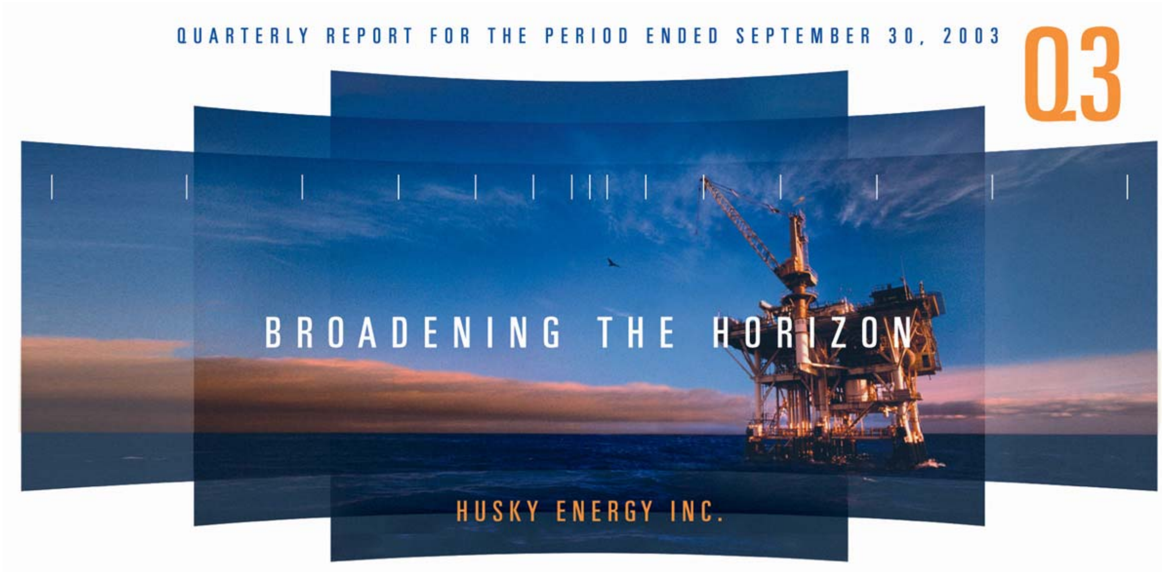
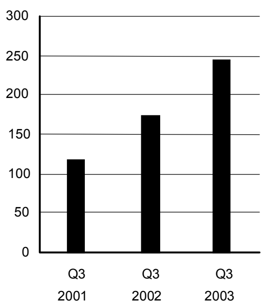
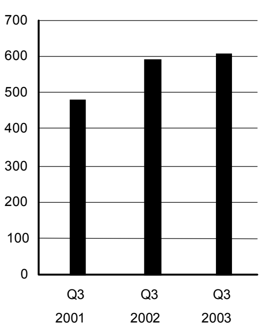


HUSKY ENERGY ANNOUNCES SOLID THIRD QUARTER RESULTS WITH NINE MONTHS EARNINGS OF $1.1 BILLION

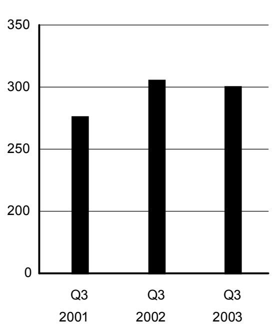
Quarterly Net Earnings
($ millions)



Quarterly Cash Flow from Operations
($ millions)



Quarterly Total Production
(mboe/day)



Husky Energy Inc. is pleased to report third quarter net earnings of $243 million and $1.1 billion for the first nine months of 2003.

Net earnings of $243 million or $0.54 per share (diluted) in the third quarter of 2003 compared with $173 million or $0.38 per share (diluted) in the third quarter of 2002, is an increase of 40 percent. Cash flow from operations in the third quarter of 2003 was $604 million or $1.42 per share (diluted), up from $590 million or $1.39 per share (diluted) in the third quarter of 2002.

"Notwithstanding high commodity prices counteracted by a strong Canadian dollar, we are pleased with our strong financial performance for the third quarter and for the first nine months of 2003," said President and Chief Executive Officer, Mr. John C.S. Lau. "In addition, we achieved financial and operational successes with the acquisition of Marathon Canada Limited, and the incremental potential reserves and development progress at the White Rose oil field."

Production in the third quarter of 2003 averaged 300,200 barrels of oil equivalent ("boe") per day, compared with 305,100 boe per day in the third quarter of 2002, a decrease of two percent mainly due to divestitures, turnarounds at producing facilities and natural reservoir declines. Total crude oil and natural gas liquids production for the third quarter of 2003 was 202,600 barrels per day, down four percent from 211,500 barrels per day in the third quarter of 2002. Natural gas production in the third quarter of 2003 was 585.7 million cubic feet per day, up four percent from 561.6 million cubic feet per day in the same quarter of 2002.

For the first nine months of 2003, production averaged 307,600 boe per day compared with 294,300 boe per day for the first nine months of 2002, an increase of five percent. Total crude oil and natural gas liquids production for the first nine months of 2003 increased by four percent to 208,300 barrels per day from 199,800 barrels per day for the same period of 2002. Natural gas production in the first nine months of 2003 averaged 595.4 million cubic feet per day compared with 566.5 million cubic feet per day for the first nine months of 2002, an increase of five percent.

Husky's net earnings for the first nine months of 2003 were $1.1 billion or $2.60 per share (diluted) compared with $562 million or $1.31 per share (diluted) in the first nine months of 2002, an increase of 91 percent. Husky's debt, net of cash and cash equivalents, decreased by $834 million. As at September 30, 2003, Husky's net debt stood at $1.2 billion, down 40 percent from $2.1 billion at December 31, 2002. Cash flow from operations in the first nine months of 2003 also increased by 29 percent to $1.9 billion or $4.44 per share (diluted) from $1.5 billion or $3.43 per share (diluted) for the first nine months of 2002.

"Husky Energy continues to make good progress towards our goals", said Mr. Lau. "All cash requirements for the Marathon Canada Limited acquisition and the special dividend to our shareholders were made from the cash surplus at the end of September. With our financial strength and strong balance sheet, Husky has built a solid platform for future growth."

Highlights

(millions of dollars, except per share amounts)	Three months ended September 30 2003	Three months ended September 30 2002	% Change	Nine months ended September 30 2003	Nine months ended September 30 2002	% Change
Sales and operating revenues, net of royalties	**$ 1,871**	$ 1,669	⇧ 12	**$ 5,858**	$ 4,687	⇧ 25
Cash flow from operations	**604**	590	⇧ 2	**1,891**	1,461	⇧ 29
Per share - Basic	**1.42**	1.39	⇧ 2	**4.46**	3.44	⇧ 30
- Diluted	**1.42**	1.39	⇧ 2	**4.44**	3.43	⇧ 29
Segmented earnings						
Upstream	**$ 208**	$ 206	⇧ 1	**$ 874**	$ 478	⇧ 83
Midstream	**41**	27	⇧ 52	**139**	113	⇧ 23
Refined Products	**21**	16	⇧ 31	**23**	33	⇩ 30
Corporate and eliminations	**(27)**	(76)	⇧ 64	**40**	(62)	⇧ 165
Net earnings	**$ 243**	$ 173	⇧ 40	**$ 1,076**	$ 562	⇧ 91
Per share - Basic	**$ 0.55**	$ 0.38	⇧ 45	**$ 2.61**	$ 1.31	⇧ 99
- Diluted	**0.54**	0.38	⇧ 42	**2.60**	1.31	⇧ 98
Dividend declared						
Per share - Ordinary	**0.10**	0.09	⇧ 11	**0.28**	0.27	⇧ 4
- Special	**1.00**	-	-	**1.00**	-	-
Daily production, before royalties						
Light crude oil & NGL *(mbbls/day)*	**65.2**	71.9	⇩ 9	**71.4**	61.0	⇧ 17
Medium crude oil *(mbbls/day)*	**38.2**	44.4	⇩ 14	**39.7**	45.2	⇩ 12
Heavy crude oil *(mbbls/day)*	**99.2**	95.2	⇧ 4	**97.2**	93.6	⇧ 4
Total crude oil & NGL [(1)] *(mbbls/day)*	**202.6**	211.5	⇩ 4	**208.3**	199.8	⇧ 4
Natural gas *(mmcf/day)*	**585.7**	561.6	⇧ 4	**595.4**	566.5	⇧ 5
Barrels of oil equivalent (6:1) *(mboe/day)*	**300.2**	305.1	⇩ 2	**307.6**	294.3	⇧ 5

