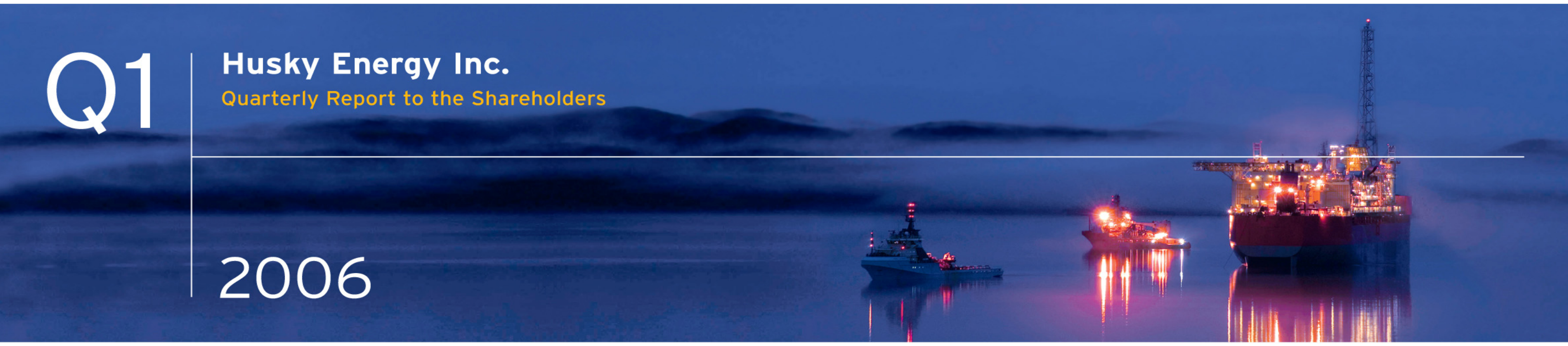
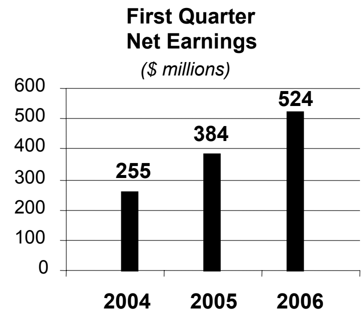
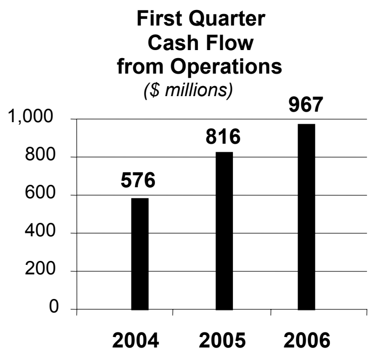
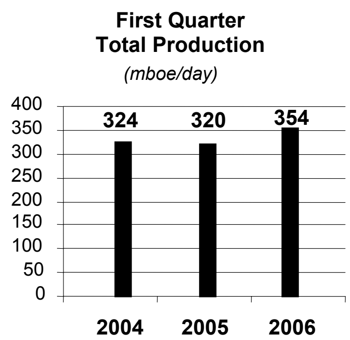


HUSKY ENERGY REPORTS 2006 FIRST QUARTER RESULTS







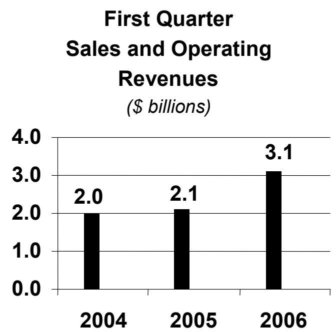
Calgary, Alberta - Husky Energy Inc. reported net earnings of $524 million or $1.24 per share (diluted) in the first quarter of 2006, compared with $384 million or $0.91 per share (diluted) in the same quarter of 2005. Cash flow from operations in the first quarter was $967 million or $2.28 per share (diluted), compared with $816 million or $1.93 per share (diluted) in the same quarter of 2005. Sales and operating revenues, net of royalties, were $3.1 billion in the first quarter of 2006, compared with $2.1 billion in the first quarter of 2005.

"Husky's first quarter results continue to demonstrate the financial and operational strength, and the value the White Rose project brings to the company," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "Husky has benefited from the first quarter production from the White Rose oil field and we look forward to achieving gross production of 100,000 barrels per day by mid-2006."

In the first quarter of 2006, total production averaged 353,600 barrels of oil equivalent (boe) per day, an 11 percent increase, compared with 319,600 boe per day in the first quarter of 2005. Total crude oil and natural gas liquids production was 239,400 barrels (bbls) per day, compared with 206,900 bbls in the first quarter of 2005. Natural gas production was 685.4 million cubic feet (mmcf) per day, compared with 676.2 mmcf per day in the same period last year.

Due to operational issues at Terra Nova, Husky's share of production for the quarter was 9,300 bbls per day compared to 13,700 bbls per day in the first quarter of 2005.

The White Rose oil field had production averaging 46,400 bbls per day net to Husky in the first quarter. The completion of the fourth and fifth production wells during the second quarter will allow total production from the field to reach 100,000 bbls per day.



At the Tucker Oil Sands project, drilling operations for the initial 30 well pairs were completed in February. All structures and major components are in place and overall facility construction is 82 percent complete. The project remains on-time and on-budget with steam scheduled to be injected into the reservoir by the third quarter and first oil is expected by the end of the year.

For the Sunrise Oil Sands project, the program has been focused on delineating the resource along portions of the northern boundary of the lease. Selection of engineering firms for the Front-end Engineering and Design Phase has been initiated.

Evaluation drillings were also conducted on the Caribou and Saleski leases. At Caribou, Husky drilled 15 evaluation wells to better quantify the resources potential. At Saleski, a four-well evaluation program was completed. In April, Husky successfully acquired 23,680 acres of oil sands leases adjacent to its Saleski property. The acquisition increases the potential resources in Saleski to approximately 19.5 billion barrels of original bitumen in place.

In China, Husky has now secured the Transocean Discoverer D-534 drill-ship which is expected to spud a deep-water exploration well on Block 29/26 in the South China Sea in the second quarter. The well is targeting a gas prone structure.

Regarding the Midstream operations, Husky announced in March that it will proceed with the engineering design work to double the capacity of its Lloydminster heavy oil Upgrader to a potential capacity of 150,000 barrels per day. The preliminary estimate for the Upgrader expansion is $2.3 billion. Engineering work is expected to be completed in 15 to 18 months at which time Husky will proceed with the appropriate approvals for the project.

The Upgrader planned turnaround in 2006 has been rescheduled to the spring of 2007. This realignment should enhance both throughput and earnings from the Upgrader in 2006.

For the Refined Products business segment, the Clean Fuels program in the Prince George Refinery is nearing completion. The final phase of the project, which will allow Husky to produce low sulphur diesel, is 90 percent complete and will be operational in May 2006.

The Lloydminster ethanol production project is 88 percent complete and the start-up of this facility is planned for the third quarter of this year. In Minnedosa, construction of the new ethanol production facility is progressing well with plant commissioning to be in the second half of 2007.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

April 17, 2006

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. The readers are also encouraged to refer to Husky's 2005 Annual Information Form, MD&A and Consolidated Financial Statements filed in 2006 with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission ("SEC"), the U.S. regulatory agency. These documents are available at www.sedar.com and at www.sec.gov, respectively.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A the pronouns, "we", "our" and "us" and the term "Husky" denote the corporate entity, Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended March 31, 2006 are compared with results for the three months ended March 31, 2005 and, similarly discussions with respect to Husky's financial position as at March 31, 2006 are compared with its financial position at December 31, 2005.

Additional Reader Guidance

The Consolidated Financial Statements and all financial information included and incorporated by reference in this Interim Report have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties. Prices quoted include or exclude the effect of hedging as indicated.

Forward-looking Statements

This MD&A contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See Section 13.0 "Forward-looking Statements or Information" for additional information.

