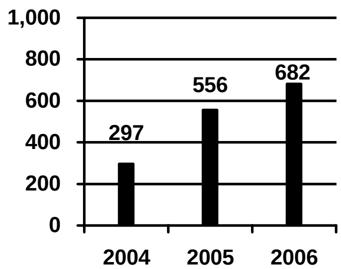
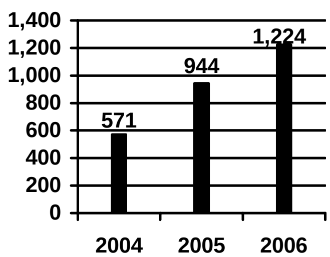
HUSKY ENERGY ANNOUNCES 2006 THIRD QUARTER RESULTS

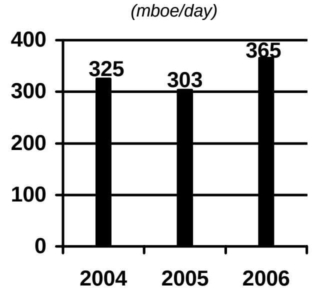
Third Quarter Net Earnings
($ millions)



Third Quarter Cash Flow from Operations
($ millions)



Third Quarter Total Production
(mboe/day)



Calgary, Alberta – Husky Energy Inc. reported net earnings of $682 million or $1.61 per share (diluted) in the third quarter of 2006, up 23 percent from $556 million or $1.31 per share (diluted) in the third quarter of 2005. Cash flow from operations in the third quarter was $1.2 billion or $2.88 per share (diluted), a 30 percent increase compared with $944 million or $2.23 per share (diluted) for the same period in 2005. Sales and operating revenues, net of royalties, were $3.4 billion in the third quarter of 2006, compared with $2.6 billion in the third quarter of 2005.

"Husky achieved solid financial and operational results for the third quarter," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "The results demonstrate Husky's ability to effectively execute our strategy while maintaining an emphasis on financial discipline and integration, building a quality asset base for future growth."

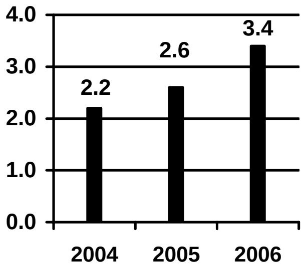
Production in the third quarter of 2006 was 364,700 barrels of oil equivalent per day, up 20 percent compared with 303,200 barrels of oil equivalent per day in the third quarter of 2005. Total crude oil and natural gas liquids production was 253,200 barrels per day, compared with 190,000 barrels per day in the third quarter of 2005. Natural gas production was 669.1 million cubic feet per day, compared with 679.2 million cubic feet per day in the third quarter of 2005.

In Western Canada, Husky has successfully implemented an enhanced oil recovery project to extend the production life of the Taber South Mannville B Pool. The $70 million project, which is the first of its kind in Canada, has been awarded with funding support up to $10 million from the Alberta Government's Innovative Energy Technologies Program.

The Tucker Oil Sands Project, located 30 kilometres northwest of Cold Lake, Alberta, was completed on-schedule and under its $500 million budget. First steam was achieved on August 20, 2006 with first oil anticipated in November 2006. During the 35-year life of the project, Husky expects peak production of more than 30,000 barrels per day.

The Sunrise Oil Sands Project continues with front-end engineering design work targeted to be complete by the third quarter of 2007. The Company continues to evaluate alternatives for the downstream portion of the project.

Third Quarter Sales and Operating Revenues
($ billions)



Development planning continues for the Saleski and Caribou Oil Sands Projects. At Saleski, appropriate bitumen recovery processes are being evaluated.

During the third quarter, Husky successfully acquired 46,080 acres of oil sands leases through Alberta land auctions, which added to our holdings in the Saleski area. The acquired leases are estimated to contain 3.3 billion barrels of original bitumen in place within the Grosmont and Nisku carbonates. Husky's holdings at Saleski now total 239,200 acres with original bitumen in place estimated at 24.1 billion barrels.

At the White Rose oil field, gross production in the third quarter averaged 104,700 barrels per day, with 75,900 barrels per day net to Husky. A sixth production well, which is scheduled to come on-stream at the end of 2006, is expected to increase reservoir production capacity to 125,000 barrels of oil per day. Throughput tests were conducted on the White Rose FPSO and plans are being put in place to debottleneck the facility to around 140,000 barrels of oil per day during the scheduled turnaround next summer.

The Terra Nova FPSO returned to the oil field in late September after undergoing repairs and modifications to improve operational efficiency. Hook-up and start-up will proceed during October and oil production is expected to resume at the end of the month.

In the Jeanne d'Arc Basin, approximately 900 square kilometres of 3-D seismic was completed during the third quarter. This program was shot in the vicinity of the White Rose and Terra Nova oil fields to evaluate future exploration opportunities.

Internationally, Husky signed three petroleum contracts with CNOOC (China National Offshore Oil Corporation) for exploration blocks in the South China Sea. The three exploration blocks cover approximately 16,871 square kilometres. Blocks 35/18 and 50/14 are located in the Ying Ge Hai Basin, west of Hainan Island and cover a combined 7,606 square kilometres.

Block 29/06, located in the Pearl Mouth Basin, is adjacent to Block 29/26, which contains the Liwan 3-1-1 discovery. This discovery contains an estimated resource of four to six trillion cubic feet of natural gas. In the third quarter, Husky successfully sidetracked and cored the Liwan 3-1-1 well confirming the pay zones encountered in the original well. Husky also completed a 400 square kilometre 3-D seismic program over the Liwan discovery in September. Further drilling is planned to delineate the discovery.

Regarding midstream and refined products, Husky announced expansion of its mainline crude oil pipeline between Lloydminster and its terminal at Hardisty, Alberta. The expansion will accommodate increased production from the Tucker Oil Sands Project, and shipments from third parties.

Construction at the Lloydminster Ethanol Plant adjacent to the Upgrader was completed. Husky's facility is the largest plant of its kind in Western Canada and will produce annually 130 million litres of ethanol and 134,000 tonnes of Distillers Dried Grain with Solubles, a high protein feed supplement. Construction of a second ethanol plant at Minnedosa, Manitoba is approximately 37 percent complete and should become operational in mid-2007.

At the Prince George Refinery, production throughput increased from 9,600 barrels per day in the third quarter of 2005 to 11,600 barrels per day in the same period of 2006. This increase marks the successful start-up of the low sulphur diesel facilities and completion of the expansion project.

Standard and Poor's Rating Services raised the Company's long-term corporate credit and senior unsecured debt ratings to BBB+ with a stable outlook. Standard and Poor's based its decision on Husky's successful execution and completion of the White Rose project and the Company's very good internal growth prospects, competitive full cycle cost profile and consistently moderate financial risk profile.

The Company has continued to improve its financial strength and flexibility. Debt to capital employed was reduced to 15.6 percent at September 30, 2006 compared with 20.1 percent at December 31, 2005. Debt to cash flow from operations decreased to 0.4 times at September 30, 2006 compared with 0.5 times at December 31, 2005.

Returns on equity and average capital employed have strengthened. Return on equity and return on average capital employed reached 34.2 percent and 28.7 percent respectively for the period ended September 30, 2006.

Husky’s net earnings for the first nine months of 2006 were $2.2 billion or $5.15 per share (diluted), compared with $1.3 billion or $3.15 per share (diluted) for the same period in 2005. Cash flow from operations for the first nine months of 2006 was $3.3 billion or $7.76 per share (diluted), compared with $2.6 billion or $6.11 per share (diluted) for the same period in 2005.

Production in the first nine months of 2006 was 354,100 barrels of oil equivalent per day, compared with 310,500 barrels of oil equivalent per day in the same period in 2005. Total crude oil and natural gas liquids production was 241,500 barrels per day, compared with 196,900 barrels per day during the first nine months of 2005. Natural gas production was 675.7 million cubic feet per day, compared with 681.6 million cubic feet per day in the first nine months of 2005.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") **October 19, 2006**

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. Readers are encouraged to refer to Husky's MD&A and Consolidated Financial Statements and 2005 Annual Information Form 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, at www.sec.gov and at www.huskyenergy.ca.

Forward-looking Statements

This MD&A contains forward-looking statements. These statements are based on estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. The reader is advised to refer to Section 14.0 "Forward-looking Statements or Information" for additional information.

Use of Pronouns and Other Terms Denoting Husky

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

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended September 30, 2006 are compared with results for the three months ended September 30, 2005 and results for the nine months ended September 30, 2006 are compared with results for the nine months ended September 30, 2005. Discussions with respect to Husky's financial position as at September 30, 2006 are compared with its financial position at December 31, 2005.

Additional Reader Guidance

- The Consolidated Financial Statements and comparative financial information included 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.

1.0 SUMMARY OF QUARTERLY RESULTS

Husky's net earnings for the third quarter of 2006 were $682 million, up $126 million compared with the third quarter of 2005.

Higher earnings in the third quarter of 2006 were primarily due to higher crude oil production from the White Rose oil field, higher crude oil prices and higher light refined product margins. These positive factors were partially offset by lower natural gas prices and sales volume, suspension of production at Terra Nova and production declines at Wenchang.

