantially 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 quarter of 2004, we paid approximately $5 million for office space in Western Canadian Place.

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

Financial and Derivative Instruments

Power Consumption

At March 31, 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	Apr. to Dec. 2005	$49.25/MWh	$ 0.5
	12.5	Apr. to Dec. 2005	$50.50/MWh	0.5
	15.0	Apr. to Jun. 2005	$48.00/MWh	0.1
				$ 1.1

Foreign Currency Risk Management

At March 31, 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 March 31, 2005 the cost of a U.S. dollar in Canadian currency was $1.2096.

In the first quarter of 2005, the cross currency swaps resulted in an offset to foreign exchange losses on translation of U.S. dollar denominated debt amounting to $2 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains totalling approximately $1 million in the first quarter of 2005.

Interest Rate Risk Management

In the first quarter of 2005, the interest rate risk management activities resulted in a decrease to interest expense of $5 million.

The cross currency swaps resulted in an addition to interest expense of $3 million in the first quarter 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 quarter of 2005, these swaps resulted in an offset to interest expense amounting to $1 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 quarter of 2005, these swaps resulted in an offset to interest expense amounting to $2 million.

Husky has interest rate swaps on U.S. $300 million of long-term debt effective June 18, 2004 whereby 6.15 percent was swapped for an average U.S. LIBOR + 63 bps until June 15, 2019. During the first quarter of 2005, these swaps resulted in an offset to interest expense amounting to $3 million.

The amortization of previous interest rate swap terminations resulted in an additional $2 million offset to interest expense in the first quarter of 2005.

During the first quarter of 2005, we recognized a gain of $8 million from our long-dated forwards, which were unwound in 2004.

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)		Three months ended March 31 **2005**	Year ended December 31 2004
Share price [1]	High	**$ 40.49**	$ 35.65
	Low	**$ 32.30**	$ 22.73
	Close at end of period	**$ 36.33**	$ 34.25
Average daily trading volume		**748**	482
Weighted average number of common shares outstanding			
	Basic	**423,791**	423,362
	Diluted	**423,791**	424,303
Issued and outstanding at end of period [2]			
Number of common shares		**423,850**	423,736
Number of stock options		**9,533**	9,964
Number of stock options exercisable		**1,127**	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 March 31, 2005 to April 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 three months ended March 31, 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 first quarter of 2005 compared with the first quarter 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.

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.

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)		Three months ended March 31 **2005**	Year ended December 31 2004
Non-GAAP	Cash flow from operations	**$ 816**	$ 2,197
	Settlement of asset retirement obligations	**(5)**	(40)
	Change in non-cash working capital	**(82)**	169
GAAP	Cash flow - operating activities	**$ 729**	$ 2,326

Forward-looking Statements

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

This document contains certain forward-looking statements relating, but not limited, to Husky's operations, anticipated financial performance, business prospects and strategies and which are based on our current 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, schedules and production volumes, 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. 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
- 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 accuracy of our oil and gas reserve estimates, estimated production levels and our success at exploration and development drilling and related activities
- 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
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- actions by governmental authorities, including changes in environmental and other regulations
- 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)	**March 31 2005**	December 31 2004
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 9**	$ 7
Accounts receivable	**491**	446
Inventories	**328**	274
Prepaid expenses	**62**	52
	890	779
Property, plant and equipment - (full cost accounting)	**20,052**	19,451
Less accumulated depletion, depreciation and amortization	**7,524**	7,258
	12,528	12,193
Goodwill	**160**	160
Other assets	**112**	108
	$ 13,690	$ 13,240
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans	**$ 82**	$ 49
Accounts payable and accrued liabilities	**1,263**	1,498
Long-term debt due within one year *(note 5)*	**52**	56
	1,397	1,603
Long-term debt *(notes 3, 5)*	**2,238**	2,047
Other long-term liabilities *(note 4)*	**637**	632
Future income taxes	**2,882**	2,758
Commitments and contingencies *(note 6)*		
Shareholders' equity		
Common shares *(note 7)*	**3,509**	3,506
Retained earnings	**3,027**	2,694
	6,536	6,200
	$ 13,690	$ 13,240
Common shares outstanding *(millions) (note 7)*	**423.9**	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 March 31 **2005**	2004
Sales and operating revenues, net of royalties	**$ 2,201**	$ 2,021
Costs and expenses		
Cost of sales and operating expenses	**1,258**	1,351
Selling and administration expenses	**29**	25
Stock-based compensation	**21**	1
Depletion, depreciation and amortization	**298**	283
Interest - net *(notes 3, 5)*	**10**	17
Foreign exchange *(notes 3, 5)*	**7**	12
Other - net	**3**	2
	1,626	1,691
Earnings before income taxes	**575**	330
Income taxes		
Current	**67**	60
Future	**124**	15
	191	75
Net earnings	**$ 384**	$ 255
Earnings per share *(note 8)*		
Basic	**$ 0.91**	$ 0.60
Diluted	**$ 0.91**	$ 0.60
Weighted average number of common shares outstanding *(millions) (note 8)*		
Basic	**423.8**	422.7
Diluted	**423.8**	424.7