1.0 SUMMARY OF QUARTERLY RESULTS

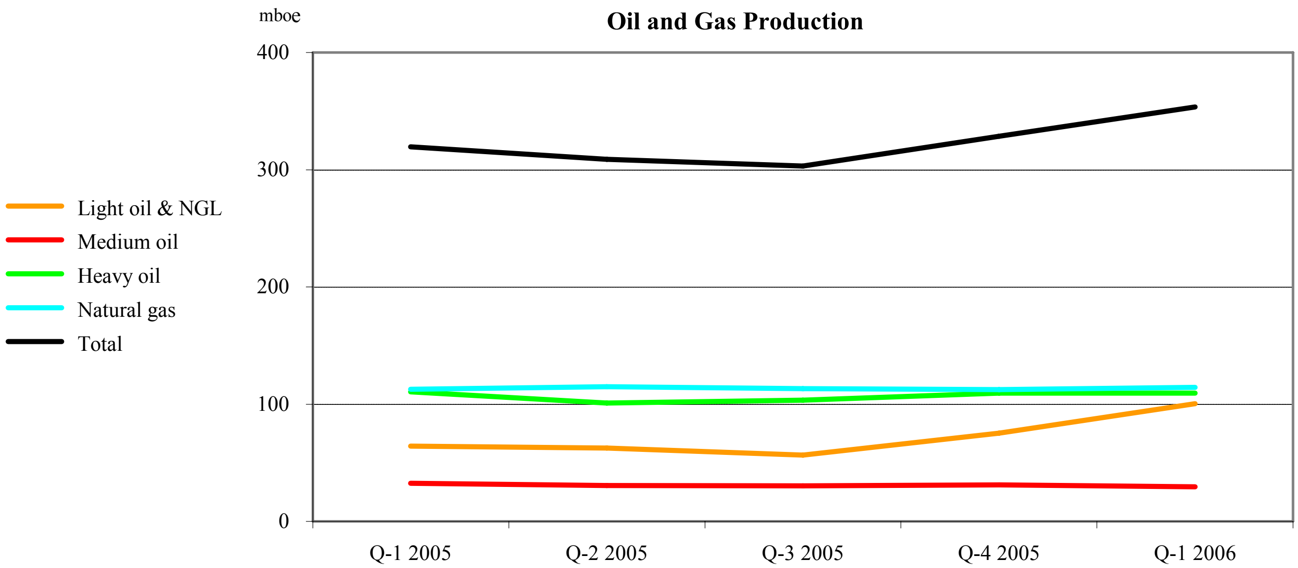
Financial Summary (millions of dollars, except per share amounts and ratios)		**March 31 2006**	Dec. 31 2005	Sept. 30 2005	June 30 2005	March 31 2005	Dec. 31 2004	Sept. 30 2004	June 30 2004
Sales and operating revenues, net of royalties		**$ 3,104**	$ 3,207	$ 2,594	$ 2,350	$ 2,094	$ 2,018	$ 2,191	$ 2,210
Segmented earnings									
Upstream		**$ 412**	$ 533	$ 445	$ 307	$ 239	$ 112	$ 161	$ 204
Midstream		**150**	135	61	130	169	77	50	53
Refined Products		**16**	17	27	20	18	(3)	18	21
Corporate and eliminations		**(54)**	(16)	23	(63)	(42)	39	68	(49)
Net earnings		**$ 524**	$ 669	$ 556	$ 394	$ 384	$ 225	$ 297	$ 229
Per share - Basic		**$ 1.24**	$ 1.58	$ 1.31	$ 0.93	$ 0.91	$ 0.53	$ 0.70	$ 0.54
- Diluted		**1.24**	1.58	1.31	0.93	0.91	0.53	0.70	0.54
Cash flow from operations		**967**	1,197	944	828	816	469	571	581
Per share - Basic		**2.28**	2.82	2.23	1.95	1.93	1.11	1.34	1.37
- Diluted		**2.28**	2.82	2.23	1.95	1.93	1.11	1.34	1.37
Dividends per common share		**0.25**	0.25	0.14	0.14	0.12	0.12	0.12	0.12
Special dividend per common share		**-**	1.00	-	-	-	0.54	-	-
Total assets		**15,859**	15,797	14,712	14,058	13,690	13,240	12,901	12,542
Total long-term debt including current portion		**1,838**	1,886	1,896	2,192	2,290	2,103	2,096	2,229
Return on equity [1]	*(percent)*	**29.6**	29.2	22.9	20.2	18.3	17.0	17.7	16.8
Return on average capital employed [1]	*(percent)*	**23.2**	22.8	17.9	15.3	13.9	13.0	13.4	12.7

Three months ended.

[1] *Calculated for the twelve months ended for the periods shown.*

Daily Production, before Royalties		**March 31 2006**	Dec. 31 2005	Sept. 30 2005	June 30 2005	March 31 2005
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**31.3**	30.1	31.8	31.7	31.9
Medium crude oil		**29.4**	31.0	30.3	30.6	32.4
Heavy crude oil		**109.5**	109.5	103.3	100.9	110.4
		170.2	170.6	165.4	163.2	174.7
East Coast Canada						
Terra Nova - light crude oil		**9.3**	12.2	10.2	13.5	13.7
White Rose - light crude oil		**46.4**	19.0	-	-	-
China						
Wenchang - light crude oil		**13.5**	14.1	14.4	17.3	18.5
		239.4	215.9	190.0	194.0	206.9
Natural gas	*(mmcf/day)*	**685.4**	675.3	679.2	689.3	676.2
Total	*(mboe/day)*	**353.6**	328.5	303.2	308.9	319.6

Three months ended.



Western Canada crude oil production for the first quarter of 2006 remained at the same level as compared with the fourth quarter of 2005. Natural gas sales volume increased by 10 mmcf/day from the fourth quarter of 2005 to the first quarter of 2006. This increase was primarily due to tie-in activity, particularly from shallow gas in the Shackleton/Lacadena area in southwestern Saskatchewan and also additional coalbed methane (natural gas from coalbeds) production in south central Alberta.

White Rose oil field production ramped up during the first quarter of 2006 after start-up in November 2005.

Terra Nova oil field production was 3 mbbls/day lower in the first quarter of 2006 compared with the fourth quarter of 2005 as a result of production decline, drilling delays and protracted maintenance issues.

Wenchang oil field production declined by 0.6 mbbls/day in the first quarter of 2006 compared with the fourth quarter of 2005 reflecting natural reservoir decline.

2.0 Strategic Plans and Capabilities

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.

2.1 Upstream

Gross Production		Three months ended Mar. 31	Full Year Forecast	Three months ended Mar. 31	Year ended Dec. 31
		2006	2006	2005	2005
Crude oil & NGL	*(mbbls/day)*				
Light crude oil & NGL		**100.5**	103 - 116	64.1	64.6
Medium crude oil		**29.4**	29 - 32	32.4	31.1
Heavy crude oil		**109.5**	115 - 120	110.4	106.0
		239.4	247 - 268	206.9	201.7
Natural gas	*(mmcf/day)*	**685.4**	680 - 730	676.2	680.0
Total barrels of oil equivalent	*(mboe/day)*	**353.6**	360 - 390	319.6	315.0

We are currently executing several major corporate-wide initiatives that are intended to result in a substantial long-term increase in enterprise value and position the Company for sustained growth. The upstream business is our most significant segment and, logically, involves strategic plans that are most critical and the largest in scale.

Our conventional upstream operations in the Western Canada Sedimentary Basin ("WCSB") currently provide the majority of our cash flow and are, therefore, foundation assets providing the majority of the funding required to execute our strategic plans. We expect that the production from these projects will more than offset the decline rates of our conventional operations.

As the WCSB continues to mature, the methods employed to manage its still significant conventional oil and gas productive potential are changing, becoming more dependent on increasing exploitation activities involving large aggregate capital expenditures combined with improved prospect imaging tools and drilling techniques. These exploitation activities involve ramping up the drilling of infill and step-out wells, the installation of various types of enhanced recovery techniques, additional plant and infrastructure and the application and further development of emerging technologies. The remaining conventional natural gas reserves lie in smaller pools throughout the WCSB. Our extensive landholdings improve our ability to access these smaller targets.

Declining natural gas production from conventional properties may also be augmented from unconventional operations, two of which are now economically attractive: coalbed methane and tight gas (reserves with low permeability). In addition, we have natural gas potential in new basins that are now entering the pre-development phase. We have discoveries and prospects in the central Mackenzie Valley in Canada's Northwest Territories, offshore eastern Canada and offshore Indonesia.

Declining crude oil production from conventional properties in the WCSB, including heavy crude oil primarily located in the Lloydminster area, is expected to be offset by development of our properties in the oil sands areas of Alberta and discoveries and exploration prospects offshore eastern Canada, the Northwest Territories and offshore China.

We also maintain an exploration program that is focused on natural gas prospects in the deep basin and the foothills and northern regions of Alberta and British Columbia. Since 2000 we have invested an average of $160 million per year exploring these regions with encouraging results.

In addition to upstream initiatives we are in the process of implementing new midstream and refined products projects that expand and optimize our productive capacity.

White Rose Oil Field

The White Rose oil field commenced production in November 2005 from three wells, with six seawater injection wells providing pressure support and one gas injection well for gas storage. During the first quarter of 2006 crude oil sales from the White Rose field totalled 6 million gross barrels. At the end of the first quarter two additional production wells and one water injector had finished drilling, and following completion operations are expected to be on-line by the end of second quarter 2006. These wells will increase White Rose production capacity above 100 mbbls/day (72.5 mbbls/day net to Husky). Delineation of the White Rose oil field will continue in 2006 with two delineation wells planned to evaluate potential extension of the reservoirs to the west and south-west.