Financial Summary

(millions of dollars, except per share amounts and ratios)	**Sept. 30 2006**	June 30 2006	March 31 2006	Dec. 31 2005	Sept. 30 2005	June 30 2005	March 31 2005	Dec. 31 2004
Sales and operating revenues, net of royalties	**$ 3,436**	$ 3,040	$ 3,104	$ 3,207	$ 2,594	$ 2,350	$ 2,094	$ 2,018
Segmented earnings								
Upstream	**$ 608**	$ 822	$ 412	$ 533	$ 445	$ 307	$ 239	$ 112
Midstream	**87**	140	150	135	61	130	169	77
Refined Products	**28**	52	16	17	27	20	18	(3)
Corporate and eliminations	**(41)**	(36)	(54)	(16)	23	(63)	(42)	39
Net earnings	**$ 682**	$ 978	$ 524	$ 669	$ 556	$ 394	$ 384	$ 225
Per share - Basic	**$ 1.61**	$ 2.31	$ 1.24	$ 1.58	$ 1.31	$ 0.93	$ 0.91	$ 0.53
- Diluted	**1.61**	2.31	1.24	1.58	1.31	0.93	0.91	0.53
Cash flow from operations	**1,224**	1,103	967	1,197	944	828	816	469
Per share - Basic	**2.88**	2.60	2.28	2.82	2.23	1.95	1.93	1.11
- Diluted	**2.88**	2.60	2.28	2.82	2.23	1.95	1.93	1.11
Dividends per common share	**0.50**	0.25	0.25	0.25	0.14	0.14	0.12	0.12
Special dividend per common share	**-**	-	-	1.00	-	-	-	0.54
Total assets	**17,389**	16,405	15,859	15,797	14,712	14,058	13,690	13,240
Total long-term debt including current portion	**1,722**	1,722	1,838	1,886	1,896	2,192	2,290	2,103
Return on equity (1) *(percent)*	**34.2**	34.8	29.6	29.2	22.9	20.2	18.3	17.0
Return on average capital employed (1) *(percent)*	**28.7**	28.2	23.2	22.8	17.9	15.3	13.9	13.0

(1) *Calculated for the 12 months ended for the dates shown.*

Western Canada crude oil production rose marginally in the third quarter of 2006 compared with the second quarter of 2006 as a result of higher production of heavy crude oil. Natural gas sales volume decreased marginally from the second quarter of 2006 to the third quarter of 2006.

In the third quarter of 2006, 128 gross (95 net) exploration wells were drilled in the Western Canada Sedimentary Basin ("WCSB") resulting in 41 gross (40 net) oil wells and 82 gross (50 net) gas wells.

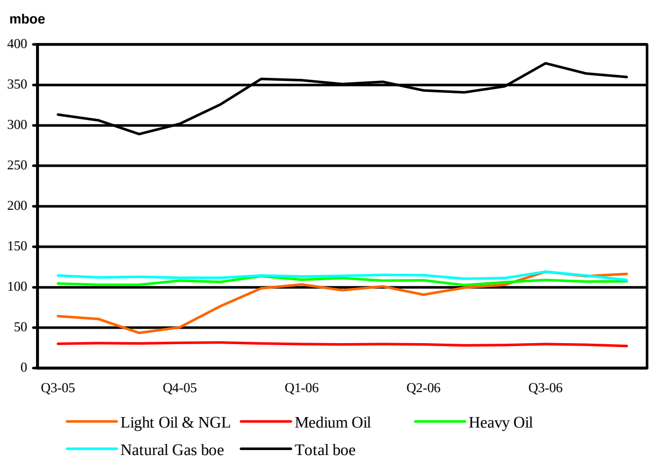
At White Rose the fifth production well came on-stream on June 25 raising production capacity to 110-115 mbbls/day (80-83 mbbls/day Husky's share).

At Terra Nova, production operations were suspended on May 7, 2006 and the FPSO was sent to dry dock in the Netherlands for repairs, maintenance and modifications. The FPSO returned to the field on September 25 and was connected to the spider buoy on October 1. Terra Nova is expected to commence production at the end of the month.

Wenchang oil field production declined marginally in the third quarter of 2006 compared with the second quarter of 2006 reflecting natural reservoir decline combined with downtime for weather and liquefied petroleum gas facilities installation.

Daily Gross Production		Three months ended				
		Sept. 30 2006	June 30 2006	March 31 2006	Dec. 31 2005	Sept. 30 2005
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**30.2**	29.8	31.3	30.1	31.8
Medium crude oil		**28.1**	28.5	29.4	31.0	30.3
Heavy crude oil		**107.9**	105.6	109.5	109.5	103.3
		166.2	163.9	170.2	170.6	165.4
East Coast Canada						
White Rose - light crude oil		**75.9**	53.0	46.4	19.0	-
Terra Nova - light crude oil		-	2.8	9.3	12.2	10.2
China						
Wenchang - light crude oil		**11.1**	12.1	13.5	14.1	14.4
		253.2	231.8	239.4	215.9	190.0
Natural gas	*(mmcf/day)*	**669.1**	672.8	685.4	675.3	679.2
Total	*(mboe/day)*	**364.7**	344.0	353.6	328.5	303.2

Production



During the third quarter of 2006 White Rose was further developed and Husky's share averaged 75.9 mbbls/day. This increase in production was partially offset by the Terra Nova oil field, shut-in for repairs and unscheduled maintenance and modifications.

2.0 STRATEGIC PLANS AND CAPABILITIES

The following projects are at various stages of development and, upon completion, are expected to provide for sustained growth to the Company.

Upstream

- East Coast Exploration and Development
- Oil Sands Development
- Mackenzie River Valley Exploration
- China and Indonesia Exploration and Development

Midstream

- Upgrader Expansion

Refined Products

- Refinery Modifications
- Ethanol Plant Construction

2.1 UPSTREAM

Gross Production		Nine months ended Sept. 30	Full Year Forecast	Nine months ended Sept. 30	Year ended Dec. 31
		2006	2006	2005	2005
Crude oil & NGL	*(mbbls/day)*				
Light crude oil & NGL		**105.1**	103 - 116	61.0	64.6
Medium crude oil		**28.7**	29 - 32	31.1	31.1
Heavy crude oil		**107.7**	115 - 120	104.8	106.0
		241.5	247 - 268	196.9	201.7
Natural gas	*(mmcf/day)*	**675.7**	680 - 730	681.6	680.0
Total barrels of oil equivalent	*(mboe/day)*	**354.1**	360 - 390	310.5	315.0

Our assets in the WCSB currently provide the majority of the funding required to finance our strategic plans including exploitation activities, which involve increased drilling of infill and step-out wells, and the installation of various types of enhanced recovery techniques, including thermal recovery of heavy oil and emerging technologies such as alkaline surfactant polymer floods.

Exploration for significant resources in the WCSB is concentrated in specific areas of the foothills, deep basin and northern plains of Alberta and British Columbia. These natural gas prone areas involve assiduous exploration processes that target multi-zone potential, natural gas reserves from unconventional sources and optimization of existing infrastructure through extension of established producing areas.

White Rose Oil Field

White Rose now has five producing wells with a productive capacity of 110-115 mbbls/day (80-83 mbbls/day Husky's share). In the third quarter we performed a detailed technical and operational review of the field, including a performance test of the production processing facilities on board the *SeaRose FPSO*. This test demonstrated that the processing facilities are able to support an annual average of 125 mbbls/day (90.6 mbbls/day Husky's share). Reservoir capacity is expected to be higher than 125 mbbls/day with the completion of a sixth production well by the end of 2006.

East Coast Canada Exploration and Delineation

In the third quarter of 2006 we drilled the West Bonne Bay F-12, a delineation well in the Significant Discovery Licence 1040, which is adjacent to the Terra Nova field. Preliminary results indicate hydrocarbons in the Upper Hibernia Reservoir. Well results are being evaluated.

The 3-D seismic program covering a total of 896 square kilometers was shot on Exploration Licence 1067, which is northwest of White Rose, and near Fortune, which is located on Significant Discovery Licence 1011, southwest of White Rose. Planning is well underway for our 2007 exploration and delineation drilling program which currently includes three locations in the Jeanne d'Arc Basin.

Tucker Oil Sands Project

During the third quarter of 2006 construction was completed at the Tucker steam-assisted gravity drainage in-situ oil sands project and the steam generation facilities were commissioned. Steam injection into two of three pads commenced on August 20, 2006. Steam injection at the remaining pad is expected to commence by the end of October. First bitumen production is expected to be on-schedule in November 2006.

Sunrise Oil Sands Project

The conceptual design for the upstream development at the Sunrise Oil Sands Project progressed well. This aspect of the project includes options for field development, oil treatment and steam generation and is approximately 55 percent complete. The entire front-end engineering design ("FEED") for Sunrise is scheduled to be complete by the third quarter of 2007.

During the third quarter, we drilled five source water evaluation wells and we plan to drill 10 more this winter. We are currently completing seismic studies and have determined 29 stratigraphic well locations for the winter drilling season. Collaboration with various industry participants continued on regional infrastructure issues, including an access highway and airport.