[(1)] *Includes divestitures of 8 mbbls per day in the fourth quarter of 2002.*

Highlights

UPSTREAM
Production

Total production in the third quarter of 2003 averaged 300,200 barrels of oil equivalent per day and comprised 202,600 gross barrels of crude oil per day and 586 million gross cubic feet of natural gas per day.

- the lower crude oil production in the third quarter of 2003 compared with the third quarter of 2002 was due primarily to divestitures, turnarounds at producing facilities and natural reservoir declines.
- in Western Canada 206 net oil wells were completed during the third quarter.
- heavy oil production averaged 99,200 barrels per day in the third quarter of 2003 compared with 95,200 barrels per day in the third quarter of 2002.
- Husky's production of light crude oil from Terra Nova averaged 14,600 barrels per day during the third quarter of 2003 compared with 10,800 barrels per day during the third quarter of 2002.
- Husky's production at Wenchang averaged 20,300 barrels per day in the third quarter of 2003 compared with 21,900 barrels per day during the third quarter of 2002.

Natural gas production averaged 586 million cubic feet per day in the third quarter of 2003, an increase of four percent compared with the third quarter of 2002. The higher natural gas production in the third quarter of 2003 was mainly attributable to:

- the 2003 third quarter drilling program, which resulted in 118 net natural gas well completions.

- well completions and tie-ins in the Alberta foothills area, which added 19 million cubic feet per day of natural gas.

Acquisition of Marathon Canada

Husky acquired Marathon Canada Limited ("Marathon Canada") and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. for a total purchase price of U.S. $588 million. In a separate transaction, Husky sold certain of the Marathon Canada assets to a third party for U.S. $320 million. The assets retained by Husky comprise approximately 183 billion cubic feet of proved natural gas reserves and 9.2 million barrels of proved crude oil and natural gas liquids. The retained assets will add 80 to 90 million cubic feet per day of natural gas production and 4,500 barrels per day of liquids production. The transactions closed on October 1, 2003.

Shackleton Natural Gas

Husky drilled and completed 34 net natural gas wells in the Shackleton area during the third quarter of 2003. At the end of September 2003, 174 net natural gas wells in the Shackleton area were producing an aggregate of approximately 42 million cubic feet of gas per day. Husky expects to drill and tie-in 40 net wells during the fourth quarter of 2003 and increase compression capacity to over 50 million cubic feet per day.

Bolney/Celtic Thermal

Husky started field construction of the Bolney/Celtic thermal project during the third quarter of 2003 and will be on-stream by the end of 2003. As part of stage two, five horizontal well pairs were brought on-stream during the third quarter at Celtic. In addition, facilities incorporating new heat integration technology that will increase steam capacity and reduce fuel consumption will be commissioned in the fourth quarter. The project will also recycle water and recover waste gas, further improving environmental and cost performance. Production at the project reached 8.7 mbbls per day in September 2003, up 58 percent from 5.5 mbbls per day during the second quarter of 2003.

Oil Sands - Alberta

Tucker

During the third quarter of 2003 Husky continued to work with the Alberta Energy and Utilities Board and Alberta Environment on the Tucker project application. Work on the project during the third quarter of 2003 also involved modeling optimal well bore and well pad design, facilities engineering and assessment of major equipment. The Tucker project is a 30,000 barrel per day in-situ bitumen operation utilizing steam assisted gravity drainage technology.

Kearl

The preliminary results from 212 stratigraphic test wells were incorporated into a detailed geological model during the third quarter of 2003, and data was prepared for the environmental impact assessment. Preparation for a stratigraphic test well program in 2004 commenced in the third quarter of 2003.

Exploration

Western Canada

During the third quarter of 2003 Husky drilled 15 net exploration wells, which included four net oil well completions and 11 net natural gas well completions.

Three wells were completed for Mississippian natural gas potential during the third quarter. These wells tested at a combined rate of 39 million cubic feet per day (Husky's share 14 million cubic feet per day). The wells are expected to be tied in and producing by the end of 2003. Two exploration wells are currently drilling in the foothills, a 100 percent working interest well at Palliser and a 50 percent working interest well at Cordel.

Offshore Canadian East Coast

During the third quarter of 2003, Husky completed testing an oil and gas discovery located in the southern part of the White Rose oil field. The F-04 and F-04Z well was drilled into a separate geological structure and encountered approximately 140 metres of natural gas and 40 metres of oil in Avalon sandstone. Preliminary estimates indicate approximately 20 to 30 million barrels of recoverable oil and 200 to 250 billion cubic feet of natural gas-in-place. Planning and design to produce the oil in the F-04 structure from the White Rose floating production storage and offloading facility ("FPSO") is currently underway.

Offshore China

During the third quarter of 2003 a 1,000 square kilometre 3-D seismic program was completed on Block 23/15 in the South China Sea. The data is currently being processed and interpreted to select prospective drilling locations.

Major Project Update

East Coast, Canada Offshore

White Rose

During the third quarter of 2003, the third and final glory hole was completed and drilling of the first development well commenced in October 2003. Prior to first oil, four producing wells, four water injection wells and one gas injection well will be drilled. The hull for the FPSO was launched in Korea in July 2003 and the turret arrived from Abu Dhabi in August 2003. The turret is currently being installed on the hull and the combined structure is expected to arrive at Marystown, Newfoundland and Labrador in early 2004. The FPSO's topside modules, which will be installed on the hull, are being engineered and fabricated in St. John's and Marystown, Newfoundland and Labrador.

MIDSTREAM

Husky Lloydminster Upgrader

At the Husky Lloydminster Upgrader, engineering of known debottleneck projects continued during the third quarter. An implementation strategy is being developed and several projects are in the detailed design stage. These projects are expected to increase the plant's productive capacity from 77,000 barrels per day to 82,000 barrels per day by the end of 2004.

REFINED PRODUCTS

During the third quarter of 2003, Husky completed conversion of two Calgary outlets to Husky Markets and completed construction of a Husky Market at a location in Edmonton. Husky Markets are upgraded retail facilities offering a broad selection of products to consumers.

StorePoint, an integrated point of sale system was installed at 31 outlets during the third quarter of 2003 completing the total StorePoint systems installed of 305.

Management's Discussion & Analysis

Management's Discussion and Analysis should be read in conjunction with the unaudited consolidated financial statements of the Company for the nine months ended September 30, 2003 and the audited consolidated financial statements and management's discussion and analysis for the year ended December 31, 2002, which are included in the Company's annual report for the year ended December 31, 2002. All comparisons refer to the third quarter of 2003 compared with the third quarter of 2002 and the first nine months of 2003 compared with the first nine months of 2002, unless otherwise indicated. All dollar amounts, except per share data, are in millions of Canadian dollars, unless otherwise indicated.