Tucker Oil Sands Project

At the Tucker Oil Sands project, drilling operations for the initial 30 well pairs was completed in February. Drilling continues on two additional well pairs, which we elected to drill while the rig is at the site. It is expected that all drilling activities will be complete in April. Overall facility construction is 82 percent complete. All structures and major components are in place and work is currently focused on piping, electrical and instrumentation. Installation of the five steam generators is progressing. The Central Control Complex has been handed over to Husky and approximately 66 percent of the operating staff have been hired and are engaged in training and facility commissioning activities. The project remains on-schedule to produce first oil in 2006.

Sunrise Oil Sands Project

At Sunrise, the winter drilling program is complete. The program focused on delineating resource along portions of the northern boundary of the lease, on source water exploration and on water disposal well drilling and testing. Sufficient water disposal capacity has been confirmed. The process to select engineering firms for the front-end engineering design was initiated, which will assist Husky in finalizing the project scope, schedule, and cost estimate in support of project sanction. Planning work also continued on two joint industry efforts; a shared airstrip and access highway. The preferred location for the airstrip has been identified and discussions are underway regarding the design and ownership structure. Discussions on the access highway were held with government officials with respect to cost sharing and the eligibility of road expenditures for royalty deduction.

Caribou and Saleski

Evaluation drilling was conducted this winter on the Caribou and Saleski leases. At Caribou we drilled 15 evaluation wells to better quantify the resource potential. At Saleski a four well evaluation program was completed.

Husky acquired two oil sands leases in the Saleski area of northern Alberta at the April 5, 2006 Alberta land sale (Leases L0490 and L0491 located in Ranges 19 & 20, Township 88 W4M). Combined, the leases total 23,680 acres and are estimated to contain 2.68 billion barrels of bitumen in place within the Grosmont carbonate. The acquired lands are adjacent to Husky's existing holdings in the Saleski area and resulted in an increase in Husky's total land holdings from 154,880 acres to 178,560 acres (or from 242 sections to 279 sections) and increased Husky's bitumen in place estimates for Saleski from 16.80 billion barrels to 19.48 billion barrels.

Western Canada Sedimentary Basin Exploration

In the first quarter of 2006 we drilled 256 gross (154 net) wells in the WCSB resulting in 25 gross (21 net) oil wells and 181 gross (85 net) gas wells. In the natural gas prone deep basin, foothills and northern plains areas we drilled 20 gross (13 net) wells resulting in 18 gross (12 net) natural gas wells. At March 31, 2006, 10 gross (7 net) wells were drilling or suspended in these regions.

Northwest Territories Exploration

In the Northwest Territories we completed the drilling of the K-44 delineation well to the Summit Creek B-44 discovery and the Stewart D-57 exploration well. We are evaluating the well results.

East Coast Canada Exploration

A seismic vessel has been contracted to finish the 3-D seismic program in the Jeanne d'Arc Basin that was halted last fall due to inclement weather. This program, along with additional 3-D seismic shooting in the vicinity of the White Rose oil field, will commence this summer.

China Exploration

In China, the Transocean Discoverer D-534 drill-ship is expected to spud a deep-water exploration well on Block 29/26 in the second quarter of 2006.

Also, in China, we are seeking tenders on a rig to drill an exploration well on Block 04/35 in the East China Sea. The well is planned for late 2006.

Indonesia Natural Gas Development

At Madura, Indonesia, the conceptual design for the BD natural gas field development has been submitted to the Indonesian regulatory agency, BPMIGAS, for consideration. Negotiations on a gas sales agreement and extension of the production sharing agreement are underway. Completion of this project is contingent on the timing of governmental approval.

2.2 MIDSTREAM

Lloydminster Upgrader

At the Lloydminster Upgrader the front-end engineering and design with respect to plans to expand throughput capacity from approximately 80 to 150 mbbls/day of synthetic crude oil and diluent commenced. The plans also include modifications to the Upgrader that will permit processing a 67 percent Cold Lake bitumen feedstock mix. The design work is expected to be completed by the third quarter of 2007. Completion of the expansion project could be achieved by the end of 2010, subject to project sanction.

2.3 REFINED PRODUCTS

Prince George Refinery Low Sulphur Upgrade

At the Prince George refinery the second phase of modifications is progressing and is on-schedule to produce low sulphur diesel fuel before the end of the second quarter. The first phase, modifications to produce low sulphur gasoline, was completed and has been on-line since August 2005. The final phase of the project will result in increased processing capacity to 12 mbbls/day, 20 percent based on nameplate capacity.

Lloydminster and Minnedosa Ethanol Plants

To meet the increasing demand for ethanol blended gasoline (known as E15 gasoline) we are currently constructing two motor fuel grade ethanol plants. One plant is located adjacent to our Upgrader at Lloydminster, Saskatchewan and the other at Minnedosa, Manitoba, the site of our existing ethanol plant. Each plant will have the same throughput capacity, producing a combined 260 million litres of ethanol per year.

The Lloydminster plant is approximately 88 percent complete and on-schedule for start-up in the third quarter of 2006.

The Minnedosa plant is approximately 10 percent complete and is expected to be complete during the second quarter of 2007.

3.0 BUSINESS ENVIRONMENT

Husky's financial results are significantly influenced by its business environment. Average quarterly market prices were:

Average Benchmark Prices and U.S. Exchange Rate		Three months ended				
		March 31 2006	Dec. 31 2005	Sept. 30 2005	June 30 2005	March 31 2005
WTI crude oil [1]	*(U.S. $/bbl)*	**63.48**	60.02	63.10	53.17	49.84
Brent	*(U.S. $/bbl)*	**61.75**	56.90	61.54	51.58	47.50
Canadian par light crude 0.3% sulphur	*($/bbl)*	**69.40**	71.65	77.04	66.43	62.02
Lloyd @ Lloydminster heavy crude oil	*($/bbl)*	**26.25**	29.60	44.13	27.95	22.62
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**8.98**	12.97	8.49	6.73	6.27
NIT natural gas	*($/GJ)*	**8.79**	11.08	7.75	6.99	6.34
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**29.20**	24.24	18.90	21.27	19.57
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.866**	0.852	0.833	0.804	0.815

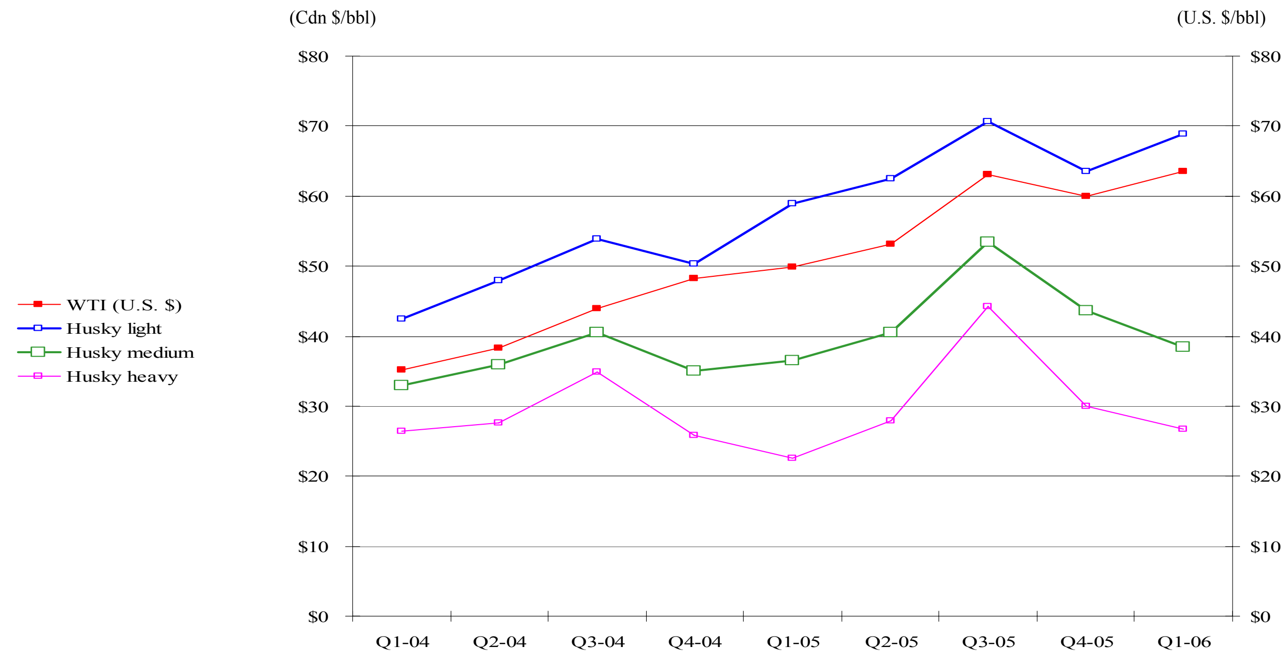
[1] *Prices quoted are near-month contract prices for settlement during the next month.*

3.1 COMMODITY PRICE RISK

Our earnings depend largely on the profitability of our upstream business segment which is most significantly affected by fluctuations in oil and gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond our control. The effect of any single risk is not determinable with certainty as these are interdependent and our future course of action depends upon our assessment of all information available at that time.