Caribou and Saleski

During the third quarter of 2006 we participated in two land sales in the Saleski area and acquired leases totalling 46,080 acres. These leases are currently estimated to hold approximately 3.3 billion barrels of bitumen in place within the Grosmont and Nisku carbonates. We now hold leases totalling 239,200 acres in the Saleski area, which are estimated to contain 24.1 billion barrels of bitumen in place.

In addition, conceptual development planning continued with water source and disposal well studies for both Saleski and Caribou and determination of an appropriate bitumen recovery process for Saleski. At Caribou we completed selection of 44 stratigraphic well locations to be drilled during the winter drilling season.

Northwest Territories Exploration

A seismic program was shot during the third quarter that included our newly acquired Exploration Licence 441, which is contiguous with the eastern boundary of our Exploration Licence 397 containing the Stewart D-57 natural gas discovery. Based on the timing of this seismic program and subsequent analytical work we, with our partners, have decided to defer further exploration drilling until the winter of 2007/2008. This will allow for full incorporation of new seismic data into the prospect mapping that is currently underway.

China Exploration

During the third quarter of 2006 we acquired three exploration blocks offshore China that in aggregate total 16,871 square kilometres. Block 29/06 is 9,265 square kilometres and located in the Pearl River Mouth Basin adjacent to Block 29/26, the location of the Liwan natural gas discovery. Block 35/18 is 4,469 square kilometres and Block 50/14 is 3,137 square kilometers; both are located in the Ying Ge Hai Basin west of Hainan Island. Under the terms of the agreement we will pay 100 percent of the costs to drill two wells on Block 29/06 and one well on each of the other two blocks. The China National Offshore Oil Corporation has the option to participate in up to 51 percent of any future development.

At the Liwan natural gas discovery a side track well confirmed the pay zones in the original well. We also completed shooting 400 square kilometres of 3-D seismic over the Liwan discovery and it is currently being analyzed in preparation for delineation drilling. We are currently seeking tenders to drill an exploration well on Block 04/35 in the East China Sea and expect a spud date in the first half of 2007.

Indonesia Natural Gas Development

At Madura, negotiations for a natural gas sales agreement are continuing. Development of the Madura natural gas field is contingent on receiving government approval. In September Husky signed the Production Sharing Contract for the East Bawean II Block.

2.2 MIDSTREAM

In August 2006 we announced the expansion of the Lloydminster to Hardisty section of our pipeline. The expansion, which will run from Wainwright and Battle River, Alberta to Lloydminster will involve the installation of 24 inch (610 mm) pipelines and associated facilities and will be done in two phases. Completion of both phases is expected by the fourth quarter of 2007.

Lloydminster Upgrader

The FEED for the expansion of the Lloydminster Upgrader progressed to approximately 16 percent of completion. Completion of the FEED is scheduled for the third quarter of 2007. During the quarter we commenced the environmental phase of the regulatory approval process with the Government of Saskatchewan. The expansion envisions increasing throughput capacity from 80 mbbls/day to 150 mbbls/day.

2.3 REFINED PRODUCTS

Lloydminster and Minnedosa Ethanol Plants

To meet the increasing demand for ethanol blended gasoline, we are progressing with 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 throughput capacity of 130 million litres of ethanol per year. During the third quarter of 2006 the Lloydminster Ethanol Plant was completed and we are currently in start-up mode. At Minnedosa, Manitoba construction of that ethanol plant is approximately 37 percent complete and is scheduled for completion in the third 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				
		Sept. 30 2006	June 30 2006	March 31 2006	Dec. 31 2005	Sept. 30 2005
WTI crude oil [(1)]	*(U.S. $/bbl)*	**70.48**	70.70	63.48	60.02	63.10
Brent crude oil [(2)]	*(U.S. $/bbl)*	**69.49**	69.62	61.75	56.90	61.54
Canadian par light crude 0.3% sulphur	*($/bbl)*	**79.65**	78.97	69.40	71.65	77.04
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**49.61**	48.65	26.25	29.60	44.13
NYMEX natural gas [(1)]	*(U.S. $/mmbtu)*	**6.58**	6.79	8.98	12.97	8.49
NIT natural gas	*($/GJ)*	**5.72**	5.95	8.79	11.08	7.75
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**19.24**	17.99	29.20	24.24	18.90
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.892**	0.891	0.866	0.852	0.833

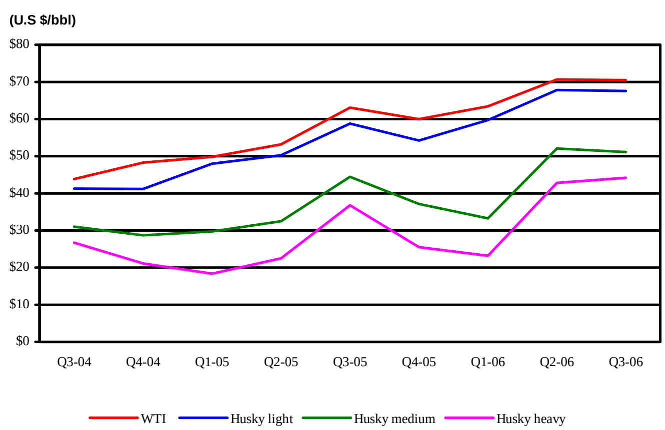
[(1)] *Prices quoted are near-month contract prices for settlement during the next month.*
[(2)] *Dated Brent prices which are dated less than 15 days prior to loading for delivery.*

3.1 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. 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 any given time.

Crude Oil

WTI and Husky Average Crude Oil Prices



The price of West Texas Intermediate crude oil rose through the first six months of 2006, and declined marginally during the third quarter. Our light and medium crude oil prices followed suit while heavy crude oil prices rose marginally, narrowing the light/heavy crude price differential.

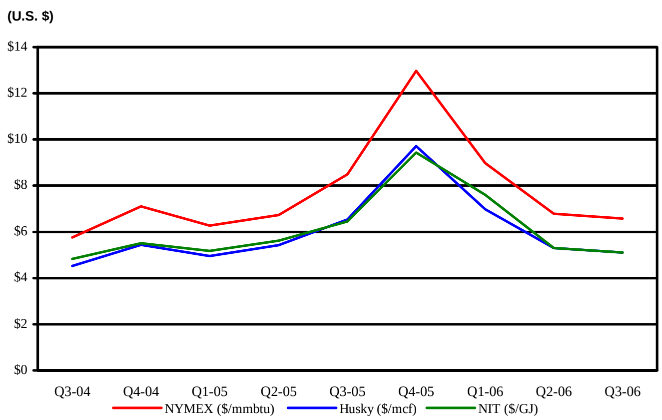
WTI, the benchmark crude price, has escalated throughout the period reported with some fluctuations, closely followed by Husky's light crude prices.

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.

Concerns about global crude oil supply seem to have been abated, in part due to no hurricane damage to producing facilities in the Gulf of Mexico this year, Iran's participation in continued negotiation in respect of the uranium enrichment issue, the absence of Nigeria's past production disruptions and the stabilization of Iraq production at levels not achieved since fall of 2004. All of these and other issues that could affect the global supply/demand balance are subject to change at any time. As a result, there can be no certainty concerning the foreseeable future of crude oil prices.

Natural Gas

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



Both U.S. and Canadian benchmark natural gas prices decreased in 2006. Husky's natural gas prices, which are dominated by floating prices, followed suit.

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 on NYMEX have declined to levels not seen since September 2004 with near-month contracts trading around the U.S. $5.00/mmbtu mark. Natural gas in storage in the United States at the end of September was approximately 12 percent above five year averages.

Other Business Environment Risks

Please refer to our 2005 MD&A for a discussion about other business environment risks.

3.2 SENSITIVITY ANALYSIS

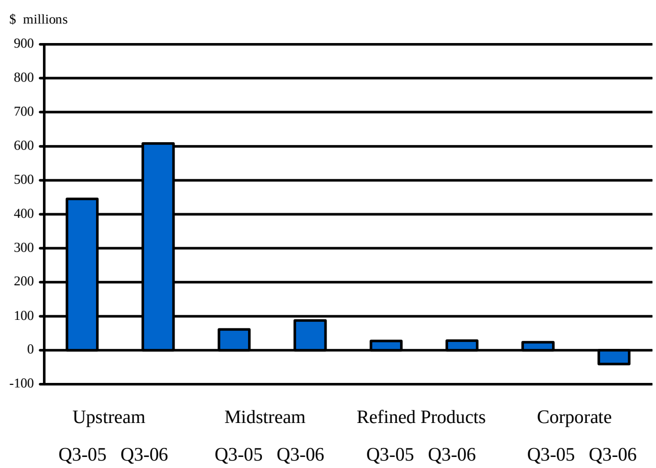
The following table indicates the relative annual effect of changes in certain key variables on our pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the third quarter of 2006. Each separate item in the sensitivity analysis shows the effect 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	2006 Third 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	70.48	*U.S. $1.00/bbl*	92	0.22	61	0.14
NYMEX benchmark natural gas price [1]	6.58	*U.S. $0.20/mmbtu*	38	0.09	25	0.06
WTI/Lloyd crude blend differential [2]	19.24	*U.S. $1.00/bbl*	(28)	(0.06)	(18)	(0.04)
Exchange rate (U.S. $ per Cdn $) [3]	0.89	*U.S. $0.01*	(75)	(0.18)	(49)	(0.11)
Refined Products						
Light oil margins	0.05	*Cdn $0.005/litre*	17	0.04	11	0.03
Asphalt margins	4.97	*Cdn $1.00/bbl*	11	0.03	7	0.02
Consolidated						
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	0.90 [4]	*U.S. $0.01*			8	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 September 30, 2006.*
[5] *Based on September 30, 2006 common shares outstanding of 424.3 million.*

4.0 RESULTS OF OPERATIONS

Quarterly Segmented Earnings



Husky's profitability is largely dependant on Upstream operations, partially supported by upgrading results during times when light/heavy crude oil differentials are wider.