Consolidated Statements of Retained Earnings

(millions of dollars) (unaudited)	Three months ended March 31 **2005**	2004
Beginning of period	**$ 2,694**	$ 2,156
Net earnings	**384**	255
Dividends on common shares	**(51)**	(42)
Stock-based compensation - retroactive adoption	**-**	(44)
End of period	**$ 3,027**	$ 2,325

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 March 31 **2005**	2004
Operating activities		
Net earnings	**$ 384**	$ 255
Items not affecting cash		
Accretion *(note 4)*	**8**	6
Depletion, depreciation and amortization	**298**	283
Future income taxes	**124**	15
Foreign exchange	**7**	16
Other	**(5)**	1
Settlement of asset retirement obligations	**(5)**	(6)
Change in non-cash working capital *(note 9)*	**(82)**	131
Cash flow - operating activities	**729**	701
Financing activities		
Bank operating loans financing - net	**33**	(38)
Long-term debt issue	**1,422**	56
Long-term debt repayment	**(1,243)**	(73)
Proceeds from exercise of stock options	**1**	13
Dividends on common shares	**(51)**	(42)
Change in non-cash working capital *(note 9)*	**(223)**	6
Cash flow - financing activities	**(61)**	(78)
Available for investing	**668**	623
Investing activities		
Capital expenditures	**(691)**	(583)
Asset sales	**43**	-
Other	**-**	2
Change in non-cash working capital *(note 9)*	**(18)**	(13)
Cash flow - investing activities	**(666)**	(594)
Increase in cash and cash equivalents	**2**	29
Cash and cash equivalents at beginning of period	**7**	3
Cash and cash equivalents at end of period	**$ 9**	$ 32

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

Three months ended March 31, 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 March 31 [1]												
Sales and operating revenues, net of royalties	**$ 888**	$ 781	**$ 353**	$ 246	**$1,386**	$1,438	**$ 437**	$ 360	**$ (863)**	$ (804)	**$ 2,201**	$ 2,021
Costs and expenses												
Operating, cost of sales, selling and general	**240**	225	**195**	212	**1,287**	1,378	**399**	343	**(810)**	(779)	**1,311**	1,379
Depletion, depreciation and amortization	**273**	254	**5**	5	**5**	5	**9**	9	**6**	10	**298**	283
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**10**	17	**10**	17
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**7**	12	**7**	12
	513	479	**200**	217	**1,292**	1,383	**408**	352	**(787)**	(740)	**1,626**	1,691
Earnings (loss) before income taxes	**375**	302	**153**	29	**94**	55	**29**	8	**(76)**	(64)	**575**	330
Current income taxes	**53**	34	**11**	-	**(7)**	12	**(1)**	2	**11**	12	**67**	60
Future income taxes	**83**	32	**35**	6	**39**	6	**12**	1	**(45)**	(30)	**124**	15
Net earnings (loss)	**$ 239**	$ 236	**$ 107**	$ 23	**$ 62**	$ 37	**$ 18**	$ 5	**$ (42)**	$ (46)	**$ 384**	$ 255
Capital employed - As at March 31	**$ 7,917**	$ 6,979	**$ 509**	$ 455	**$ 321**	$ 237	**$ 372**	$ 297	**$ (211)**	$ (103)	**$ 8,908**	$ 7,865
Capital expenditures - Three months ended March 31	**$ 662**	$ 563	**$ 17**	$ 8	**$ 6**	$ 3	**$ 5**	$ 10	**$ 4**	$ 5	**$ 694**	$ 589
Total assets - As at March 31	**$ 11,567**	$ 10,302	**$ 714**	$ 653	**$ 644**	$ 660	**$ 647**	$ 578	**$ 118**	$ 124	**$ 13,690**	$ 12,317

[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:

	Three months ended March 31	
	2005	2004
Asset retirement obligations at beginning of period	**$ 509**	$ 432
Liabilities incurred	**3**	6
Liabilities disposed	**(7)**	-
Liabilities settled	**(5)**	(5)
Accretion	**8**	6
Asset retirement obligations at end of period	**$ 508**	$ 439

At March 31, 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	March 31 2005	Dec. 31 2004	March 31 2005	Dec. 31 2004
		Cdn $ Amount		*U.S. $ Amount*	
Long-term debt					
Syndicated credit facility	2008	**$ 260**	$ 70	**$ -**	$ -
Bilateral credit facilities	2006-8	**50**	40	**-**	-
7.125% notes	2006	**181**	181	**150**	150
8.90% capital securities	2008	**272**	271	**225**	225
6.25% notes	2012	**484**	481	**400**	400
7.55% debentures	2016	**242**	241	**200**	200
6.15% notes	2019	**363**	361	**300**	300
Private placement notes	2005	**18**	18	**15**	15
8.45% senior secured bonds	2005-12	**120**	140	**99**	117
Medium-term notes	2007-9	**300**	300	**-**	-
Total long-term debt		**2,290**	2,103	**$ 1,389**	$ 1,407
Amount due within one year		**(52)**	(56)		
		$ 2,238	$ 2,047		