The calculation of barrels of oil equivalent ("boe") and thousands of cubic feet of gas equivalent ("mcfge") are based on a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. All production volumes quoted are gross, the Company's working interest share before royalties, and realized prices include the effect of hedging gains and losses, unless otherwise indicated. Crude oil has been classified as the following: light crude oil has an API gravity of 30 degrees or more; medium crude oil has an API gravity of 21 degrees or more and less than 30 degrees; heavy crude oil has an API gravity of less than 21 degrees.

Management's Discussion and Analysis contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Company's financial performance. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations generated by each business segment represents a measurement of financial performance for which each reporting business segment is responsible. The other items required to arrive at cash flow from operating activities are considered to be a corporate responsibility.

Quarterly Comparison

		Three months ended				
		Sept. 30 2003	June 30 2003	March 31 2003	Dec. 31 2002	Sept. 30 2002
Sales and operating revenues, net of royalties		**$ 1,871**	$ 1,769	$ 2,218	$ 1,697	$ 1,669
Cash flow from operations		**604**	540	747	635	590
Net earnings		**243**	427	406	242	173
Per share - Basic		**0.55**	1.06	1.01	0.57	0.38
- Diluted		**0.54**	1.05	1.00	0.57	0.38
Daily production, before royalties						
Light crude oil & NGL	*(mbbls/day)*	**65.2**	74.9	74.3	78.8	71.9
Medium crude oil	*(mbbls/day)*	**38.2**	39.4	41.4	43.5	44.4
Heavy crude oil	*(mbbls/day)*	**99.2**	94.7	97.8	99.4	95.2
Natural gas	*(mmcf/day)*	**585.7**	609.4	591.2	577.4	561.6
Barrels of oil equivalent (6:1)	*(mboe/day)*	**300.2**	310.6	312.1	317.9	305.1

Consolidated Results Summary

Husky's net earnings for the third quarter of 2003 were $243 million or $0.54 per share (diluted) compared with net earnings of $173 million or $0.38 per share (diluted) during the third quarter of 2002. Higher earnings in the third quarter of 2003 were mainly the result of the following factors:

- higher realized natural gas prices
- higher heavy crude oil production
- higher natural gas production
- higher upgrading netbacks
- higher synthetic crude oil sales volume
- higher asphalt margins
- lower foreign exchange impact
- higher interest capitalization

partially offset by:

- lower realized crude oil prices
- lower light and medium crude oil production
- higher per unit operating costs and depletion, depreciation and amortization expense
- higher income taxes

Husky's net earnings for the first nine months of 2003 were $1.1 billion or $2.60 per share (diluted) compared with net earnings of $562 million or $1.31 per share (diluted) during the comparable period of 2002. Higher earnings in the first nine months of 2003 compared with the same period in 2002 were mainly the result of the following factors:

- higher natural gas and crude oil prices
- higher light and heavy crude oil and natural gas production
- higher upgrading netbacks and synthetic crude oil sales
- foreign exchange gains on U.S. denominated long-term debt

partially offset by:

- higher royalties
- higher operating costs and depletion, depreciation and amortization expense
- lower medium crude oil production
- lower light oil refined products margins
- higher income taxes

Cash flow from operating activities for the third quarter of 2003 was $619 million compared with $450 million in the same quarter of 2002. Cash flow from operating activities amounted to $2.0 billion in the first nine months of 2003 compared with $1.3 billion in the same period in 2002, an increase of 57 percent.

Capital expenditures in the nine months ended September 30, 2003 amounted to $1.3 billion, five percent higher than in the same period in 2002.

Net debt at September 30, 2003 amounted to $1.2 billion compared with $2.1 billion at December 31, 2002. The ratio of net debt to total net debt plus equity at September 30, 2003 was 18 percent compared with 29 percent at December 31, 2002.

2003 Production Forecast

Husky provided a production forecast for 2003 at the end of the first quarter of 2003. We have revised our annual natural gas production forecast upwards to average between 610 and 640 mmcf per day from our original forecast of 590 to 620 mmcf per day. This increase is a result of the acquisition of Marathon Canada. The other forecasted items remain unchanged. Overall annual production is expected to average between 310 and 330 mboe per day. Light crude oil and NGL is expected to average between 70 and 75 mbbls per day. Medium crude oil is expected to average between 40 and 45 mbbls per day and heavy crude oil is expected to average between 100 and 110 mbbls per day.

Business Environment

During the third quarter and first nine months of 2003, the spot price trend line for West Texas Intermediate crude oil ("WTI") declined. In the third quarter of 2003 WTI reached a high of U.S. $32.41 on August 7, 2003, the low was U.S. $26.93 on September 19, 2003 and the average was U.S. $30.20 for the quarter.

After restrictions in August due to damaged infrastructure, production from Iraq was reported in excess of 1.4 million barrels per day in September 2003, 60 percent of pre-war average levels. On September 24, 2003, with U.S. crude oil inventories within five percent of normal seasonal levels and heating oil inventories essentially at normal levels, OPEC members agreed to a production cut to dampen winter over supply.

During the third quarter of 2003, the NYMEX natural gas spot prices trended down. The high spot price recorded in the quarter was U.S. $5.56/mmbtu on July 9, 2003, the low was U.S. $4.33/mmbtu on September 19, 2003 and the average for the quarter was U.S. $4.97/mmbtu.

Toward the end of September natural gas prices averaged below the quarter's trend line as U.S. gas storage levels began to climb and by October 3, 2003 had reached a level five percent short of three trillion cubic feet, a level considered to be adequate to satisfy heating season demand if achieved by November.

Industry Benchmarks *(averages)*

		Three months ended				
		Sept. 30 2003	June 30 2003	March 31 2003	Dec. 31 2002	Sept. 30 2002
West Texas Intermediate ("WTI")	*(U.S. $/bbl)*	**$ 30.20**	$ 28.91	$ 33.86	$ 28.15	$ 28.27
NYMEX natural gas	*(U.S. $/mmbtu)*	**$ 4.97**	$ 5.39	$ 6.60	$ 3.99	$ 3.26
AECO natural gas	*($/GJ)*	**$ 5.97**	$ 6.63	$ 7.51	$ 4.98	$ 3.08
WTI/Lloyd Blend differential	*(U.S. $/bbl)*	**$ 8.73**	$ 6.98	$ 8.12	$ 8.14	$ 5.99
U.S./Canadian dollar exchange rate	*(U.S. $)*	**$ 0.725**	$ 0.716	$ 0.663	$ 0.638	$ 0.640

Risk Management

Husky's results of operations are affected by the volatility of market based factors beyond its control. Most significant among them are commodity prices, interest rates and foreign exchange rates. Husky manages market risk, when warranted, through the use of various financial instruments and contracts in order to protect earnings and cash flow and to ensure the financial capacity to undertake the Company's business plans.

The Company implemented a corporate hedging program for 2003 and 2004 to manage volatility of natural gas and crude oil prices.

Natural Gas

At September 30, 2003, 240 mmcf per day of natural gas was hedged for October 2003 and 100 mmcf per day for November and December 2003 at an average price of U.S. $5.34/mmbtu. At September 30, 2003 the marked to market value of these contracts was a gain of U.S. $9.1 million.

The program's natural gas forward contracts were in effect from April to September 2003. During that period Husky recorded a gain totalling $9.3 million on these contracts.

Crude Oil

At September 30, 2003, 85 mbbls per day was hedged for October to December 2003 at an average price of U.S. $29.25 per barrel. At September 30, 2003, the marked to market value of these contracts was a gain of U.S. $3.8 million.

In October 2003, the Company hedged additional crude oil of 10 mbbls per day for October to December 2003 at an average fixed price of U.S. $31.36 per barrel. The marked to market value of these contracts is insignificant as of the date of this report.