4.1 UPSTREAM

Third Quarter

Upstream earnings were $163 million higher in the third quarter of 2006 than in the third quarter of 2005 as a result of the following factors:

- higher sales volume of light crude oil from White Rose and heavy crude oil from the Lloydminster area;
- higher light, medium and heavy crude oil prices; and
- lower natural gas royalties.

Partially offset by:

- lower natural gas prices;
- lower sales volume of light crude oil from Terra Nova and lower sales volume of medium crude oil and natural gas;
- higher unit operating costs;
- higher unit depletion, depreciation and amortization; and
- higher income taxes.

Nine Months

The factors that affected results for the third quarter also affected variances in results for the nine months ended September 30, 2006.

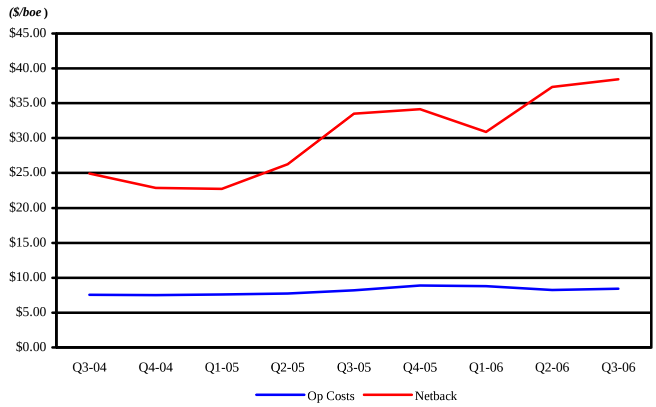
Upstream Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2006**	2005	**2006**	2005
Gross revenues	**$ 1,816**	$ 1,422	**$ 4,967**	$ 3,616
Royalties	**216**	246	**629**	576
Net revenues	**1,600**	1,176	**4,338**	3,040
Operating and administration expenses	**329**	262	**948**	751
Depletion, depreciation and amortization	**382**	280	**1,087**	831
Income taxes	**281**	189	**461**	467
Earnings	**$ 608**	$ 445	**$ 1,842**	$ 991

Net Revenue Variance Analysis				
(millions of dollars)	Crude oil & NGL	Natural gas	Other	Total
Three months ended September 30, 2005	$ 771	$ 384	$ 21	$ 1,176
Price changes	118	(129)	-	(11)
Volume changes	405	(7)	-	398
Royalties	(8)	39	-	31
Processing and sulphur	-	-	6	6
Three months ended September 30, 2006	**$ 1,286**	**$ 287**	**$ 27**	**$ 1,600**
Nine months ended September 30, 2005	$ 1,966	$ 1,016	$ 58	$ 3,040
Price changes	631	(54)	-	577
Volume changes	766	(11)	-	755
Royalties	(92)	39	-	(53)
Processing and sulphur	-	-	19	19
Nine months ended September 30, 2006	**$ 3,271**	**$ 990**	**$ 77**	**$ 4,338**

Unit Operating Costs

Unit operating costs were three percent higher in the third quarter of 2006 compared with the same period in 2005 primarily due to higher costs for labour, field services, trucking, shallow natural gas compression, higher natural gas well count and production declines. Unit operating costs were also affected by the Terra Nova turnaround and generally fixed costs associated with production declines. Unit operating costs were partially offset by lower turnaround activity in our Western Canada operations and a higher proportion of lower operating cost production from White Rose. The high level of industry activity has created increased demand and consequently higher prices for oil field materials and services.

Netback and Unit Operating Cost



Higher netbacks due to higher crude oil prices were marginally affected by increases in operating costs.

Unit Depletion, Depreciation and Amortization

Unit depletion, depreciation and amortization expense increased 13 percent in the third quarter of 2006 compared with the same period in 2005. The increase was primarily due to net growth of the capital base in 2006 as a result of increased requirements for production maintenance capital in the WCSB and the start-up of the White Rose oil field, which has a higher ratio of capital to reserves. Also contributing to higher unit depletion are purchases of reserves-in-place, which on a unit cost basis are above the average depletion rate. In addition, higher energy costs, as with operating costs, increased the cost of materials and services embedded in our capital costs.

Average Sales Prices		Three months ended Sept. 30		Nine months ended Sept. 30	
		2006	2005	**2006**	2005
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 74.05**	$ 67.21	**$ 71.74**	$ 60.85
Medium crude oil		**57.35**	53.41	**51.28**	43.34
Heavy crude oil		**49.62**	44.17	**41.45**	31.46
Total average		**61.79**	52.54	**55.81**	42.43
Natural Gas	*($/mcf)*				
Average		**5.69**	7.86	**6.57**	6.90

Effective Royalty Rates	Three months ended Sept. 30		Nine months ended Sept. 30	
Percentage of upstream sales revenues	**2006**	2005	**2006**	2005
Crude oil & NGL	**11%**	16%	**11%**	14%
Natural gas	**18%**	21%	**18%**	20%
Total	**12%**	17%	**13%**	16%

Upstream Revenue Mix	Three months ended Sept. 30		Nine months ended Sept. 30	
Percentage of upstream sales revenues, after royalties	**2006**	2005	**2006**	2005
Crude oil & NGL				
Light crude oil & NGL	**47%**	26%	**44%**	29%
Medium crude oil	**7%**	10%	**8%**	10%
Heavy crude oil	**27%**	30%	**24%**	26%
	81%	66%	**76%**	65%
Natural gas	**19%**	34%	**24%**	35%
	100%	100%	**100%**	100%

Operating Netbacks

Three months ended Sept. 30	WCSB		East Coast		International		Total	
	2006	2005	**2006**	2005	**2006**	2005	**2006**	2005
Light Crude Oil *(per boe)* [(1)]								
Sales Price	**$62.61**	$ 65.25	**$75.78**	$69.62	**$77.07**	$67.98	**$72.58**	$66.80
Royalties	**9.43**	10.02	**0.77**	12.64	**16.80**	6.53	**4.52**	9.56
Operating costs	**7.40**	6.62	**6.03**	5.61	**4.24**	2.56	**6.20**	5.46
	45.78	48.61	**68.98**	51.37	**56.03**	58.89	**61.86**	51.78
Medium Crude Oil *(per boe)* [(1)]								
Sales Price	**56.35**	53.13	**-**	-	**-**	-	**56.35**	53.13
Royalties	**10.02**	9.69	**-**	-	**-**	-	**10.02**	9.69
Operating costs	**12.99**	11.44	**-**	-	**-**	-	**12.99**	11.44
	33.34	32.00	**-**	-	**-**	-	**33.34**	32.00
Heavy Crude Oil *(per boe)* [(1)]								
Sales Price	**49.41**	44.19	**-**	-	**-**	-	**49.41**	44.19
Royalties	**6.71**	6.25	**-**	-	**-**	-	**6.71**	6.25
Operating costs	**10.69**	9.88	**-**	-	**-**	-	**10.69**	9.88
	32.01	28.06	**-**	-	**-**	-	**32.01**	28.06
Total Crude Oil *(per boe)* [(1)]								
Sales Price	**52.94**	49.85	**75.78**	69.62	**77.07**	67.98	**60.79**	52.28
Royalties	**7.77**	7.62	**0.77**	12.64	**16.80**	6.53	**6.09**	7.79
Operating costs	**10.52**	9.57	**6.03**	5.61	**4.24**	2.56	**8.91**	8.84
	34.65	32.66	**68.98**	51.37	**56.03**	58.89	**45.79**	35.65
Natural Gas *(per mcfge)* [(2)]								
Sales Price	**5.99**	7.90	**-**	-	**-**	-	**5.99**	7.90
Royalties	**1.21**	1.78	**-**	-	**-**	-	**1.21**	1.78
Operating costs	**1.23**	1.17	**-**	-	**-**	-	**1.23**	1.17
	3.55	4.95	**-**	-	**-**	-	**3.55**	4.95
Equivalent Unit *(per boe)* [(1)]								
Sales Price	**46.24**	48.86	**75.78**	69.62	**77.07**	67.98	**53.35**	50.49
Royalties	**7.56**	8.82	**0.77**	12.64	**16.80**	6.53	**6.44**	8.83
Operating costs	**9.29**	8.56	**6.03**	5.61	**4.24**	2.56	**8.45**	8.18
	$29.39	$ 31.48	**$68.98**	$ 51.37	**$56.03**	$ 58.89	**$38.46**	$ 33.48

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

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

Operating Netbacks (continued)