Crude Oil

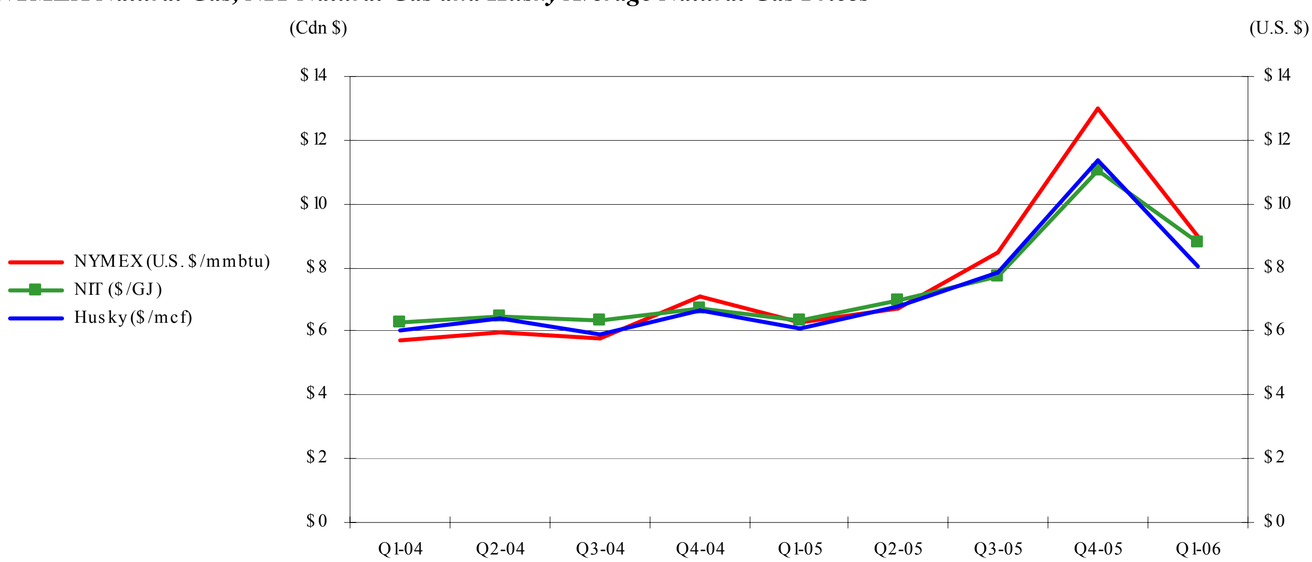
WTI and Husky Average Crude Oil Prices



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

Natural Gas

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



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.

Natural gas prices drifted lower throughout the first quarter of 2006. The NYMEX near month quote at the beginning of the quarter was U.S. $10.63/mmbtu and at the end of the quarter it was U.S. $7.49/mmbtu. During the quarter natural gas supplies were historically high and the volume of natural gas in storage in the United States grew throughout the quarter from seven percent above five year averages to 63 percent above five year averages.

Upgrading Differential

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

Refined Products Margins

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

Integration

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

3.2 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 March 31, 2006, 81 percent or $1.5 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 2006 was $1.1671. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 47 percent when cross currency swaps are included. Refer to the section "Financial and Derivative Instruments."

3.3 Interest Rate RISK

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."

3.4 ENVIRONMENTAL REGULATION RISK

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

3.5 POLITICAL RISK

In addition to commodity price risk, Husky's 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 laws or policies affecting trade or investment.

3.6 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 first quarter of 2006. 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	2006 First Quarter Average	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
			($ millions)	*($/share)* [5]	*($ millions)*	*($/share)* [5]
Upstream and Midstream						
WTI benchmark crude oil price	63.48	*U.S. $1.00/bbl*	88	0.21	57	0.13
NYMEX benchmark natural gas price [1]	8.98	*U.S. $0.20/mmbtu*	33	0.08	21	0.05
WTI/Lloyd crude blend differential [2]	29.20	*U.S. $1.00/bbl*	(31)	(0.07)	(20)	(0.05)
Exchange rate (U.S. $ per Cdn $) [3]	0.866	*U.S. $0.01*	(64)	(0.15)	(42)	(0.10)
Refined Products						
Light oil margins	0.029	*Cdn $0.005/litre*	15	0.04	10	0.02
Asphalt margins	12.48	*Cdn $1.00/bbl*	6	0.01	4	0.01
Consolidated						
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	0.857 [4]	*U.S. $0.01*	-	-	9	0.02

(1) *Includes decrease in earnings related to natural gas consumption.*

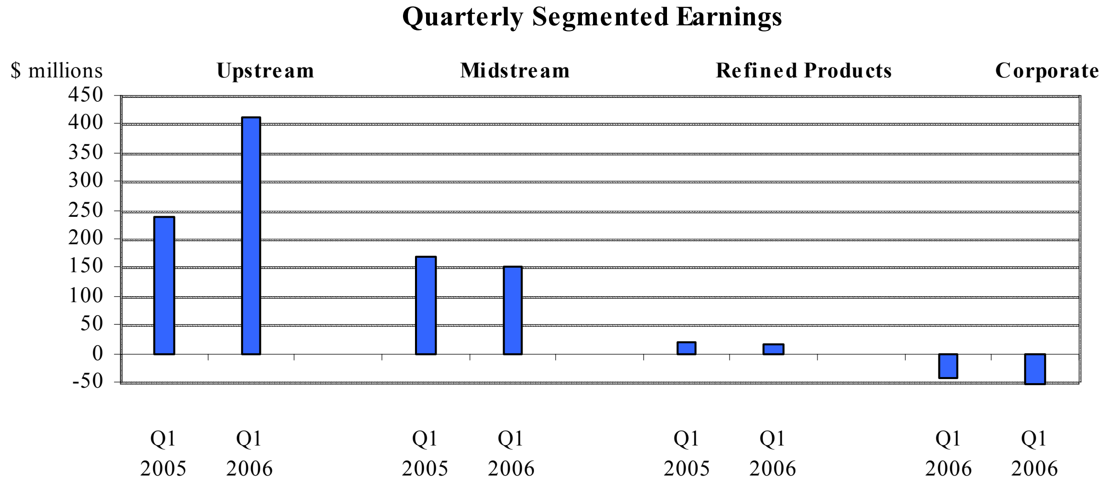
(2) *Includes impact of upstream and upgrading operations only.*

(3) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.*

(4) *U.S./Canadian dollar exchange rate at March 31, 2006.*

(5) *Based on March 31, 2006 common shares outstanding of 424.2 million.*

4.0 RESULTS OF OPERATIONS



4.1 UPSTREAM

Upstream Earnings Summary	Three months ended March 31	
(millions of dollars)	**2006**	2005
Gross revenues	**$ 1,493**	$ 1,040
Royalties	**206**	152
Net revenues	**1,287**	888
Operating and administration expenses	**311**	240
Depletion, depreciation and amortization	**351**	273
Income taxes	**213**	136
Earnings	**$ 412**	$ 239

Net Revenue Variance Analysis

(millions of dollars)	Crude oil & NGL	Natural gas	Other	Total
Three months ended March 31, 2005	$ 572	$ 300	$ 16	$ 888
Price changes	135	125	-	260
Volume changes	180	5	-	185
Royalties	(23)	(31)	-	(54)
Processing and sulphur	-	-	8	8
Three months ended March 31, 2006	**$ 864**	**$ 399**	**$ 24**	**$ 1,287**

First Quarter

Upstream earnings were $173 million higher in the first quarter of 2006 than in the first quarter of 2005 as a result of the following factors:

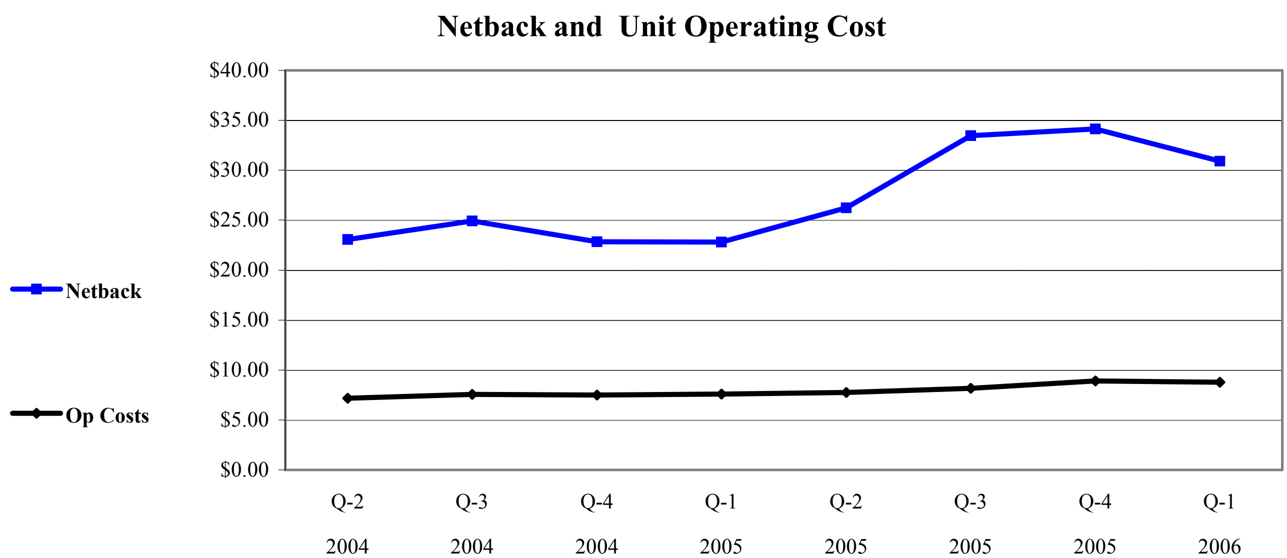
- higher sales volume of light crude oil and natural gas; and
- higher light, medium and heavy crude oil and natural gas prices.

Partially offset by:

- lower sales volume of medium and heavy crude oil;
- higher unit operating costs;
- higher unit depletion, depreciation and amortization; and
- higher income taxes.

Unit Operating Costs

Unit operating costs were 16 percent higher in the first quarter of 2006 compared with the same period in 2005 due to higher energy costs, increased natural gas compression costs, higher natural gas well count and production declines. In addition, high commodity prices are affecting rates charged by our service providers with the high level of industry activity creating tight service markets.



Unit Depletion, Depreciation and Amortization

Unit depletion, depreciation and amortization expense increased 16 percent in the first quarter of 2006 compared with the same period in 2005. The increase was primarily due to a higher capital base in 2006 as a result of increased requirements for production maintenance capital for our properties in the WCSB, and the start-up of the White Rose oil field, which, since it is an offshore development, has a higher ratio of capital to reserves. In addition, the higher commodity prices, as with operating costs, increased the cost of materials and services in our capital costs.

Average Sales Prices		Three months ended March 31	
		2006	2005
Crude Oil	*($/bbl)*		
Light crude oil & NGL		**$ 67.04**	$ 56.43
Medium crude oil		**38.39**	36.50
Heavy crude oil		**26.73**	22.53
Total average		**45.08**	35.22
Natural Gas	*($/mcf)*		
Average		**8.06**	6.07

Effective Royalty Rates	Three months ended March 31	
Percentage of upstream sales revenues	**2006**	2005
Crude oil & NGL	**11%**	12%
Natural gas	**20%**	19%
Total	**14%**	15%

Upstream Revenue Mix	Three months ended March 31	
Percentage of upstream sales revenues, after royalties	**2006**	2005
Light crude oil & NGL	**43%**	32%
Medium crude oil	**7%**	10%
Heavy crude oil	**18%**	23%
Natural gas	**32%**	35%
	100%	100%

Operating Netbacks

Western Canada

Light Crude Oil Netbacks [1]	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 60.48**	$ 50.83
Royalties	**5.46**	5.01
Operating costs	**11.80**	9.86
Netback	**$ 43.22**	$ 35.96

Medium Crude Oil Netbacks [1]	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 38.52**	$ 36.42
Royalties	**6.29**	6.41
Operating costs	**12.51**	10.53
Netback	**$ 19.72**	$ 19.48

Heavy Crude Oil Netbacks [1]	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 26.97**	$ 22.70
Royalties	**3.10**	2.19
Operating costs	**11.22**	9.24
Netback	**$ 12.65**	$ 11.27

Natural Gas Netbacks [2]	Three months ended March 31	
Per mcfge	**2006**	2005
Sales revenues	**$ 8.05**	$ 6.17
Royalties	**1.90**	1.39
Operating costs	**0.99**	0.95
Netback	**$ 5.16**	$ 3.83

Total Western Canada Upstream Netbacks [1]	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 40.18**	$ 32.95
Royalties	**7.03**	5.34
Operating costs	**9.31**	8.11
Netback	**$ 23.84**	$ 19.50

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

Terra Nova Crude Oil Netbacks	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 67.39**	$ 60.73
Royalties	**18.63**	3.02
Operating costs	**7.85**	3.93
Netback	**$ 40.91**	$ 53.78

White Rose Crude Oil Netbacks	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 70.11**	$ -
Royalties	**0.69**	-
Operating costs	**7.25**	-
Netback	**$ 62.17**	$ -

Total Canada Netbacks	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 45.00**	$ 36.91
Royalties	**6.48**	5.25
Operating costs	**8.99**	7.31
Netback	**$ 29.53**	$ 24.35

Wenchang Crude Oil Netbacks	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 73.65**	$ 58.94
Royalties	**5.96**	5.43
Operating costs	**3.52**	2.38
Netback	**$ 64.17**	$ 51.13

Total Upstream Segment Netbacks (1)	Three months ended March 31	
Per boe	**2006**	2005
Sales revenues	**$ 46.13**	$ 35.65
Royalties	**6.46**	5.25
Operating costs	**8.78**	7.60
Netback	**$ 30.89**	$ 22.80

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

Upstream Capital Expenditures

Capital Expenditures Summary [1]	Three months ended March 31	
(millions of dollars)	**2006**	2005
Exploration		
Western Canada	**$ 167**	$ 129
East Coast Canada and Frontier	**21**	4
International	**1**	4
	189	137
Development		
Western Canada	**513**	403
East Coast Canada	**52**	120
International	**3**	2
	568	525
	$ 757	$ 662

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

Upstream capital expenditures totaled $757 million, 88 percent of total consolidated capital expenditures during the first three months of 2006 compared with $662 million or 95 percent of the total, during the first three months of 2005.

Western Canada Wells Drilled [1] [2]		Three months ended March 31			
		2006		2005	
		Gross	**Net**	Gross	Net
Exploration	Oil	**25**	**21**	25	22
	Gas	**181**	**85**	96	72
	Dry	**50**	**48**	14	14
		256	**154**	135	108
Development	Oil	**128**	**112**	66	61
	Gas	**241**	**189**	231	221
	Dry	**9**	**9**	10	10
		378	**310**	307	292
Total		**634**	**464**	442	400

[1] *Excludes stratigraphic test wells.*
[2] *Includes non-operated wells.*

4.2 MIDSTREAM

Upgrading Earnings Summary		Three months ended March 31	
(millions of dollars, except where indicated)		**2006**	2005
Gross margin		**$ 208**	$ 207
Operating costs		**66**	50
Other recoveries		**(1)**	(1)
Depreciation and amortization		**6**	5
Income taxes		**44**	46
Earnings		**$ 93**	$ 107
Selected operating data:			
Upgrader throughput [1]	*(mbbls/day)*	**71.3**	72.1
Synthetic crude oil sales	*(mbbls/day)*	**63.4**	63.9
Upgrading differential	*($/bbl)*	**$ 34.82**	$ 32.09
Unit margin	*($/bbl)*	**$ 36.38**	$ 35.91
Unit operating cost [2]	*($/bbl)*	**$ 10.24**	$ 7.70

[1] *Throughput includes diluent returned to the field.*
[2] *Based on throughput.*

Upgrading Earnings Variance Analysis	
(millions of dollars)	
Three months ended March 31, 2005	$ 107
Volume	(2)
Margin	3
Operating costs - energy related	(9)
Operating costs - non-energy related	(7)
Depreciation and amortization	(1)
Income taxes	2
Three months ended March 31, 2006	**$ 93**

First Quarter

Upgrading earnings decreased in the first quarter of 2006 by $14 million compared with the first quarter of 2005 due to:

- lower sales volume of synthetic crude oil; and
- higher unit operating costs both energy and non-energy related.

Partially offset by:

- wider upgrading differential.