The crude oil hedges were in effect from January to September 2003. During that period Husky recorded a loss totalling $16.6 million on these contracts.

Husky has hedged 80 mbbls per day of crude oil from January 2004 to December 2004 at U.S. $27.35 per barrel.

Husky has a put option contract in effect from July to December 2003 on 3,680,000 barrels of crude oil with a strike price of U.S. $27 per barrel. The contract is a full term settlement contract such that if the average price for WTI is below U.S. $27 per barrel for that period the differential will be paid to Husky. Husky paid U.S. $6.1 million for the contract that is being charged to earnings over the contract period. At September 30, 2003 the fair value of the contract was insignificant.

Power Consumption

In September 2003, the Company hedged power consumption of 175,680 MWh from January 2004 to December 2004 at a fixed price of $46.25/MWh. At September 30, 2003 the marked to market value of the contract was insignificant.

Foreign Exchange

In the first nine months of 2003 Husky entered into cross currency debt swap contracts the terms of which are as follows:

- U.S. $150 million at 6.875 percent swapped at $1.5250 to $229 million at 8.50 percent until November 15, 2003
- U.S. $150 million at 7.125 percent swapped at $1.4500 to $218 million at 8.74 percent until November 15, 2006
- U.S. $150 million at 6.250 percent swapped at $1.4100 to $212 million at 7.41 percent until June 15, 2012

At September 30, 2003 the actual U.S./Canadian exchange was $1.3504. The out of the money differential from the above contracts resulted in an offset to foreign currency gains recorded in the first nine months of 2003 on U.S. dollar denominated long-term debt of $50 million.

In the first nine months of 2003 the cross currency swaps resulted in an addition to interest expense amounting to $9.9 million.

Interest Rates

Husky has an interest rate swap 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 2003 this swap resulted in an offset to interest expense amounting to $3.2 million.

Husky has an interest rate swap on U.S. $200 million of long-term debt effective February 12, 2002 whereby 7.55 percent was swapped for an average U.S. LIBOR + 194 bps until November 15, 2011. During the first nine months of 2003 this swap resulted in an offset to interest expense amounting to U.S. $6.4 million.

Results of Operations

UPSTREAM
Earnings and Production

Third Quarter

Earnings from Husky's upstream business segment were marginally higher at $208 million in the third quarter of 2003 compared with the third quarter of 2002. Earnings attributable to the upstream business segment were affected by the following:

- higher realized natural gas prices, including a hedging gain of $0.18 per mcfge
- higher natural gas production

substantially offset by:

- lower realized prices for light crude oil, including a hedging loss of $1.14 per barrel
- lower realized prices for medium crude oil, including a hedging loss of $2.56 per barrel
- lower light and medium crude oil production
- higher unit operating costs reflecting increased energy and energy related costs, higher maintenance costs resulting from wet weather conditions in the Lloydminster heavy oil area offset to a degree by lower unit operating costs at Wenchang and Terra Nova
- lower heavy crude oil prices
- higher unit depletion, depreciation and amortization expense related to the higher capital associated with offshore producing properties and increased capital requirements to maintain production in the mature Western Canada oil and shallow natural gas fields

Nine Months

Earnings from Husky's upstream business segment increased $396 million to $874 million in the first nine months of 2003 from $478 million in the same period in 2002. The higher earnings attributable to the upstream business segment were due primarily to the following:

- higher realized prices for natural gas and crude oil
- higher production of light and heavy crude oil and natural gas

partially offset by:

- higher royalties
- higher unit operating costs
- higher unit depletion, depreciation and amortization expense
- lower production of medium crude oil

Production in the Third Quarter of 2003 Compared with the Second Quarter of 2003

Production from Husky's properties in Western Canada averaged 265 mboe per day in the third quarter of 2003, substantially the same as 267 mboe per day in the second quarter of 2003.

- light and medium crude oil production averaged 59 mbbls per day in the third quarter of 2003 compared with 61 mbbls per day in the second quarter of 2003. The lower production volume was primarily due to divestitures and natural declines.
- heavy crude oil production averaged 99 mbbls per day in the third quarter of 2003 compared with 95 mbbls per day in the second quarter of 2003. The increased heavy oil production resulted primarily from the cessation of weather related problems and higher production from the expansion of the Bolney/Celtic thermal project.
- natural gas production averaged 586 mmcf per day in the third quarter of 2003 compared with 609 mmcf per day in the second quarter of 2003, down four percent. The lower natural gas production in the third quarter was due mainly to plant turnarounds and natural declines partially offset by new wells in the foothills of Alberta.

Husky's production from the Terra Nova oil field offshore Newfoundland averaged 14.6 mbbls per day in the third quarter of 2003 compared with 19.0 mbbls per day in the second quarter of 2003. Production was lower at Terra Nova as a result of a turnaround from August 16 to August 31 followed by mechanical problems preventing gas injection. Production at Terra Nova returned to normal levels on October 10, 2003.

Husky's production from the Wenchang oil field offshore south China averaged 20.3 mbbls per day in the third quarter of 2003 compared with 24.5 mbbls per day in the second quarter of 2003. The lower production was due to natural reservoir decline and weather related issues.

Upstream Earnings Summary

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Gross revenues	**$ 866**	$ 862	**$ 2,937**	$ 2,198
Royalties	**121**	124	**458**	314
Hedging	**5**	-	**15**	-
Net revenues	**740**	738	**2,464**	1,884
Operating and administrative expenses	**199**	189	**634**	523
Depletion, depreciation and amortization ("DD&A")	**229**	218	**691**	620
Income taxes	**104**	125	**265**	263
Earnings	**$ 208**	$ 206	**$ 874**	$ 478

Net Revenue Variance Analysis

	Crude oil & NGL	Natural gas	Other	Total
Three months ended September 30, 2002	$ 573	$ 149	$ 16	$ 738
Price changes	60	107	-	167
Volume changes	(173)	7	-	(166)
Royalties	33	(30)	-	3
Hedging	(15)	10	-	(5)
Processing and sulphur	-	-	3	3
Three months ended September 30, 2003	**$ 478**	**$ 243**	**$ 19**	**$ 740**
Nine months ended September 30, 2002	$ 1,407	$ 444	$ 33	$1,884
Price changes	561	441	-	1,002
Volume changes	(311)	28	-	(283)
Royalties	(12)	(132)	-	(144)
Hedging	(21)	6	-	(15)
Processing and sulphur	-	-	20	20
Nine months ended September 30, 2003	**$ 1,624**	**$ 787**	**$ 53**	**$2,464**

Average Realized Prices

		Three months ended September 30		Nine months ended September 30	
		2003	2002	**2003**	2002
Before commodity hedging					
Light crude oil & NGL	*($/bbl)*	**$ 34.15**	$ 38.54	**$ 40.20**	$ 32.13
Medium crude oil	*($/bbl)*	**$ 29.68**	$ 34.76	**$ 32.76**	$ 30.11
Heavy crude oil	*($/bbl)*	**$ 25.13**	$ 31.41	**$ 27.75**	$ 26.79
Natural gas	*($/mcf)*	**$ 5.40**	$ 3.42	**$ 6.21**	$ 3.50
After commodity hedging					
Light crude oil & NGL	*($/bbl)*	**$ 33.01**	$ 38.54	**$ 39.72**	$ 32.13
Medium crude oil	*($/bbl)*	**$ 27.12**	$ 34.76	**$ 31.60**	$ 30.11
Heavy crude oil	*($/bbl)*	**$ 25.13**	$ 31.41	**$ 27.75**	$ 26.79
Natural gas	*($/mcf)*	**$ 5.58**	$ 3.42	**$ 6.25**	$ 3.50