Nine months ended Sept. 30	WCSB 2006	WCSB 2005	East Coast 2006	East Coast 2005	International 2006	International 2005	Total 2006	Total 2005
Light Crude Oil *(per boe)* [1]								
Sales Price	**$ 61.86**	$ 57.85	**$ 74.22**	$ 62.23	**$ 76.05**	$ 64.04	**$ 71.01**	$ 60.57
Royalties	**7.37**	7.54	**1.94**	5.61	**12.68**	6.00	**4.73**	6.68
Operating costs	**10.59**	9.16	**6.10**	4.16	**3.46**	2.43	**7.03**	6.20
	43.90	41.15	**66.18**	52.46	**59.91**	55.61	**59.25**	47.69
Medium Crude Oil *(per boe)* [1]								
Sales Price	**50.65**	43.32	-	-	-	-	**50.65**	43.32
Royalties	**9.01**	7.68	-	-	-	-	**9.01**	7.68
Operating costs	**12.34**	10.68	-	-	-	-	**12.34**	10.68
	29.30	24.96	-	-	-	-	**29.30**	24.96
Heavy Crude Oil *(per boe)* [1]								
Sales Price	**41.42**	31.57	-	-	-	-	**41.42**	31.57
Royalties	**5.39**	3.83	-	-	-	-	**5.39**	3.83
Operating costs	**10.74**	9.53	-	-	-	-	**10.74**	9.53
	25.29	18.21	-	-	-	-	**25.29**	18.21
Total Crude Oil *(per boe)* [1]								
Sales Price	**46.57**	38.60	**74.22**	62.23	**76.05**	64.04	**55.19**	42.24
Royalties	**6.37**	5.25	**1.94**	5.61	**12.68**	6.00	**5.55**	5.33
Operating costs	**11.00**	9.68	**6.10**	4.16	**3.46**	2.43	**9.35**	8.74
	29.20	23.67	**66.18**	52.46	**59.91**	55.61	**40.29**	28.17
Natural Gas *(per mcfge)* [2]								
Sales Price	**6.76**	6.97	-	-	-	-	**6.76**	6.97
Royalties	**1.43**	1.56	-	-	-	-	**1.43**	1.56
Operating costs	**1.10**	1.04	-	-	-	-	**1.10**	1.04
	4.23	4.37	-	-	-	-	**4.23**	4.37
Equivalent Unit *(per boe)* [1]								
Sales Price	**44.18**	39.86	**74.22**	62.23	**76.05**	64.04	**50.59**	42.07
Royalties	**7.25**	6.88	**1.94**	5.61	**12.68**	6.00	**6.50**	6.78
Operating costs	**9.25**	8.31	**6.10**	4.16	**3.46**	2.43	**8.50**	7.84
	$ 27.68	$ 24.67	**$ 66.18**	$ 52.46	**$ 59.91**	$ 55.61	**$ 35.59**	$ 27.45

[1] *Includes associated co-products converted to boe.*
[2] *Includes associated co-products converted to mcfge.*

Upstream Capital Expenditures

Capital Expenditures Summary [(1)]	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars)	**2006**	2005	**2006**	2005
Exploration				
Western Canada	**$ 140**	$ 189	**$ 460**	$ 503
East Coast Canada and Frontier	**16**	28	**41**	46
International	**32**	16	**69**	39
	188	233	**570**	588
Development				
Western Canada	**325**	262	**1,082**	856
East Coast Canada	**88**	202	**251**	448
International	**11**	4	**20**	7
	424	468	**1,353**	1,311
	$ 612	$ 701	**$ 1,923**	$ 1,899

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

Upstream capital expenditures totaled $1,923 million, 83 percent of total consolidated capital expenditures during the first nine months of 2006 compared with $1,899 million or 89 percent of the total, during the first nine months of 2005.

Western Canada Wells Drilled [(1) (2)]		Three months ended Sept. 30				Nine months ended Sept. 30			
		2006		2005		**2006**		2005	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**41**	**40**	28	28	**71**	**70**	63	60
	Gas	**82**	**50**	107	43	**278**	**150**	239	136
	Dry	**5**	**5**	7	7	**24**	**22**	26	26
		128	**95**	142	78	**373**	**242**	328	222
Development	Oil	**184**	**163**	154	147	**380**	**334**	285	266
	Gas	**128**	**115**	164	136	**382**	**331**	442	401
	Dry	**9**	**6**	10	8	**20**	**17**	25	23
		321	**284**	328	291	**782**	**682**	752	690
Total		**449**	**379**	470	369	**1,155**	**924**	1,080	912

(1) *Excludes stratigraphic test wells.*
(2) *Includes non-operated wells.*

4.2 MIDSTREAM

Third Quarter

Upgrading earnings in the third quarter of 2006 were $27 million greater than the third quarter of 2005 due to higher sales volume of synthetic crude oil partially offset by higher income taxes.

Nine Months

Upgrading earnings in the nine months of 2006 were $5 million less than 2005 due to reduced differentials and increased operating costs offset by improved sales volume of synthetic crude and lower income taxes.

Upgrading Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2006**	2005	**2006**	2005
Gross margin		**$ 135**	$ 92	**$ 479**	$ 494
Operating costs		**50**	48	**169**	151
Other recoveries		**(1)**	(1)	**(4)**	(4)
Depreciation and amortization		**6**	6	**18**	15
Income taxes		**26**	12	**70**	101
Earnings		**$ 54**	$ 27	**$ 226**	$ 231
Selected operating data:					
Upgrader throughput [1]	*(mbbls/day)*	**73.1**	48.3	**71.0**	63.8
Synthetic crude oil sales	*(mbbls/day)*	**65.7**	43.9	**62.0**	55.9
Upgrading differential	*($/bbl)*	**$ 23.75**	$ 23.53	**$ 27.04**	$ 29.73
Unit margin	*($/bbl)*	**$ 22.38**	$ 23.01	**$ 28.31**	$ 32.41
Unit operating cost [2]	*($/bbl)*	**$ 7.62**	$ 11.04	**$ 8.73**	$ 8.71

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

Upgrading Earnings Variance Analysis

(millions of dollars)	
Three months ended September 30, 2005	$ 27
Volume	46
Margin	(3)
Operating costs - energy related	(1)
Operating costs - non-energy related	(1)
Depreciation and amortization	-
Income taxes	(14)
Three months ended September 30, 2006	**$ 54**
Nine months ended September 30, 2005	$ 231
Volume	54
Margin	(69)
Operating costs - energy related	(5)
Operating costs - non-energy related	(13)
Depreciation and amortization	(3)
Income taxes	31
Nine months ended September 30, 2006	**$ 226**

Third Quarter

Infrastructure and marketing earnings in the third quarter of 2006 decreased marginally compared with 2005 primarily due to inventory adjustments on blended heavy crude oil partially offset by higher heavy crude oil pipeline throughput and margins.

Nine Months

Infrastructure and marketing earnings in the nine months of 2006 increased by $22 million compared with 2005 primarily due to higher crude oil pipeline throughput and margins, higher natural gas marketing income and lower income taxes partially offset by lower income from blended heavy crude oil marketing.

Infrastructure and Marketing Earnings Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)	**2006**	2005	**2006**	2005
Gross margin - pipeline	**$ 26**	$ 21	**$ 80**	$ 68
- other infrastructure and marketing	**32**	38	**152**	154
	58	59	**232**	222
Other expenses	**3**	3	**8**	8
Depreciation and amortization	**6**	5	**17**	16
Income taxes	**16**	17	**56**	69
Earnings	**$ 33**	$ 34	**$ 151**	$ 129
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**457**	418	**479**	472

Midstream Capital Expenditures

Midstream capital expenditures totaled $160 million in the first nine months of 2006; $119 million at the Lloydminster Upgrader, primarily for debottleneck and reliability projects and $41 million on pipelines and infrastructure.

4.3 REFINED PRODUCTS

Third Quarter

Refined Products earnings in the third quarter of 2006 increased by $1 million compared with the third quarter of 2005 due to:

- higher marketing margins for gasoline and distillates.

Partially offset by:

- lower sales volume of refined products.

Nine Months

Refined Products earnings in the nine months of 2006 increased by $31 million compared with 2005 due primarily to higher marketing margins for gasoline and distillates, reduced operating costs and lower income taxes.

Refined Products Earnings Summary		Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except where indicated)		**2006**	2005	**2006**	2005
Gross margin - fuel sales		**$ 42**	$ 41	**$ 121**	$ 94
- ancillary sales		**10**	10	**26**	26
- asphalt sales		**18**	24	**71**	71
		70	75	**218**	191
Operating and other expenses		**18**	19	**53**	55
Depreciation and amortization		**11**	14	**34**	34
Income taxes		**13**	15	**35**	37
Earnings		**$ 28**	$ 27	**$ 96**	$ 65
Selected operating data:					
Number of fuel outlets				**504**	519
Light oil sales	*(million litres/day)*	**9.1**	9.3	**8.7**	8.8
Light oil retail sales per outlet	*(thousand litres/day)*	**13.6**	13.3	**12.8**	12.7
Prince George refinery throughput	*(mbbls/day)* [(1)]	**11.6**	9.6	**8.2**	9.7
Asphalt sales	*(mbbls/day)*	**30.0**	29.9	**24.2**	22.5
Lloydminster refinery throughput	*(mbbls/day)*	**27.9**	25.9	**26.8**	24.9

[(1)] *Prince George throughput decreased in the second quarter of 2006 as a result of a plant shutdown for the commissioning of the low sulphur diesel modifications.*

Refined Products Capital Expenditures

Refined Products capital expenditures totaled $202 million in the first nine months of 2006; $37 million at the Prince George refinery, $82 million at the Lloydminster ethanol plant and $60 million at the Minnedosa ethanol plant.