Infrastructure and Marketing Earnings Summary	Three months ended March 31	
(millions of dollars, except where indicated)	**2006**	2005
Gross margin - pipeline	**$ 26**	$ 25
- other infrastructure and marketing	**68**	77
	94	102
Other expenses	**2**	3
Depreciation and amortization	**6**	5
Income taxes	**29**	32
Earnings	**$ 57**	$ 62
Selected operating data:		
Aggregate pipeline throughput *(mbbls/day)*	**500**	510

First Quarter

Infrastructure and marketing earnings decreased by $5 million in the first quarter of 2006 compared with the first quarter of 2005 due to:

- lower income associated with crude and blend crude oil marketing.

Partially offset by:

- higher income from natural gas commodity marketing;
- higher pipeline margins; and
- lower income taxes.

Midstream Capital Expenditures

Midstream capital expenditures totaled $38 million in the first quarter of 2006, $37 million at the Lloydminster Upgrader, primarily for debottleneck and reliability projects and $1 million on various pipeline and infrastructure work.

4.3 REFINED PRODUCTS

Refined Products Earnings Summary		Three months ended March 31	
(millions of dollars, except where indicated)		**2006**	2005
Gross margin	- fuel sales	**$ 22**	$ 29
	- ancillary sales	**8**	7
	- asphalt sales	**21**	19
		51	55
Operating and other expenses		**16**	17
Depreciation and amortization		**10**	9
Income taxes		**9**	11
Earnings		**$ 16**	$ 18
Selected operating data:			
Number of fuel outlets		**514**	523
Light oil sales	*(million litres/day)*	**8.6**	8.3
Light oil retail sales per outlet	*(thousand litres/day)*	**12.9**	12.4
Prince George refinery throughput	*(mbbls/day)*	**9.3**	10.0
Asphalt sales	*(mbbls/day)*	**17.7**	17.7
Lloydminster refinery throughput	*(mbbls/day)*	**27.1**	27.1

First Quarter

Refined products earnings decreased by $2 million in the first quarter of 2006 compared with the first quarter of 2005 due to:

- lower marketing margins for gasoline and distillates; and
- higher depreciation expense.

Partially offset by:

- higher marketing margins for asphalt products; and
- lower income taxes.

Refined Products Capital Expenditures

Refined Products capital expenditures totaled $64 million in the first quarter of 2006, $15 million at the Prince George refinery, $41 million at the Lloydminster ethanol plant and $8 million at the Minnedosa ethanol plant.

4.4 CORPORATE

Corporate Summary *(millions of dollars) income (expense)*	Three months ended March 31 **2006**	2005
Intersegment eliminations - net	**$ 9**	$ (23)
Administration expenses	**(4)**	(6)
Stock-based compensation	**(70)**	(21)
Other - net	**(4)**	(3)
Depreciation and amortization	**(6)**	(6)
Interest on debt	**(38)**	(34)
Interest capitalized	**11**	24
Foreign exchange	**5**	(7)
Income taxes	**43**	34
Loss	**$ (54)**	$ (42)

First Quarter

Corporate expense increased by $12 million in the first quarter of 2006 compared with the first quarter of 2005 due to:

- higher stock-based compensation expense during the first quarter of 2006;
- lower capitalized interest due to start-up of the White Rose oil field; and
- higher interest costs.

Partially offset by:

- gains on translation of U.S. denominated debt in the first quarter 2006 compared with losses in the first quarter of 2005; and
- higher income tax recovery.

Foreign Exchange Summary *(millions of dollars)*	Three months ended March 31 **2006**	2005
(Gain) loss on translation of U.S. dollar denominated long-term debt		
Realized	**$ (31)**	$ (4)
Unrealized	**30**	13
	(1)	9
Cross currency swaps	**(1)**	(2)
Other gains	**(3)**	-
	$ (5)	$ 7
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $0.858**	U.S. $0.831
At end of period	**U.S. $0.857**	U.S. $0.827

Consolidated Income Taxes

The effective tax rate was as follows:

	Three months ended March 31	
	2006	2005
Effective tax rate	**32.5%**	33.2%

Corporate Capital Expenditures

Corporate capital expenditures totaled $6 million in the first quarter of 2006 primarily for various office and information system upgrades.

5.0 Liquidity and Capital Resources

5.1 Operating Activities

In the first quarter of 2006, cash generated from operating activities amounted to $1,124 million compared with $729 million in the first quarter of 2005. Higher cash flow from operating activities was primarily due to higher commodity prices and higher change in non-cash working capital.

5.2 Financing Activities

In the first quarter of 2006, cash used in financing activities amounted to $509 million compared with $61 million in the first quarter of 2005. During the first quarter of 2006, higher dividends and non-cash working capital associated with financing activities primarily resulted in a higher use of cash compared with the first quarter of 2005. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

On February 1, 2006 Husky redeemed its 8.45 percent senior secured bonds for U.S. $85 million. These bonds were issued in July 1999 to finance the development of the Terra Nova oil field offshore Newfoundland.

5.3 Investing Activities

In the first quarter of 2006, cash used in investing activities amounted to $860 million compared with $666 million in the first quarter of 2005. Cash was used primarily for capital expenditures partially offset by proceeds from asset sales.

5.4 Sources of Capital

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash 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 revenue to protect cash flow.

Sources and Uses of Cash *(millions of dollars)*	Three months ended March 31 **2006**	Year ended December 31 2005
Cash sourced		
Cash flow from operations [1]	**$ 967**	$ 3,785
Debt issue	**1,037**	3,235
Asset sales	**32**	74
Proceeds from exercise of stock options	**1**	6
Proceeds from monetization of financial instruments	**-**	39
	2,037	7,139
Cash used		
Capital expenditures	**860**	3,068
Debt repayment	**1,022**	3,450
Special dividend on common shares	**-**	424
Ordinary dividends on common shares	**106**	276
Settlement of asset retirement obligations	**8**	41
Other	**1**	32
	1,997	7,291
Net cash (deficiency)	**40**	(152)
Increase (decrease) in non-cash working capital	**(285)**	394
Increase in cash and cash equivalents	**(245)**	242
Cash and cash equivalents - beginning of period	**249**	7
Cash and cash equivalents - end of period	**$ 4**	$ 249
Increase (decrease) in non-cash working capital		
Cash positive working capital change		
Accounts receivable decrease	**$ 104**	$ -
Inventory decrease	**32**	-
Prepaid expense decrease	**4**	17
Accounts payable and accrued liabilities increase	**-**	984
	140	1,001
Cash negative working capital change		
Accounts receivable increase	**-**	410
Inventory increase	**-**	197
Accounts payable and accrued liabilities decrease	**425**	-
	425	607
Increase (decrease) in non-cash working capital	**$ (285)**	$ 394

[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, 2006, our working capital deficiency was $1.0 billion, unchanged from the deficiency at December 31, 2005.

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	March 31, 2006		
	Outstanding		Available
(millions of dollars)	*(U.S. $)*	*(Cdn $)*	*(Cdn $)*
Short-term bank debt	$ 4	$ 62	$ 121
Long-term bank debt			
Syndicated credit facility	-	-	1,000
Bilateral credit facilities	-	50	100
Medium-term notes	-	300	
Capital securities	225	263	
U.S. public notes	1,050	1,225	
Total short-term and long-term debt	$ 1,279	$ 1,900	$ 1,221
Common shares and retained earnings		$ 7,941	

Financial Ratios	Three months ended March 31	
(millions of dollars, except ratios)	**2006**	2005
Cash flow - operating activities	**$ 1,124**	$ 729
- financing activities	**$ (509)**	$ (61)
- investing activities	**$ (860)**	$ (666)
Debt to capital employed *(percent)*	**19.3**	26.6
Corporate reinvestment ratio (1) (2)	**0.8**	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.

5.5 Contractual Obligations and Commercial Commitments

Refer to Husky's 2005 annual Management's Discussion and Analysis under the caption "Cash Requirements" which summarizes contractual obligations and commercial commitments. There has been no material change in these amounts as at March 31, 2006.

5.6 Off Balance Sheet Arrangements

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

We engage in the ordinary course of business in the securitization of accounts receivable. Our receivable securitization program is fully utilized at $350 million and the 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.

6.0 TRANSACTIONS WITH RELATED PARTIES

We did not have any significant transactions with related parties during the first three months of 2006 or during the year ended December 31, 2005.

7.0 SIGNIFICANT CUSTOMERS

We did not have any customers that constituted more than 10 percent of total sales and operating revenues during the first three months of 2006.

8.0 FINANCIAL AND DERIVATIVE INSTRUMENTS

Husky is exposed to market risks related to commodity prices, interest rates and foreign exchange rates as discussed under Section 3.0 "Business Environment". From time to time, we use financial and derivative instruments to manage our exposure to these risks.