Royalty Rates

	Three months ended September 30		Nine months ended September 30	
Percentage of upstream sales revenues, before royalties	**2003**	2002	**2003**	2002
Crude oil & NGL	**12**	14	**12**	13
Natural gas	**19**	16	**22**	18
Total	**14**	15	**16**	14

Daily Production, Before Royalties					
		Three months ended September 30		Nine months ended September 30	
		2003	2002	**2003**	2002
Light crude oil & NGL	*(mbbls/day)*	**65.2**	71.9	**71.4**	61.0
Medium crude oil	*(mbbls/day)*	**38.2**	44.4	**39.7**	45.2
Heavy crude oil	*(mbbls/day)*	**99.2**	95.2	**97.2**	93.6
Total crude oil & NGL	*(mbbls/day)*	**202.6**	211.5	**208.3**	199.8
Natural gas	*(mmcf/day)*	**585.7**	561.6	**595.4**	566.5
Barrels of oil equivalent (6:1)	*(mboe/day)*	**300.2**	305.1	**307.6**	294.3

Product Mix				
	Three months ended September 30		Nine months ended September 30	
Percentage of upstream sales revenues, net of royalties	**2003**	2002	**2003**	2002
Crude oil & NGL	**65**	79	**67**	75
Natural gas	**35**	21	**33**	25
	100	100	**100**	100

Operating Netbacks

Western Canada

Light Crude Oil Netbacks [1]				
	Three months ended September 30		Nine months ended September 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 37.65**	$ 35.97	**$ 41.36**	$ 32.85
Royalties	**6.10**	5.51	**7.57**	4.31
Hedging	**2.25**	-	**1.00**	-
Operating costs	**6.24**	9.84	**8.73**	9.69
Netback	**$ 23.06**	$ 20.62	**$ 24.06**	$ 18.85

Medium Crude Oil Netbacks [1]				
	Three months ended September 30		Nine months ended September 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 29.82**	$ 34.26	**$ 32.94**	$ 29.82
Royalties	**4.39**	6.28	**5.52**	5.23
Hedging	**2.48**	-	**1.13**	-
Operating costs	**9.80**	7.59	**9.55**	7.01
Netback	**$ 13.15**	$ 20.39	**$ 16.74**	$ 17.58

Heavy Crude Oil Netbacks [1]				
	Three months ended September 30		Nine months ended September 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 25.22**	$ 31.23	**$ 27.85**	$ 26.64
Royalties	**2.58**	4.58	**3.04**	3.22
Operating costs	**8.64**	6.75	**9.30**	6.75
Netback	**$ 14.00**	$ 19.90	**$ 15.51**	$ 16.67

Natural Gas Netbacks [2]				
	Three months ended September 30		Nine months ended September 30	
Per mcfge	**2003**	2002	**2003**	2002
Sales revenues	**$ 5.34**	$ 3.60	**$ 6.13**	$ 3.61
Royalties	**1.09**	0.65	**1.40**	0.73
Hedging	**(0.18)**	-	**(0.04)**	-
Operating costs	**0.84**	0.76	**0.80**	0.69
Netback	**$ 3.59**	$ 2.19	**$ 3.97**	$ 2.19

Total Western Canada Upstream Netbacks [1]				
	Three months ended September 30		Nine months ended September 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 29.73**	$ 29.06	**$ 33.41**	$ 26.28
Royalties	**4.68**	4.76	**5.91**	4.11
Hedging	**0.21**	-	**0.21**	-
Operating costs	**7.24**	6.56	**7.61**	6.26
Netback	**$ 17.60**	$ 17.74	**$ 19.68**	$ 15.91

Terra Nova Crude Oil Netbacks				
	Three months ended September 30		Nine months ended September 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 39.38**	$ 38.62	**$ 39.17**	$ 34.63
Royalties	**0.99**	0.39	**0.76**	0.35
Operating costs	**3.64**	2.68	**3.34**	3.74
Netback	**$ 34.75**	$ 35.55	**$ 35.07**	$ 30.54

Wenchang Crude Oil Netbacks				
	Three months ended September 30		Nine months ended September 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 37.74**	$ 41.64	**$ 41.78**	$ 41.64
Royalties	**3.20**	2.58	**3.43**	2.58
Operating costs	**1.98**	3.23	**1.72**	3.23
Netback	**$ 32.56**	$ 35.83	**$ 36.63**	$ 35.83

Total Upstream Segment Netbacks [1]				
	Three months ended September 30		Nine months ended September 30	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 30.74**	$ 30.31	**$ 34.36**	$ 27.02
Royalties	**4.40**	4.45	**5.44**	3.91
Hedging	**0.19**	-	**0.18**	-
Operating costs	**6.71**	6.19	**6.94**	6.08
Netback	**$ 19.44**	$ 19.67	**$ 21.80**	$ 17.03

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

MIDSTREAM

Third Quarter

Earnings from Husky's midstream business segment were $41 million in the third quarter of 2003, up $14 million compared with $27 million in the same quarter in 2002. Midstream earnings increased as a result of the following factors:

- higher upgrading margins primarily due to a wider average differential between heavy and light crude oil
- higher sales of synthetic crude oil
- higher pipeline income

partially offset by:

- higher unit operating costs, due primarily to increased energy costs
- lower commodity marketing income

Nine Months

Earnings from Husky's midstream business segment were $139 million in the first nine months of 2003, up $26 million compared with $113 million in the same period in 2002. The increase in midstream earnings in the first nine months of 2003 was due to the following:

- higher upgrading netbacks and sales of synthetic crude oil
- higher pipeline and cogeneration income

partially offset by:

- higher upgrading operating costs
- lower commodity marketing income

Upgrading

		Three months ended September 30		Nine months ended September 30	
		2003	2002	**2003**	2002
Gross margin		**$ 75**	$ 41	**$ 235**	$ 165
Operating costs		**50**	33	**160**	107
Other expenses (recoveries)		**(2)**	(1)	**(4)**	(4)
DD&A		**5**	4	**15**	13
Income taxes		**7**	3	**11**	15
Earnings		**$ 15**	$ 2	**$ 53**	$ 34
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**74.9**	53.1	**73.3**	62.8
Synthetic crude oil sales	*(mbbls/day)*	**66.0**	47.3	**64.0**	56.5
Upgrading differential	*($/bbl)*	**11.91**	9.92	**12.76**	9.92
Unit margin	*($/bbl)*	**12.41**	9.25	**13.48**	10.65
Unit operating cost [(2)]	*($/bbl)*	**7.29**	6.79	**8.01**	6.23

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

Upgrading Earnings Variance Analysis		
Three months ended September 30, 2002	$	2
Volume		15
Differential		19
Operating costs - energy related		(16)
Operating costs - non-energy related		(1)
Other		1
DD&A		(1)
Income taxes		(4)
Three months ended September 30, 2003	**$**	**15**
Nine months ended September 30, 2002	$	34
Volume		22
Differential		48
Operating costs - energy related		(50)
Operating costs - non-energy related		(3)
DD&A		(2)
Income taxes		4
Nine months ended September 30, 2003	**$**	**53**

Infrastructure and Marketing			Three months ended September 30		Nine months ended September 30	
			2003	2002	**2003**	2002
Gross margin	- pipeline		**$ 18**	$ 12	**$ 51**	$ 42
	- other infrastructure and marketing		**29**	39	**105**	111
			47	51	**156**	153
Other expenses			**2**	3	**7**	7
DD&A			**5**	5	**15**	14
Income taxes			**14**	18	**48**	53
Earnings			**$ 26**	$ 25	**$ 86**	$ 79
Selected operating data:						
Aggregate pipeline throughput		*(mbbls/day)*	**477**	436	**478**	451

REFINED PRODUCTS

Third Quarter

Earnings from Husky's refined products business segment were $21 million in the third quarter of 2003 compared with $16 million in the same period in 2002. The increase in refined products earnings was primarily due to:

- higher margins for asphalt products
- lower light oil refined product operating costs
- higher motor fuel sales volume

partially offset by:

- lower sales margins for motor fuels

For the third quarter of 2003, retail sales per location were 6.7 percent higher and total light oil sales per location were 7.1 percent higher compared with the same period of 2002.