Interest - net consisted of:

	Three months ended March 31 2005	2004
Long-term debt	**$ 34**	$ 33
Short-term debt	**1**	1
	35	34
Amount capitalized	**(24)**	(17)
	11	17
Interest income	**(1)**	-
	$ 10	$ 17

Foreign exchange consisted of:

	Three months ended March 31 2005	2004
Loss on translation of U.S. dollar denominated long-term debt	**$ 9**	$ 21
Cross currency swaps	**(2)**	(5)
Other gains	**-**	(4)
	$ 7	$ 12

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 - Three months ended March 31, 2004

	As Reported	Change	As Restated
Interest - net	$ 10	$ 7	$ 17
Foreign exchange	8	4	12
Future income taxes	18	(3)	15
Net earnings	263	(8)	255

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:

	Three months ended March 31			
	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	113,812	3	1,026,115	18
Balance at March 31	**423,850,226**	**$ 3,509**	423,201,857	$ 3,498

Stock Options

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

	Three months ended March 31			
	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	60	$ 33.72	45	$ 24.71
Exercised for common shares	(84)	$ 12.44	(994)	$ 13.02
Surrendered for cash	(314)	$ 13.43	-	$ -
Forfeited	(93)	$ 24.99	(24)	$ 18.33
Outstanding, March 31	**9,533**	**$ 23.05**	3,624	$ 14.22
Options exercisable at March 31	**1,127**	**$ 13.31**	2,671	$ 13.00

	March 31, 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	1,082	$ 12.84	1	1,008	$ 12.71
$15.00 - $23.99	445	$ 18.32	3	111	$ 17.91
$24.00 - $24.99	7,641	$ 24.38	4	8	$ 24.23
$25.00 - $33.72	365	$ 31.13	4	-	$ -
	9,533	**$ 23.05**	**4**	**1,127**	**$ 13.31**

Note 8 Earnings per Common Share

	Three months ended March 31	
	2005	2004
Net earnings and net earnings available to common shareholders	**$ 384**	$ 255
Weighted average number of common shares outstanding Basic *(millions)*	**423.8**	422.7
Effect of dilutive stock options and warrants	**-**	2.0
Weighted average number of common shares outstanding Diluted *(millions)*	**423.8**	424.7
Earnings per share		
Basic	**$ 0.91**	$ 0.60
Diluted	**$ 0.91**	$ 0.60

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

	Three months ended March 31	
	2005	2004
a) Change in non-cash working capital was as follows:		
Decrease (increase) in non-cash working capital		
Accounts receivable	**$ (45)**	$ (25)
Inventories	**(54)**	(18)
Prepaid expenses	**(11)**	6
Accounts payable and accrued liabilities	**(213)**	161
Change in non-cash working capital	**(323)**	124
Relating to:		
Financing activities	**(223)**	6
Investing activities	**(18)**	(13)
Operating activities	**$ (82)**	$ 131
b) Other cash flow information:		
Cash taxes paid	**$ 83**	$ 51
Cash interest paid	**$ 30**	$ 30

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended March 31	
	2005	2004
Employer current service cost	**$ 1**	$ 3
Interest cost	**2**	2
Expected return on plan assets	**(2)**	(2)
Amortization of net actuarial losses	**1**	1
	$ 2	$ 4

Note 11 Financial Instruments and Risk Management

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

	March 31 2005	Dec. 31 2004
Commodity price risk management		
Natural gas	**$ (11)**	$ (9)
Power consumption	**1**	(1)
Interest rate risk management		
Interest rate swaps	**37**	52
Foreign currency risk management		
Foreign exchange contracts	**(36)**	(30)

Commodity Price Risk Management

Natural Gas Production

At March 31, 2005, the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for April to December 2005 at an average price of U.S. $1.92 per mcf. During the first quarter of 2005, the impact was a loss of $2 million.

Power Consumption

At March 31, 2005, the Company had hedged power consumption of 148,500 MWh from April to December 2005 at an average fixed price of $49.94 per MWh and 32,760 MWh from April to June 2005 at an average fixed price of $48.00 per MWh. The impact of the hedge program during the first quarter of 2005 was a loss of $0.3 million.

Natural Gas Contracts

At March 31, 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	14,234	$ 17
Physical sale contracts	(14,234)	$ (16)

Interest Rate Risk Management

During the first quarter of 2005, the Company realized a gain of $5 million from interest rate risk management activities.

Foreign Currency Risk Management

During the first quarter of 2005, the Company realized a $3 million loss from all foreign currency risk management activities.

During the first quarter of 2005, Husky recognized a gain of $8 million from its long-dated forwards, which 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 March 31, 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
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 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" 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 Tuesday, April 19, 2005 at 4:15 p.m. Eastern time to discuss Husky's first quarter results which will be released after market close on April 18, 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 21231722. The PostView will be available until Thursday, May 19, 2005.

Media are invited to participate in the call on a listen-only basis by dialing 1-800-428-5596 beginning at 4:05 p.m. Eastern time.

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For further information, please contact:

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