8.1 POWER CONSUMPTION

At March 31, 2006, we had hedged power consumption as follows:

(millions of dollars, except where indicated)	Notional Volumes *(MW)*	Term	Price	Unrecognized Gain (Loss)
Fixed price purchase	19.0	Apr. to Aug. 2006	$ 62.50/MWh	$ (0.4)
	19.0	Apr. to Sept. 2006	$ 63.00/MWh	(0.4)
	38.0	Oct. to Dec. 2006	$ 62.95/MWh	0.2
				$ (0.6)

8.2 FOREIGN CURRENCY RISK MANAGEMENT

At March 31, 2006, we had the following cross currency debt swaps in place:

- U.S. $150 million at 7.125 percent swapped at $1.45 to $218 million at 8.74 percent until November 15, 2006.
- U.S. $150 million at 6.250 percent swapped at $1.41 to $212 million at 7.41 percent until June 15, 2012.
- U.S. $75 million at 6.250 percent swapped at $1.19 to $90 million at 5.65 percent until June 15, 2012.
- U.S. $50 million at 6.250 percent swapped at $1.17 to $59 million at 5.67 percent until June 15, 2012.
- U.S. $75 million at 6.250 percent swapped at $1.17 to $88 million at 5.61 percent until June 15, 2012.

At March 31, 2006 the cost of a U.S. dollar in Canadian currency was $1.1671.

In the first three months of 2006, the cross currency swaps resulted in an increase to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $1 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains of $1 million in the first three months of 2006.

8.3 INTEREST RATE RISK MANAGEMENT

In the first three months of 2006, the interest rate risk management activities resulted in a decrease to interest expense of $1 million.

The cross currency swaps resulted in an addition to interest expense of $2 million in the first three months of 2006.

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 three months of 2006, these swaps resulted in an offset to interest expense amounting to $1 million.

The amortization of previous interest rate swap terminations resulted in an additional $2 million offset to interest expense in the first three months of 2006.

9.0 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, 2005 available at www.sedar.com.

10.0 NEW ACCOUNTING STANDARDS

Effective January 1, 2006, we adopted the revised recommendations of the Canadian Institute of Chartered Accountants section 3831, "Non-monetary Transactions" which replaced section 3830 of the same name. The new recommendations require that all non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business. The guidance was effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006.

11.0 OUTSTANDING SHARE DATA

(in thousands, except per share amounts)		Three months ended March 31 **2006**	Year ended December 31 2005
Share price [1]	High	**$ 74.50**	$ 69.95
	Low	**$ 59.63**	$ 32.30
	Close at end of period	**$ 70.65**	$ 59.00
Average daily trading volume		**618**	664
Weighted average number of common shares outstanding			
	Basic	**424,147**	423,964
	Diluted	**424,147**	423,964
Issued and outstanding at end of period [2]			
Number of common shares		**424,171**	424,125
Number of stock options		**7,094**	7,285
Number of stock options exercisable		**1,152**	1,533

(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, 2006 to April 11, 2006.

12.0 NON-GAAP MEASURES

Disclosure of Cash Flow from Operations

Management's Discussion and Analysis contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with generally accepted accounting principles as an indicator of our financial performance. Our determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

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

		Three months ended March 31	Year ended December 31
(millions of dollars)		**2006**	2005
Non-GAAP	Cash flow from operations	**$ 967**	$ 3,785
	Settlement of asset retirement obligations	**(8)**	(41)
	Change in non-cash working capital	**165**	(72)
GAAP	Cash flow - operating activities	**$ 1,124**	$ 3,672

13.0 FORWARD-LOOKING STATEMENTS OR INFORMATION

Certain statements in this Interim Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, and Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in forward-looking statements made in this Interim Report. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. In particular, our construction plans for the Tucker in-situ oil sands project, the Prince George refinery low sulphur upgrade, the Lloydminster ethanol plant and Minnedosa ethanol plant; our plans to proceed with our front-end engineering and design and preliminary cost estimates with respect to the Lloydminster Upgrader expansion; our design plans for the Sunrise in-situ oil sands project; our exploration and development drilling plans for Western Canada and the Northwest Territories; our China exploration drilling plans; our estimates of the productive capacity for White Rose, our crude oil production plans, our East Coast seismic program and drilling plans, the timing of the turnaround for the Upgrader and the completion of the Upgrader debottleneck project and our plans to develop our Madura Strait PSC, are forward-looking statements. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Interim Report. Among the key factors that have a direct bearing on the Company's results of operations are the nature of the Company's involvement in the business of exploration, development and production of oil and natural gas reserves and the fluctuation of the exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under "Management's Discussion and Analysis".

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which 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 restrictions in areas where we operate;
- the ability and willingness of parties with whom we have material relationships to fulfill their obligations; and
- 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 and that may or may not be financially recoverable.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

14.0 CAUTIONARY NOTE REQUIRED BY NATIONAL INSTRUMENTS 51-101

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

15.0 CAUTIONARY NOTE TO U.S. INVESTORS

The United States Securities and Exchange Commission permits U.S. oil and gas companies, in their filings with the SEC, to disclose only proved reserves that the company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this Interim Report, Husky refers to "in place" which are inherently more uncertain than proved reserves and which U.S. oil and gas companies are prohibited from including in reports filed with the SEC.

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars)	**March 31 2006**	December 31 2005
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 4**	$ 249
Accounts receivable	**752**	856
Inventories	**439**	471
Prepaid expenses	**38**	40
	1,233	1,616
Property, plant and equipment - (full cost accounting)	**23,198**	22,375
Less accumulated depletion, depreciation and amortization	**8,785**	8,416
	14,413	13,959
Goodwill	**160**	160
Other assets	**53**	62
	$ 15,859	$ 15,797
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans	**$ 62**	$ -
Accounts payable and accrued liabilities	**1,940**	2,391
Long-term debt due within one year *(note 5)*	**275**	274
	2,277	2,665
Long-term debt *(note 5)*	**1,563**	1,612
Other long-term liabilities *(note 4)*	**760**	730
Future income taxes	**3,318**	3,270
Commitments and contingencies *(note 6)*		
Shareholders' equity		
Common shares *(note 7)*	**3,526**	3,523
Retained earnings	**4,415**	3,997
	7,941	7,520
	$ 15,859	$ 15,797
Common shares outstanding *(millions) (note 7)*	**424.2**	424.1

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Earnings

(millions of dollars, except per share amounts) (unaudited)	Three months ended March 31 **2006**	2005
Sales and operating revenues, net of royalties	**$ 3,104**	$ 2,094
Costs and expenses		
Cost of sales and operating expenses	**1,827**	1,151
Selling and administration expenses	**27**	29
Stock-based compensation	**70**	21
Depletion, depreciation and amortization	**379**	298
Interest - net *(note 5)*	**27**	10
Foreign exchange *(note 5)*	**(5)**	7
Other - net	**3**	3
	2,328	1,519
Earnings before income taxes	**776**	575
Income taxes		
Current	**204**	67
Future	**48**	124
	252	191
Net earnings	**$ 524**	$ 384
Earnings per share *(note 8)*		
Basic	**$ 1.24**	$ 0.91
Diluted	**$ 1.24**	$ 0.91
Weighted average number of common shares outstanding *(millions) (note 8)*		
Basic	**424.1**	423.8
Diluted	**424.1**	423.8

Consolidated Statements of Retained Earnings

(millions of dollars) (unaudited)	Three months ended March 31 **2006**	2005
Beginning of period	**$ 3,997**	$ 2,694
Net earnings	**524**	384
Dividends on common shares	**(106)**	(51)
End of period	**$ 4,415**	$ 3,027

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

(millions of dollars) (unaudited)	Three months ended March 31 **2006**	2005
Operating activities		
Net earnings	**$ 524**	$ 384
Items not affecting cash		
Accretion *(note 4)*	**9**	8
Depletion, depreciation and amortization	**379**	298
Future income taxes	**48**	124
Foreign exchange	**(1)**	7
Other	**8**	(5)
Settlement of asset retirement obligations	**(8)**	(5)
Change in non-cash working capital *(note 9)*	**165**	(82)
Cash flow - operating activities	**1,124**	729
Financing activities		
Bank operating loans financing - net	**62**	33
Long-term debt issue	**975**	1,422
Long-term debt repayment	**(1,022)**	(1,243)
Proceeds from exercise of stock options	**1**	1
Dividends on common shares	**(106)**	(51)
Change in non-cash working capital *(note 9)*	**(419)**	(223)
Cash flow - financing activities	**(509)**	(61)
Available for investing	**615**	668
Investing activities		
Capital expenditures	**(860)**	(691)
Asset sales	**32**	43
Other	**(1)**	-
Change in non-cash working capital *(note 9)*	**(31)**	(18)
Cash flow - investing activities	**(860)**	(666)
Increase (decrease) in cash and cash equivalents	**(245)**	2
Cash and cash equivalents at beginning of period	**249**	7
Cash and cash equivalents at end of period	**$ 4**	$ 9