4.4 CORPORATE

Third Quarter

Corporate expense increased by $64 million in the third quarter of 2006 compared with the third quarter of 2005 due to:

- gain on translation of U.S. denominated debt in 2005;
- gain on settlement of litigation recognized in 2005; and
- lower capitalized interest due to start-up of the White Rose oil field.

Partially offset by:

- lower stock-based compensation expense; and
- lower profit elimination on inventory.

Nine Months

The factors that affected results for the third quarter also affected variances in the results for the nine months ended September 30, 2006.

Corporate Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars) income (expense)	**2006**	2005	**2006**	2005
Intersegment eliminations - net	**$ (2)**	$ (44)	**$ (16)**	$ (53)
Administration expenses	**(7)**	(4)	**(19)**	(15)
Stock-based compensation	**(18)**	(79)	**(103)**	(177)
Accretion	**(1)**	(1)	**(2)**	(2)
Other - net	**(11)**	57	**(19)**	51
Depreciation and amortization	**(6)**	(6)	**(17)**	(17)
Interest on debt	**(28)**	(36)	**(98)**	(108)
Interest capitalized	**9**	36	**30**	91
Interest income	**-**	-	**-**	1
Foreign exchange - realized	**-**	(1)	**19**	4
Foreign exchange - unrealized	**(5)**	64	**13**	32
Income taxes	**28**	37	**81**	111
Earnings (loss)	**$ (41)**	$ 23	**$ (131)**	$ (82)

Foreign Exchange Rates	Three months ended Sept. 30		Nine months ended Sept. 30	
	2006	2005	**2006**	2005
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.897**	U.S.$0.816	**U.S. $0.858**	U.S. $0.831
At end of period	**U.S. $0.897**	U.S.$0.861	**U.S. $0.897**	U.S. $0.861

Consolidated Income Taxes

During the third quarter of 2006 consolidated income taxes consisted of $210 million of current taxes and $98 million of future taxes compared with current taxes of $78 million and future taxes of $118 million in the same period of 2005.

The increase in current taxes in the third quarter of 2006 compared with the third quarter of 2005 was due to higher taxable income.

In the second quarter of 2006, a recovery of future taxes resulted from recording non-recurring tax benefits of $328 million that arose due to changes in the tax rates for the governments of Canada ($198 million), Alberta ($90 million) and Saskatchewan ($40 million). All of this tax legislation received royal assent and was, therefore, substantively enacted in the second quarter of 2006.

Corporate Capital Expenditures

Corporate capital expenditures totaled $23 million in the first nine months of 2006 primarily for various office and information system upgrades.

5.0 LIQUIDITY AND CAPITAL RESOURCES

During the third quarter cash flow from operating activities financed all of our capital requirements and dividend payment. At September 30, 2006 we had $1.4 billion in unused committed credit facilities.

Cash Flow Summary	Three months ended Sept. 30		Nine months ended Sept. 30	
(millions of dollars, except ratios)	**2006**	2005	**2006**	2005
Cash flow - operating activities	**$ 1,461**	$ 1,105	**$ 3,887**	$ 2,605
- financing activities	**$ (333)**	$ (290)	**$ (1,181)**	$ (543)
- investing activities	**$ (713)**	$ (776)	**$ (2,346)**	$ (2,027)
Financial Ratios				
Debt to capital employed *(percent)*			**15.6**	20.4
Corporate reinvestment ratio [(1)] [(2)]			**0.7**	0.9

[(1)] Calculated for the 12 months ended for the dates shown.

[(2)] Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

5.1 OPERATING ACTIVITIES

In the third quarter of 2006, cash generated from operating activities amounted to $1.5 billion compared with $1.1 billion in the third quarter of 2005. Higher cash flow from operating activities was primarily due to higher production volumes and a larger decrease in non-cash working capital resulting primarily from an increase in cash income taxes payable.

5.2 FINANCING ACTIVITIES

In the third quarter of 2006, cash used in financing activities amounted to $333 million compared with $290 million in the third quarter of 2005. During the third 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 third quarter of 2005. The change in non-cash working capital mainly related to a reduction of $242 million in outstanding accounts receivable that had been sold under our securitization program. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

5.3 INVESTING ACTIVITIES

In the third quarter of 2006, cash used in investing activities amounted to $713 million compared with $776 million in the third quarter of 2005. Cash was used primarily for capital expenditures.

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	Nine months ended Sept. 30	Year ended December 31
(millions of dollars)	**2006**	2005
Cash sourced		
Cash flow from operations [1]	**$ 3,294**	$ 3,785
Asset sales	**34**	74
Proceeds from exercise of stock options	**3**	6
Proceeds from monetization of financial instruments	**-**	39
	3,331	3,904
Cash used		
Capital expenditures	**2,289**	3,068
Debt repayment - net	**96**	215
Special dividend on common shares	**-**	424
Ordinary dividends on common shares	**424**	276
Settlement of asset retirement obligations	**24**	41
Other	**12**	32
	2,845	4,056
Net cash (deficiency)	**486**	(152)
Increase (decrease) in non-cash working capital	**(126)**	394
Increase in cash and cash equivalents	**360**	242
Cash and cash equivalents - beginning of period	**249**	7
Cash and cash equivalents - end of period	**$ 609**	$ 249

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

Working capital is the amount by which current assets exceed current liabilities. At September 30, 2006, our working capital deficiency was $600 million compared with $1.0 billion 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.

At September 30, 2006, we had unused committed long and short-term credit facilities totalling $1.4 billion. A total of $12 million of our borrowing credit facilities were used in support of outstanding letters of credit and an additional $58 million of letters of credit were outstanding at September 30, 2006 and supported by dedicated credit lines. During the second quarter of 2006, our long-term revolving credit facilities were extended from three to five year maturities.

We filed a debt shelf prospectus with the Alberta Securities Commission and the U.S. Securities Exchange Commission on September 21, 2006. The shelf prospectus replaces our shelf prospectus dated August 11, 2004, and will enable us to offer up to U.S. $1 billion of debt securities in the United States until October 21, 2008. During the 25 months that the prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale.

Credit Ratings

During the third quarter of 2006, Standard and Poor's Rating Services raised the rating of our long-term corporate credit and senior unsecured debt from BBB to BBB+ with stable outlook.

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 September 30, 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. At September 30, 2006, we had no accounts receivable sold under the securitization program. The securitization program permits the sale of a maximum $350 million of accounts receivable on a revolving basis. The accounts receivable are sold to an unrelated third party and in accordance with the agreement we must provide a loss reserve to replace defaulted receivables. The securitization agreement expires on January 31, 2009.

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 nine 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 nine 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 September 30, 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	38.0	Oct. to Dec. 2006	$ 62.95/MWh	$ 0.5

8.2 INTEREST RATE RISK MANAGEMENT

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

Cross currency swaps resulted in an addition to interest expense of $8 million in the first nine 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 nine months of 2006, these swaps resulted in an offset to interest expense amounting to $2 million.

The amortization of previous interest rate swap terminations resulted in an additional $7 million offset to interest expense in the first nine months of 2006.

8.3 FOREIGN CURRENCY RISK MANAGEMENT

Please refer to note 11 of the Consolidated Financial Statements.

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)		Nine months ended Sept. 30 **2006**	Year ended December 31 2005
Share price [1]	High	**$ 83.00**	$ 69.95
	Low	**$ 58.00**	$ 32.30
	Close at end of period	**$ 71.96**	$ 59.00
Average daily trading volume		**582**	664
Weighted average number of common shares outstanding			
	Basic	**424,187**	423,964
	Diluted	**424,187**	423,964
Issued and outstanding at end of period [2]			
Number of common shares		**424,255**	424,125
Number of stock options		**6,038**	7,285
Number of stock options exercisable		**2,340**	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 September 30, 2006 to October 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:

(millions of dollars)		Nine months ended Sept. 30 **2006**	Year ended December 31 2005
Non-GAAP	Cash flow from operations	**$ 3,294**	$ 3,785
	Settlement of asset retirement obligations	**(24)**	(41)
	Change in non-cash working capital	**617**	(72)
GAAP	Cash flow - operating activities	**$ 3,887**	$ 3,672

13.0 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*
Carbonate	*Sedimentary rock primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite) which forms many petroleum reservoirs*
Bitumen	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. Its viscosity is greater than 10 degrees API*
Petroleum in Place	*The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Oil in place, gas in place and bitumen in place are defined in the same manner*
Coalbed Methane	*Methane (CH_4), the simplest hydrocarbon deposits adsorbed in the pores of coal seams*
Surfactant	*A substance that tends to reduce the surface tension of a liquid in which it is dissolved*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Spider Buoy	*A buoy moored to the seabed that is pulled into the bottom of and secured to the floating production, storage and offloading vessel. Oil is transferred through an in-line swivel via a loading manifold to the piping system of the vessel. When disconnected the buoy will float in a position ready for reconnection*
Front-end Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
FEED	*Front-end engineering design*
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	*One hectare is equal to 2.47 acres*
initial reserves	*Remaining reserves plus cumulative production*
feedstock	*Raw materials which are processed into petroleum products*
design rate 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.