Nine Months

Earnings from Husky's refined products business segment were $23 million in the first nine months of 2003, compared with $33 million in the same period in 2002. The lower refined products earnings in the first nine months of 2003 were due to the following:

- lower margins for both light oil and asphalt products

partially offset by:

- higher motor fuel sales volume
- higher ancillary retail sales

For the first nine months of 2003, retail sales per location were 7.2 percent higher and total light oil sales per location were 11.0 percent higher compared with the same period of 2002.

Refined Products

			Three months ended September 30		Nine months ended September 30	
			2003	2002	**2003**	2002
Gross margin	- fuel sales		**$ 23**	$ 28	**$ 55**	$ 64
	- ancillary sales		**7**	7	**21**	19
	- asphalt sales		**25**	20	**35**	40
			55	55	**111**	123
Operating and other expenses			**14**	19	**48**	43
DD&A			**8**	9	**26**	25
Income taxes			**12**	11	**14**	22
Earnings			**$ 21**	$ 16	**$ 23**	$ 33
Selected operating data:						
Number of fuel outlets					**559**	573
Light oil sales		*(million litres/day)*	**8.5**	8.2	**8.2**	7.6
Prince George refinery throughput		*(mbbls/day)*	**8.2**	11.0	**9.9**	9.9
Asphalt sales		*(mbbls/day)*	**30.5**	30.6	**22.8**	23.0
Lloydminster refinery throughput		*(mbbls/day)*	**26.6**	25.2	**25.6**	23.4

CORPORATE

Selling and Administration Expenses

Selling and administration expenses were $28 million in the third quarter of 2003 compared with $29 million in the third quarter of 2002. In the first nine months of 2003 selling and administration expenses totalled $86 million compared with $67 million in the same period of 2002. The higher selling and administration expenses in the first nine months of 2003 were related to higher staff levels and compensation costs.

Interest Expense

Interest expense, net of interest income and interest capitalized, was $16 million in the third quarter of 2003 compared with $28 million in the third quarter of 2002. Interest capitalized in the third quarter of 2003 amounted to $15 million compared with $7 million for the same period of 2002. Higher capitalization of interest in 2003 related to the progress of the White Rose oil field development project. Interest income was $2 million higher in the third quarter of 2003 compared with the same quarter in 2002.

Foreign Exchange

Foreign exchange recorded in respect of cash transactions was a loss of $3 million in the third quarter of 2003 offset by $3 million of non-cash gains on translation of U.S. denominated monetary items. This compares with $2 million cash gain and $77 million non-cash loss on translation of U.S. denominated long-term debt in the third quarter of 2002.

Income Taxes

Husky's tax provision in the third quarter of 2003 reflects the higher pre-tax earnings. The current tax provision in the third quarter was $35 million, approximately half of which was related to income from the Wenchang operation.

Sensitivity Analysis

The following table shows the annual effect on net earnings and cash flow of changes in certain key variables. The analysis is based on business conditions and production volumes during the third quarter of 2003. Each separate item in the sensitivity analysis assumes the others are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

Item	*Increase*	*Effect on Pre-tax Cash Flow*		*Effect on Net Earnings*	
		($ millions)	*($/share)*[(4)]	*($ millions)*	*($/share)*[(4)]
WTI benchmark crude oil price					
Excluding hedges	*U.S. $1.00/bbl*	90	0.21	60	0.14
Including hedges	*U.S. $1.00/bbl*	47	0.11	30	0.07
NYMEX benchmark natural gas price [(1)]					
Excluding hedges	*U.S. $0.20/mmbtu*	33	0.08	20	0.05
Including hedges	*U.S. $0.20/mmbtu*	9	0.02	3	0.01
Light/heavy crude oil differential [(2)]	*Cdn. $1.00/bbl*	(23)	(0.06)	(15)	(0.03)
Light oil margins	*Cdn. $0.005/litre*	16	0.04	10	0.02
Asphalt margins	*Cdn. $1.00/bbl*	11	0.03	7	0.02
Exchange rate (U.S. $ per Cdn. $) [(3)]					
Including hedges	*U.S. $0.01*	(45)	(0.11)	(30)	(0.07)

(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. $ denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $9 million in net earnings based on September 30, 2003 U.S. $ denominated debt levels.
(4) Based on September 30, 2003 common shares outstanding of 421.0 million.

Liquidity and Capital Resources

SUMMARY

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Cash flow from operating activities	**$ 619**	$ 450	**$ 2,044**	$ 1,305
Cash flow from financing activities	**(26)**	(203)	**(402)**	(79)
Cash flow from investing activities	**(360)**	(279)	**(1,218)**	(1,086)
Increase (decrease) in cash and cash equivalents	**$ 233**	$ (32)	**$ 424**	$ 140

INVESTING ACTIVITIES

During the first nine months of 2003 cash flow available for investing totalled $1.6 billion compared with $1.2 billion in the same period in 2002.

Capital expenditures during the first nine months of 2003 amounted to $1.3 billion compared to $1.2 billion in the first nine months of 2002.

Capital Expenditures				
	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Upstream				
Exploration				
Western Canada	**$ 53**	$ 47	**$ 238**	$ 206
East Coast Canada	**21**	26	**24**	41
International	**9**	1	**21**	2
	83	74	**283**	249
Development				
Western Canada	**219**	160	**589**	502
East Coast Canada	**148**	143	**339**	320
International	**-**	24	**-**	65
	367	327	**928**	887
	450	401	**1,211**	1,136
Midstream				
Upgrader	**5**	9	**15**	30
Infrastructure and marketing	**5**	2	**10**	12
	10	11	**25**	42
Refined Products	**11**	9	**28**	22
Corporate	**5**	5	**14**	13
	$ 476	$ 426	**$ 1,278**	$ 1,213

Upstream

During the first nine months of 2003 capital expenditures for exploration and development in Western Canada totalled $827 million compared with $708 million during the same period in 2002.

Total development spending in Western Canada during the first nine months of 2003 amounted to $589 million compared with $502 million during the same period in 2002. In the first nine months of 2003 development expenditures were directed to the following areas:

- Alberta northwest plains area, $156 million for shallow natural gas drilling, completions and installation of facilities in the Boyer/Cherpeta districts.
- Lloydminster heavy oil area, $181 million for continued exploitation and optimization including work on the second stage of the Bolney/Celtic thermal project, which was on stream in October.
- East central and southern Alberta and southeastern Saskatchewan, $167 million primarily for in-fill drilling, facilities optimization, selective acquisitions and further development of the Shackleton/Lacadena natural gas project in southeastern Saskatchewan. During the first nine months of 2003, 82 net wells were drilled and completed in the Shackleton area.
- Alberta foothills area, $85 million for facilities optimization and in-fill drilling at major natural gas properties.

Exploration expenditures in the Western Canada Sedimentary Basin in the first nine months of 2003 amounted to $238 million compared with $206 million in the first nine months of 2002. The primary exploration targets were natural gas prospects in the Alberta foothills as well as step-out drilling throughout Husky's properties in the basin. In addition, spending during the first nine months of 2003 on the oilsands projects at Kearl and Tucker, Alberta amounted to $32 million.