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

Three months ended March 31, 2006 *(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 [(1)]		Total	
			Upgrading		Infrastructure and Marketing							
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005	**2006**	2005
Three months ended March 31												
Sales and operating revenues, net of royalties	**$ 1,287**	$ 888	**$ 405**	$ 353	**$ 2,464**	$ 1,452	**$ 546**	$ 437	**$ (1,598)**	$ (1,036)	**$ 3,104**	$ 2,094
Costs and expenses												
Operating, cost of sales, selling and general	**311**	240	**262**	195	**2,372**	1,353	**511**	399	**(1,529)**	(983)	**1,927**	1,204
Depletion, depreciation and amortization	**351**	273	**6**	5	**6**	5	**10**	9	**6**	6	**379**	298
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**27**	10	**27**	10
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(5)**	7	**(5)**	7
	662	513	**268**	200	**2,378**	1,358	**521**	408	**(1,501)**	(960)	**2,328**	1,519
Earnings (loss) before income taxes	**625**	375	**137**	153	**86**	94	**25**	29	**(97)**	(76)	**776**	575
Current income taxes	**143**	53	**24**	11	**19**	(7)	**9**	(1)	**9**	11	**204**	67
Future income taxes	**70**	83	**20**	35	**10**	39	**-**	12	**(52)**	(45)	**48**	124
Net earnings (loss)	**$ 412**	$ 239	**$ 93**	$ 107	**$ 57**	$ 62	**$ 16**	$ 18	**$ (54)**	$ (42)	**$ 524**	$ 384
Capital employed - As at March 31	**$ 8,937**	$ 7,636	**$ 547**	$ 509	**$ 275**	$ 602	**$ 521**	$ 372	**$ (439)**	$ (211)	**$ 9,841**	$ 8,908
Capital expenditures - Three months ended March 31	**$ 757**	$ 662	**$ 37**	$ 17	**$ 1**	$ 6	**$ 64**	$ 5	**$ 6**	$ 4	**$ 865**	$ 694
Total assets - As at March 31	**$ 13,237**	$ 11,286	**$ 858**	$ 714	**$ 763**	$ 925	**$ 883**	$ 647	**$ 118**	$ 118	**$15,859**	$ 13,690

[(1)] *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, 2005, 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, 2005.

Note 3 Change in Accounting Policies

Non-monetary Transactions

Effective January 1, 2006, the Company adopted the revised recommendations of the Canadian Institute of Chartered Accountants section 3831, "Non-monetary Transactions" which replaced section 3830 of the same name. The new recommendations require that all non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business. The guidance was effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006.

Note 4 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Three months ended March 31	
	2006	2005
Asset retirement obligations at beginning of period	**$ 557**	$ 509
Liabilities incurred	**6**	3
Liabilities disposed	**-**	(7)
Liabilities settled	**(8)**	(5)
Accretion	**9**	8
Asset retirement obligations at end of period	**$ 564**	$ 508

At March 31, 2006, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.4 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 2006**	Dec. 31 2005	**March 31 2006**	Dec. 31 2005
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Bilateral credit facilities	2008	**$ 50**	$ -	**$ -**	$ -
7.125% notes	2006	**175**	175	**150**	150
6.25% notes	2012	**467**	467	**400**	400
7.55% debentures	2016	**233**	233	**200**	200
6.15% notes	2019	**350**	350	**300**	300
8.45% senior secured bonds	2006	**-**	99	**-**	85
Medium-term notes	2007-9	**300**	300	**-**	-
8.90% capital securities	2028	**263**	262	**225**	225
Total long-term debt		**1,838**	1,886	**$ 1,275**	$ 1,360
Amount due within one year		**(275)**	(274)		
		$ 1,563	$ 1,612		

Interest - net consisted of:

	Three months ended March 31	
	2006	2005
Long-term debt	**$ 37**	$ 34
Short-term debt	**1**	1
	38	35
Amount capitalized	**(11)**	(24)
	27	11
Interest income	**-**	(1)
	$ 27	$ 10

Foreign exchange consisted of:

	Three months ended March 31	
	2006	2005
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ (1)**	$ 9
Cross currency swaps	**(1)**	(2)
Other gains	**(3)**	-
	$ (5)	$ 7

Note 6 Commitments and Contingencies

The Company has no material litigation other than 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			
	2006		2005	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of period	424,125,078	$ 3,523	423,736,414	$ 3,506
Exercised - options and warrants	45,500	3	113,812	3
Balance at March 31	**424,170,578**	**$ 3,526**	423,850,226	$ 3,509

Stock Options

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

	Three months ended March 31			
	2006		2005	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	7,285	$ 25.81	9,964	$ 22.61
Granted	340	$ 66.34	60	$ 33.72
Exercised for common shares	(46)	$ 20.21	(84)	$ 12.44
Surrendered for cash	(412)	$ 22.19	(314)	$ 13.43
Forfeited	(73)	$ 29.52	(93)	$ 24.99
Outstanding, March 31	**7,094**	**$ 27.96**	9,533	$ 23.05
Options exercisable at March 31	**1,152**	**$ 22.94**	1,127	$ 13.31

	March 31, 2006							
	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	
$13.95 - $14.99	108	$	14.56	2	65	$	14.40
$15.00 - $22.99	197	$	19.55	2	118	$	18.59
$23.00 - $23.99	5,595	$	23.83	3	941	$	23.83
$24.00 - $39.99	374	$	32.10	4	28	$	31.47
$40.00 - $67.63	820	$	58.08	5	-	$	-
	7,094	**$**	**27.96**	**3**	**1,152**	**$**	**22.94**

Note 8 Earnings per Common Share

	Three months ended March 31	
	2006	2005
Net earnings	**$ 524**	$ 384
Weighted average number of common shares outstanding *(millions)*		
Basic	**424.1**	423.8
Diluted	**424.1**	423.8
Earnings per share		
Basic	**$ 1.24**	$ 0.91
Diluted	**$ 1.24**	$ 0.91

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

	Three months ended March 31	
	2006	2005
a) Change in non-cash working capital was as follows:		
Decrease (increase) in non-cash working capital		
Accounts receivable	**$ 104**	$ (45)
Inventories	**32**	(54)
Prepaid expenses	**4**	(11)
Accounts payable and accrued liabilities	**(425)**	(213)
Change in non-cash working capital	**(285)**	(323)
Relating to:		
Financing activities	**(419)**	(223)
Investing activities	**(31)**	(18)
Operating activities	**$ 165**	$ (82)
b) Other cash flow information:		
Cash taxes paid	**$ 129**	$ 83
Cash interest paid	**$ 32**	$ 30

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended March 31	
	2006	2005
Employer current service cost	**$ 4**	$ 4
Interest cost	**2**	2
Expected return on plan assets	**(1)**	(2)
Amortization of net actuarial losses	**-**	1
	$ 5	$ 5

Note 11 Financial Instruments and Risk Management

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

	March 31 2006	Dec. 31 2005
Commodity price risk management		
Power consumption	**$ (1)**	$ -
Interest rate risk management		
Interest rate swaps	**5**	7
Foreign currency risk management		
Foreign exchange contracts	**(33)**	(32)

Commodity Price Risk Management

Power Consumption

At March 31, 2006, the Company had hedged power consumption as follows:

	Notional Volumes *(MW)*	Term	Price
Fixed price purchase	19.0	Apr. to Aug. 2006	$62.50/MWh
	19.0	Apr. to Sept. 2006	$63.00/MWh
	38.0	Oct. to Dec. 2006	$62.95/MWh

The impact of the hedge program during the first quarter of 2006 was a loss of $0.3 million (first quarter of 2005 - loss of $0.3 million).

Natural Gas Contracts

At March 31, 2006, 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	37,172	$ 25
Physical sale contracts	(37,172)	$ (18)

Interest Rate Risk Management

During the first quarter of 2006, the Company realized a gain of $1 million (first quarter of 2005 - gain of $5 million) from interest rate risk management activities.

Foreign Currency Risk Management

During the first quarter of 2006, the Company realized a $2 million gain (first quarter of 2005 - loss of $3 million) from all foreign currency risk management activities.

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, 2006, $350 million (December 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
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
feedstock	Raw materials which are processed into petroleum products
nameplate capacity	The maximum continuous rated output of a plant based on its design

(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 Tuesday, April 18, 2006 at 4:15 p.m. Eastern time to discuss Husky's first quarter results which will be released after market close on Monday April 17, 2006. To participate please dial 1-800-377-5794 beginning at 4:15 p.m. Eastern time. Mr. John C.S. Lau, President & Chief Executive Officer, and other officers will be participating in the call.

Those 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 5:30 p.m. (EST), then dialing reservation number 21286513. The Postview will be available until Thursday, May 18, 2006.

Media are invited to listen to the conference call by dialing 1-800-377-5794 beginning at 4:15 p.m. Eastern time.

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For further information, please contact:

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