14.0 FORWARD-LOOKING STATEMENTS OR INFORMATION

Certain statements in this release and Interim Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in these forward-looking statements. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "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, forward-looking statements include: our general strategic plans, our production for the Tucker in-situ oil sands project, our Sunrise oil sands project design schedule and water evaluation and stratigraphic drilling plans, our Caribou oil sands drilling plans, our White Rose oil field drilling, development and production plans, the schedule for the Terra Nova oil field's resumption of production, the expected results of our West Bonne Bay drilling program, our plans for prospect mapping for Northwest Territories exploration, our Lloydminster ethanol plant production schedule and planned purchase of grain feedstock, our Minnedosa plant commissioning schedule, the schedule and expected results of our offshore China geophysical and drilling programs, the schedule and our plans for expanding our heavy crude oil mainline and expected results and schedule of our Lloydminster upgrader expansion design plans. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this release and Interim Report. Among the key factors that have a direct bearing on our results of operations are the nature of our involvement in the business of exploration for, and development and production of crude oil and natural gas reserves and the fluctuation of the exchange rates between the Canadian and United States dollar.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, 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

- *adequacy of and fluctuations in oil and natural gas prices;*
- *demand for our products and services and the cost of required inputs;*
- *our ability to replace our reserves;*
- *competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy;*
- *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;*
- *actions by governmental authorities, including changes in environmental and other regulations that may impose restrictions in areas where we operate; and*
- *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.*

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

15.0 CAUTIONARY NOTE REQUIRED BY NATIONAL INSTRUMENT 51-101

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

Husky's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Husky by Canadian securities regulatory authorities, which permits Husky to provide disclosure required by and consistent with those of the United States Securities and Exchange Commission and the Financial Accounting Standards Board in the United States in place of much of the disclosure expected by National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Please refer to "Disclosure of Exemption Under National Instrument 51-101" at page 2 of our Annual Information Form for the year ended December 31, 2005 filed with securities regulatory authorities for further information.

16.0 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 is reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. We use certain terms in this release and Interim Report, such as "estimated resource" and "oil or bitumen in place", that the SEC's guidelines strictly prohibit in filings with the SEC by U.S. oil and gas companies. U.S. investors should refer to our Annual Report on Form 40-F available from us or the SEC for further reserve disclosure.

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars)	**September 30 2006**	December 31 2005
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 609**	$ 249
Accounts receivable	**1,002**	856
Inventories	**437**	471
Prepaid expenses	**62**	40
	2,110	1,616
Property, plant and equipment - (full cost accounting)	**24,642**	22,375
Less accumulated depletion, depreciation and amortization	**9,577**	8,416
	15,065	13,959
Goodwill	**160**	160
Other assets	**54**	62
	$ 17,389	$ 15,797
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 2,443**	$ 2,391
Long-term debt due within one year *(note 5)*	**267**	274
	2,710	2,665
Long-term debt *(note 5)*	**1,455**	1,612
Other long-term liabilities *(note 6)*	**748**	730
Future income taxes	**3,187**	3,270
Commitments and contingencies *(note 8)*		
Shareholders' equity		
Common shares *(note 9)*	**3,532**	3,523
Retained earnings	**5,757**	3,997
	9,289	7,520
	$ 17,389	$ 15,797
Common shares outstanding *(millions) (note 9)*	**424.3**	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 Sept. 30 **2006**	Three months ended Sept. 30 2005	Nine months ended Sept. 30 **2006**	Nine months ended Sept. 30 2005
Sales and operating revenues, net of royalties	**$ 3,436**	$ 2,594	**$ 9,580**	$ 7,038
Costs and expenses				
Cost of sales and operating expenses	**1,944**	1,532	**5,409**	4,014
Selling and administration expenses	**38**	40	**115**	109
Stock-based compensation	**18**	79	**103**	177
Depletion, depreciation and amortization	**411**	311	**1,173**	913
Interest - net *(note 5)*	**19**	-	**68**	16
Foreign exchange *(note 5)*	**5**	(63)	**(32)**	(36)
Other - net	**11**	(57)	**19**	(52)
	2,446	1,842	**6,855**	5,141
Earnings before income taxes	**990**	752	**2,725**	1,897
Income taxes *(note 7)*				
Current	**210**	78	**624**	220
Future	**98**	118	**(83)**	343
	308	196	**541**	563
Net earnings	**$ 682**	$ 556	**$ 2,184**	$ 1,334
Earnings per share				
Basic	**$ 1.61**	$ 1.31	**$ 5.15**	$ 3.15
Diluted	**$ 1.61**	$ 1.31	**$ 5.15**	$ 3.15
Weighted average number of common shares outstanding *(millions)*				
Basic	**424.2**	424.0	**424.2**	423.9
Diluted	**424.2**	424.0	**424.2**	423.9

Consolidated Statements of Retained Earnings

(millions of dollars) (unaudited)	Three months ended Sept. 30 **2006**	Three months ended Sept. 30 2005	Nine months ended Sept. 30 **2006**	Nine months ended Sept. 30 2005
Beginning of period	**$ 5,287**	$ 3,362	**$ 3,997**	$ 2,694
Net earnings	**682**	556	**2,184**	1,334
Dividends on common shares	**(212)**	(60)	**(424)**	(170)
End of period	**$ 5,757**	$ 3,858	**$ 5,757**	$ 3,858

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 Sept. 30		Nine months ended Sept. 30	
	2006	2005	**2006**	2005
Operating activities				
Net earnings	**$ 682**	$ 556	**$ 2,184**	$ 1,334
Items not affecting cash				
Accretion *(note 6)*	**16**	8	**34**	25
Depletion, depreciation and amortization	**411**	311	**1,173**	913
Future income taxes *(note 7)*	**98**	118	**(83)**	343
Foreign exchange	**-**	(66)	**(42)**	(42)
Other	**17**	17	**28**	15
Settlement of asset retirement obligations	**(10)**	(10)	**(24)**	(24)
Change in non-cash working capital *(note 4)*	**247**	171	**617**	41
Cash flow - operating activities	**1,461**	1,105	**3,887**	2,605
Financing activities				
Bank operating loans financing - net	**-**	(34)	**-**	(49)
Long-term debt issue	**-**	576	**1,226**	3,027
Long-term debt repayment	**-**	(782)	**(1,322)**	(3,175)
Proceeds from exercise of stock options	**2**	1	**3**	5
Proceeds from monetization of financial instruments	**-**	-	**-**	30
Dividends on common shares	**(212)**	(60)	**(424)**	(170)
Change in non-cash working capital *(note 4)*	**(123)**	9	**(664)**	(211)
Cash flow - financing activities	**(333)**	(290)	**(1,181)**	(543)
Available for investing	**1,128**	815	**2,706**	2,062
Investing activities				
Capital expenditures	**(746)**	(805)	**(2,289)**	(2,109)
Asset sales	**1**	13	**34**	70
Other	**1**	(21)	**(12)**	(23)
Change in non-cash working capital *(note 4)*	**31**	37	**(79)**	35
Cash flow - investing activities	**(713)**	(776)	**(2,346)**	(2,027)
Increase in cash and cash equivalents	**415**	39	**360**	35
Cash and cash equivalents at beginning of period	**194**	3	**249**	7
Cash and cash equivalents at end of period	**$ 609**	$ 42	**$ 609**	$ 42