Capital expenditures at Husky's White Rose oil field development offshore Newfoundland amounted to $326 million in the first nine months of 2003 compared with $316 million in the same period in 2002. Capital expenditures with respect of the Terra Nova oil field amounted to $13 million in the first nine months of 2003 compared with $19 million in the same period in 2002.

Exploration spending in the South China Sea amounted to $21 million in the first nine months of 2003 compared with $2 million in the same period in 2002.

Wells Drilled [1]									
		Three months ended September 30				Nine months ended September 30			
		2003		2002		**2003**		2002	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Western Canada									
Exploration	Oil	**4**	**4**	6	6	**9**	**8**	18	17
	Gas	**11**	**11**	17	16	**102**	**92**	124	117
	Dry	**-**	**-**	2	2	**21**	**20**	12	12
		15	**15**	25	24	**132**	**120**	154	146
Development	Oil	**213**	**202**	197	190	**400**	**374**	369	346
	Gas	**113**	**107**	79	67	**399**	**381**	319	293
	Dry	**15**	**14**	16	14	**55**	**52**	41	38
		341	**323**	292	271	**854**	**807**	729	677
		356	**338**	317	295	**986**	**927**	883	823

[1] *Excludes stratigraphic test wells.*

Midstream

In the first nine months of 2003 capital expenditures at the Husky Lloydminster Upgrader amounted to $15 million compared with $30 million in the same period in 2002. Spending was primarily directed toward the continuing optimization of the plant. Spending on midstream infrastructure amounted to $10 million in the first nine months of 2003 compared with $12 million in the same period of 2002, primarily for pipeline improvements.

Refined Products

Capital expenditures in the first nine months of 2003 amounted to $28 million for the refined products segment compared with $22 million in the first nine months of 2002. During 2003, $17 million was spent on marketing outlet construction and improvements, $8 million on refinery improvements and the balance on expanding distribution facilities.

FINANCING ACTIVITIES

At September 30, 2003 Husky's debt, net of cash and cash equivalents, was $1.2 billion compared with $2.1 billion at December 31, 2002, a reduction of $834 million. The reduction in Husky's net debt was comprised of repayments totalling $156 million, foreign exchange adjustments at September 30, 2003 totalling $254 million and an increase in cash and cash equivalents of $424 million.

Husky declared a dividend of $0.10 per share and a special dividend of $1.00 per share both payable on October 1, 2003 to shareholders of record on August 29, 2003. Total dividends recorded in the first nine months of 2003 amounted to $538 million compared with $113 million in the same period of 2002.

At September 30, 2003 there were no drawings under Husky's $930 million long-term credit facilities.

Common Share Information

(thousands of shares, except per share amounts)		Nine months ended September 30 2003	Year ended December 31 2002
Share price (1)	High	**$ 20.95**	$ 17.98
	Low	**$ 16.03**	$ 14.00
	Close at end of period	**$ 20.50**	$ 16.47
Average daily trading volume		**416**	463
Weighted average number of common shares outstanding			
	Basic	**418,816**	417,425
	Diluted	**420,781**	419,334
Number of common shares outstanding at end of period		**421,014**	417,874

(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.*

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

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

- ***changes in general economic, market and business conditions;***
- ***fluctuations in supply and demand for our products;***
- ***fluctuations in commodity prices;***
- ***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 currency exchange rates;***
- ***political and economic developments, expropriation, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which we operate;***
- ***our ability to receive timely regulatory approvals;***
- ***the integrity and reliability of our capital assets;***
- ***the cumulative impact of other resource development projects;***
- ***the accuracy of our reserve estimates, production estimates and production levels and our success at exploration and development drilling and related activities;***
- ***the maintenance of satisfactory relationships with unions, employee associations, joint venturers and partners;***
- ***competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy;***
- ***the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures;***
- ***actions by governmental authorities, including changes in environmental and other regulations;***
- ***the ability and willingness of parties with whom we have material relationships to fulfill their obligations to us; 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.***

We caution that the foregoing list of important factors is not exhaustive. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements.

CONSOLIDATED BALANCE SHEETS

(millions of dollars)	**September 30 2003**	December 31 2002
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 730**	$ 306
Accounts receivable	**768**	572
Inventories	**248**	243
Prepaid expenses	**67**	23
	1,813	1,144
Property, plant and equipment - (full cost accounting)	**15,516**	14,450
Less accumulated depletion, depreciation and amortization	**5,711**	5,103
	9,805	9,347
Other assets	**98**	84
	$ 11,716	$ 10,575
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 1,478**	$ 811
Long-term debt due within one year *(note 4)*	**464**	421
	1,942	1,232
Long-term debt *(note 4)*	**1,511**	1,964
Site restoration and other long-term liabilities	**314**	249
Future income taxes *(note 6)*	**2,285**	2,003
Shareholders' equity		
Capital securities and accrued return	**305**	364
Common shares *(note 5)*	**3,444**	3,406
Retained earnings	**1,915**	1,357
	5,664	5,127
	$ 11,716	$ 10,575
Commitments and Contingencies *(note 7)*		
Common shares outstanding *(millions)* *(note 5)*	**421.0**	417.9

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

CONSOLIDATED STATEMENTS OF EARNINGS

(unaudited)

(millions of dollars, except per share amounts)	Three months ended September 30 **2003**	Three months ended September 30 2002	Nine months ended September 30 **2003**	Nine months ended September 30 2002
Sales and operating revenues, net of royalties	**$ 1,871**	$ 1,669	**$ 5,858**	$ 4,687
Costs and expenses				
Cost of sales and operating expenses	**1,182**	1,000	**3,660**	3,008
Selling and administration expenses	**28**	29	**86**	67
Depletion, depreciation and amortization	**254**	239	**765**	683
Interest - net *(note 4)*	**16**	28	**57**	79
Foreign exchange *(note 4)*	**-**	75	**(172)**	18
Other - net	**-**	1	**2**	-
	1,480	1,372	**4,398**	3,855
Earnings before income taxes	**391**	297	**1,460**	832
Income taxes *(note 6)*				
Current	**35**	26	**125**	60
Future	**113**	98	**259**	210
	148	124	**384**	270
Net earnings	**$ 243**	$ 173	**$ 1,076**	$ 562
Earnings per share *(note 9)*				
Basic	**$ 0.55**	$ 0.38	**$ 2.61**	$ 1.31
Diluted	**$ 0.54**	$ 0.38	**$ 2.60**	$ 1.31
Weighted average number of common shares outstanding *(millions) (note 9)*				
Basic	**419.7**	417.5	**418.8**	417.3
Diluted	**422.0**	419.1	**420.8**	419.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(unaudited)

(millions of dollars)	Three months ended September 30 **2003**	Three months ended September 30 2002	Nine months ended September 30 **2003**	Nine months ended September 30 2002
Beginning of period	**$ 2,148**	$ 1,037	**$ 1,357**	$ 722
Net earnings	**243**	173	**1,076**	562
Dividends on common shares	**(463)**	(38)	**(538)**	(113)
Return on capital securities (net of related taxes and foreign exchange)	**(13)**	(14)	**20**	(13)
End of period	**$ 1,915**	$ 1,158	**$ 1,915**	$ 1,158