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

Nine months ended September 30, 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 Sept. 30												
Sales and operating revenues, net of royalties	**$ 1,600**	$ 1,176	**$ 485**	$ 328	**$ 2,451**	$ 1,808	**$ 776**	$ 716	**$ (1,876)**	$ (1,434)	**$ 3,436**	$ 2,594
Costs and expenses												
Operating, cost of sales, selling and general	**329**	262	**399**	283	**2,396**	1,752	**724**	660	**(1,837)**	(1,363)	**2,011**	1,594
Depletion, depreciation and amortization	**382**	280	**6**	6	**6**	5	**11**	14	**6**	6	**411**	311
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**19**	-	**19**	-
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**5**	(63)	**5**	(63)
	711	542	**405**	289	**2,402**	1,757	**735**	674	**(1,807)**	(1,420)	**2,446**	1,842
Earnings (loss) before income taxes	**889**	634	**80**	39	**49**	51	**41**	42	**(69)**	(14)	**990**	752
Current income taxes	**158**	47	**31**	4	**18**	(3)	**5**	(1)	**(2)**	31	**210**	78
Future income taxes	**123**	142	**(5)**	8	**(2)**	20	**8**	16	**(26)**	(68)	**98**	118
Net earnings (loss)	**$ 608**	$ 445	**$ 54**	$ 27	**$ 33**	$ 34	**$ 28**	$ 27	**$ (41)**	$ 23	**$ 682**	$ 556
Capital expenditures - Three months ended Sept. 30	**$ 612**	$ 701	**$ 44**	$ 38	**$ 29**	$ 11	**$ 59**	$ 57	**$ 10**	$ 6	**$ 754**	$ 813
Nine months ended Sept. 30												
Sales and operating revenues, net of royalties	**$ 4,338**	$ 3,040	**$ 1,294**	$ 1,074	**$ 7,182**	$ 4,871	**$ 1,996**	$ 1,713	**$ (5,230)**	$ (3,660)	**$ 9,580**	$ 7,038
Costs and expenses												
Operating, cost of sales, selling and general	**948**	751	**980**	727	**6,958**	4,657	**1,831**	1,577	**(5,071)**	(3,464)	**5,646**	4,248
Depletion, depreciation and amortization	**1,087**	831	**18**	15	**17**	16	**34**	34	**17**	17	**1,173**	913
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**68**	16	**68**	16
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(32)**	(36)	**(32)**	(36)
	2,035	1,582	**998**	742	**6,975**	4,673	**1,865**	1,611	**(5,018)**	(3,467)	**6,855**	5,141
Earnings (loss) before income taxes	**2,303**	1,458	**296**	332	**207**	198	**131**	102	**(212)**	(193)	**2,725**	1,897
Current income taxes	**457**	169	**84**	13	**57**	(14)	**17**	(3)	**9**	55	**624**	220
Future income taxes	**4**	298	**(14)**	88	**(1)**	83	**18**	40	**(90)**	(166)	**(83)**	343
Net earnings (loss)	**$ 1,842**	$ 991	**$ 226**	$ 231	**$ 151**	$ 129	**$ 96**	$ 65	**$ (131)**	$ (82)	**$ 2,184**	$ 1,334
Capital employed - As at Sept. 30	**$ 9,229**	$ 8,005	**$ 502**	$ 489	**$ 578**	$ 670	**$ 705**	$ 402	**$ (3)**	$ (290)	**$ 11,011**	$ 9,276
Capital expenditures - Nine months ended Sept. 30	**$ 1,923**	$ 1,899	**$ 119**	$ 85	**$ 41**	$ 24	**$ 202**	$ 105	**$ 23**	$ 14	**$ 2,308**	$ 2,127
Total assets - As at Sept. 30	**$ 13,531**	$ 11,920	**$ 943**	$ 806	**$ 1,093**	$ 1,042	**$ 1,070**	$ 783	**$ 752**	$ 161	**$ 17,389**	$ 14,712

[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 Cash Flows - Change in Non-cash Working Capital

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2006	2005	**2006**	2005
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ (255)**	$ (93)	**$ (146)**	$ (113)
Inventories	**28**	(36)	**34**	(176)
Prepaid expenses	**(1)**	15	**(20)**	(3)
Accounts payable and accrued liabilities	**383**	331	**6**	157
Change in non-cash working capital	**155**	217	**(126)**	(135)
Relating to:				
Financing activities	**(123)**	9	**(664)**	(211)
Investing activities	**31**	37	**(79)**	35
Operating activities	**$ 247**	$ 171	**$ 617**	$ 41
b) Other cash flow information:				
Cash taxes paid (received)	**$ (10)**	$ (14)	**$ 163**	$ 145
Cash interest paid	**$ 22**	$ 30	**$ 101**	$ 103

Note 5 Long-term Debt

	Maturity	**Sept. 30 2006**	Dec. 31 2005	**Sept. 30 2006**	Dec. 31 2005
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
7.125% notes	2006	**$ 167**	$ 175	**$ 150**	$ 150
6.25% notes	2012	**446**	467	**400**	400
7.55% debentures	2016	**223**	233	**200**	200
6.15% notes	2019	**335**	350	**300**	300
8.45% senior secured bonds		**-**	99	**-**	85
Medium-term notes	2007-9	**300**	300	**-**	-
8.90% capital securities	2028	**251**	262	**225**	225
Total long-term debt		**1,722**	1,886	**$1,275**	$ 1,360
Amount due within one year		**(267)**	(274)		
		$ 1,455	$ 1,612		

Interest - net consisted of:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2006	2005	**2006**	2005
Long-term debt	**$ 32**	$ 35	**$ 100**	$ 105
Short-term debt	**1**	1	**4**	3
	33	36	**104**	108
Amount capitalized	**(9)**	(36)	**(30)**	(91)
	24	-	**74**	17
Interest income	**(5)**	-	**(6)**	(1)
	$ 19	$ -	**$ 68**	$ 16

Foreign exchange consisted of:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2006	2005	**2006**	2005
Gain on translation of U.S. dollar denominated long-term debt	**$ -**	$ (89)	**$ (67)**	$ (58)
Cross currency swaps	**-**	22	**26**	16
Other losses	**5**	4	**9**	6
	$ 5	$ (63)	**$ (32)**	$ (36)

On September 21, 2006, Husky filed a shelf prospectus, which replaces the Company's shelf prospectus dated August 11, 2004, and will enable Husky to offer up to U.S. $1.0 billion of debt securities in the United States until October 21, 2008. During the 25-month period that the prospectus remains effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. As at September 30, 2006, there were no debt securities issued under this new shelf prospectus.

Note 6 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Nine months ended Sept. 30	
	2006	2005
Asset retirement obligations at beginning of period	**$ 557**	$ 509
Liabilities incurred	**29**	13
Liabilities disposed	**-**	(7)
Liabilities settled	**(24)**	(24)
Accretion	**34**	25
Asset retirement obligations at end of period	**$ 596**	$ 516

At September 30, 2006, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.5 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 7 Income Taxes

There were no tax rate benefits recorded during the third quarter of 2006 or 2005. In the second quarter of 2006, a recovery of future taxes resulted from recording non-recurring tax benefits of $328 million that arose due to changes in the tax rates for the governments of Canada ($198 million), Alberta ($90 million) and Saskatchewan ($40 million). All of this tax legislation received royal assent and was, therefore, substantively enacted in the second quarter of 2006.

Note 8 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 9 Share Capital

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

Common Shares

Changes to issued common shares were as follows:

	Nine months ended September 30			
	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	129,765	9	375,136	16
Balance at September 30	**424,254,843**	**$ 3,532**	424,111,550	$ 3,522

Stock Options

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

	Nine months ended September 30			
	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	742	$ 70.25	405	$ 43.19
Exercised for common shares	(130)	$ 22.18	(346)	$ 15.62
Surrendered for cash	(1,641)	$ 23.51	(2,241)	$ 18.53
Forfeited	(218)	$ 40.48	(441)	$ 24.01
Outstanding at September 30	**6,038**	**$ 31.45**	7,341	$ 25.23
Options exercisable at September 30	**2,340**	**$ 24.14**	1,557	$ 23.47

	September 30, 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
$13.96 - $14.99	69	$ 14.58	1	69	$ 14.58
$15.00 - $22.99	125	$ 20.13	2	49	$ 18.81
$23.00 - $23.99	4,413	$ 23.83	3	2,114	$ 23.83
$24.00 - $39.99	330	$ 32.15	3	64	$ 31.71
$40.00 - $55.99	404	$ 52.17	4	44	$ 48.63
$56.00 - $73.80	697	$ 71.00	5	-	$ -
	6,038	**$ 31.45**	**3**	**2,340**	**$ 24.14**

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2006	2005	**2006**	2005
Employer current service cost	**$ 4**	$ 4	**$ 13**	$ 13
Interest cost	**2**	2	**7**	7
Expected return on plan assets	**(1)**	(2)	**(4)**	(6)
Amortization of net actuarial losses	**-**	1	**-**	2
	$ 5	$ 5	**$ 16**	$ 16

Note 11 Financial Instruments and Risk Management

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

	Sept. 30 2006	Dec. 31 2005
Commodity price risk management		
Power consumption	**$ 1**	$ -
Interest rate risk management		
Interest rate swaps	**6**	7
Foreign currency risk management		
Foreign exchange contracts	**(31)**	(32)

Commodity Price Risk Management

Power Consumption

At September 30, 2006, the Company had hedged power consumption as follows:

	Notional Volumes *(MW)*	Term	Price
Fixed price purchase	38.0	Oct. to Dec. 2006	$62.95/MWh

The impact of the hedge program during the first nine months of 2006 was a gain of $1 million (2005 - gain of $1 million).

Natural Gas Contracts

At September 30, 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	30,583	$ 3
Physical sale contracts	(30,583)	$ 2

Interest Rate Risk Management

During the first nine months of 2006, the Company realized a gain of $1 million (2005 - gain of $11 million) from interest rate risk management activities.

Foreign Currency Risk Management

During the first nine months of 2006, the Company realized a loss of $22 million (2005 - loss of $4 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 September 30, 2006, no accounts receivable had been sold under the program compared with $350 million in outstanding accounts receivable sold at December 31, 2005.

Husky Energy Inc. will host a conference call for analysts and investors on Friday, October 20, 2006 at 4:15 p.m. Eastern time to discuss Husky's third quarter results. To participate please dial 1-800-289-6406 beginning at 4:05 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 21306700. The Postview will be available until Monday, November 20, 2006.

Media are invited to listen to the conference call by dialing 1-800-377-5794 beginning at 4:05 p.m. Eastern time.

- End -

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