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

(millions of dollars)	Three months ended September 30 2003	Three months ended September 30 2002	Nine months ended September 30 2003	Nine months ended September 30 2002
Operating activities				
Net earnings	**$ 243**	$ 173	**$ 1,076**	$ 562
Items not affecting cash				
Depletion, depreciation and amortization	**254**	239	**765**	683
Future income taxes	**113**	98	**259**	210
Foreign exchange - non-cash	**(3)**	77	**(205)**	7
Other	**(3)**	3	**(4)**	(1)
Cash flow from operations	**604**	590	**1,891**	1,461
Change in non-cash working capital *(note 8)*	**15**	(140)	**153**	(156)
Cash flow - operating activities	**619**	450	**2,044**	1,305
Financing activities				
Bank operating loans financing - net	-	-	-	(100)
Long-term debt issue	-	-	-	972
Long-term debt repayment	**(16)**	(9)	**(156)**	(655)
Return on capital securities payment	**(14)**	(15)	**(29)**	(31)
Debt issue costs	**-**	(2)	-	(9)
Proceeds from exercise of stock options	**29**	1	**38**	5
Proceeds from interest swaps monetization	**-**	-	**44**	-
Dividends on common shares	**(463)**	(38)	**(538)**	(113)
Change in non-cash working capital *(note 8)*	**438**	(140)	**239**	(148)
Cash flow - financing activities	**(26)**	(203)	**(402)**	(79)
Available for investing	**593**	247	**1,642**	1,226
Investing activities				
Capital expenditures	**(476)**	(426)	**(1,278)**	(1,213)
Asset sales	**3**	65	**52**	82
Other	**(1)**	(8)	**3**	(18)
Change in non-cash working capital *(note 8)*	**114**	90	**5**	63
Cash flow - investing activities	**(360)**	(279)	**(1,218)**	(1,086)
Increase (decrease) in cash and cash equivalents	**233**	(32)	**424**	140
Cash and cash equivalents at beginning of period	**497**	172	**306**	-
Cash and cash equivalents at end of period	**$ 730**	$ 140	**$ 730**	$ 140

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Nine months ended September 30, 2003 *(unaudited)*

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

Note 1 Segmented Financial Information

			Midstream									
	Upstream		Upgrading		Infrastructure and Marketing		**Refined Products**		**Corporate and Eliminations** [1]		**Total**	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Three months ended September 30												
Sales and operating revenues, net of royalties	**$ 740**	$ 738	**$ 252**	$ 192	**$1,170**	$ 953	**$ 431**	$ 431	**$ (722)**	$ (645)	**$ 1,871**	$ 1,669
Costs and expenses												
Operating, cost of sales, selling and general	**199**	189	**225**	183	**1,125**	905	**390**	395	**(729)**	(642)	**1,210**	1,030
Depletion, depreciation and amortization	**229**	218	**5**	4	**5**	5	**8**	9	**7**	3	**254**	239
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**16**	28	**16**	28
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	75	**-**	75
	428	407	**230**	187	**1,130**	910	**398**	404	**(706)**	(536)	**1,480**	1,372
Earnings (loss) before income taxes	**312**	331	**22**	5	**40**	43	**33**	27	**(16)**	(109)	**391**	297
Current income taxes	**13**	8	**-**	1	**4**	13	**14**	4	**4**	-	**35**	26
Future income taxes	**91**	117	**7**	2	**10**	5	**(2)**	7	**7**	(33)	**113**	98
Net earnings (loss)	**$ 208**	$ 206	**$ 15**	$ 2	**$ 26**	$ 25	**$ 21**	$ 16	**$ (27)**	$ (76)	**$ 243**	$ 173
Nine months ended September 30												
Sales and operating revenues, net of royalties	**$2,464**	$1,884	**$ 784**	$ 608	**$3,807**	$2,863	**$1,167**	$ 984	**$ (2,364)**	$ (1,652)	**$ 5,858**	$ 4,687
Costs and expenses												
Operating, cost of sales, selling and general	**634**	523	**705**	546	**3,658**	2,717	**1,104**	904	**(2,353)**	(1,615)	**3,748**	3,075
Depletion, depreciation and amortization	**691**	620	**15**	13	**15**	14	**26**	25	**18**	11	**765**	683
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**57**	79	**57**	79
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(172)**	18	**(172)**	18
	1,325	1,143	**720**	559	**3,673**	2,731	**1,130**	929	**(2,450)**	(1,507)	**4,398**	3,855
Earnings (loss) before income taxes	**1,139**	741	**64**	49	**134**	132	**37**	55	**86**	(145)	**1,460**	832
Current income taxes	**90**	29	**-**	1	**5**	25	**22**	5	**8**	-	**125**	60
Future income taxes	**175**	234	**11**	14	**43**	28	**(8)**	17	**38**	(83)	**259**	210
Net earnings (loss)	**$ 874**	$ 478	**$ 53**	$ 34	**$ 86**	$ 79	**$ 23**	$ 33	**$ 40**	$ (62)	**$ 1,076**	$ 562
Capital employed - As at September 30 [2]	**$6,187**	$6,027	**$ 462**	$ 343	**$ 446**	$ 428	**$ 403**	$ 360	**$ 141**	$ 176	**$ 7,639**	$ 7,334
Total assets - As at September 30	**$8,834**	$8,105	**$ 654**	$ 665	**$ 792**	$ 871	**$ 585**	$ 554	**$ 851**	$ 153	**$11,716**	$ 10,348

[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.*
[2] *Capital employed is defined as short- and long-term debt and shareholders' equity.*

Note 2 Significant Accounting Polices

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, 2002. 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, 2002.

Note 3 Financial Instruments and Risk Management

Upstream Commodity Price Risk

In January and February 2003, the Company hedged crude oil averaging 85,000 bbls/day from April to December 2003 at an average fixed WTI price of U.S. $29.42/bbl. In October 2003, the Company hedged additional crude oil of 10,000 bbls/day for October to December 2003 at an average fixed WTI price of U.S. $31.36/bbl. In addition, the Company executed a put option program in February 2003 for approximately 3.7 mmbbls from July to December 2003 at a strike price of U.S. $27.00/bbl. The cost of the put option program of U.S. $6.1 million was deferred and is being amortized over the term of the options.

The Company hedged crude oil averaging 80,000 bbls/day from January to December 2004 at an average fixed WTI price of U.S. $27.35/bbl.

In February and May 2003, the Company hedged 230 mmcf/day of natural gas for April to June 2003, 240 mmcf/day for July to October 2003 and 100 mmcf/day for November and December 2003 at an average NYMEX price of U.S. $5.33/mcf.

Power Consumption Price Risk

In September 2003, the Company hedged power consumption of 175,680 MWh from January to December 2004 at a fixed price of $46.25/MWh.

Foreign Currency Rate Risk

In the first nine months of 2003, the Company entered into the following cross currency debt swaps:

Debt	Swap Amount *(millions)*	Swap Maturity	Interest Rate	Canadian Equivalent *(millions)*
6.875% notes	U.S. $150	November 15, 2003	8.50%	$229
7.125% notes	U.S. $150	November 15, 2006	8.74%	$218
6.25% notes	U.S. $150	June 15, 2012	7.41%	$212

Interest Rate Risk

The Company has interest rate swap arrangements whereby the fixed interest rate coupon on certain debt has been swapped to floating rates with the following terms as at September 30, 2003:

Debt	Swap Amount *(millions)*	Swap Maturity	Swap Rate *(percent)*
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps

During the first nine months of 2003, the Company unwound the following interest rate swaps:

Debt	Swap Amount *(millions)*	Swap Maturity	Gross Proceeds *(millions)*
6.875% notes	U.S. $35	November 15, 2003	U.S. $2
7.125% notes	U.S. $150	November 15, 2006	U.S. $12
6.25% senior notes	U.S. $150	June 15, 2012	U.S. $16

The proceeds have been deferred and are being amortized over the term of the debt.

Sale of Accounts Receivable

The Company terminated its agreement to sell net trade receivables of up to $200 million on a continual basis on March 31, 2003.

Note 4 Long-term Debt

			Maturity	**Sept. 30 2003**	Dec. 31 2002
Long-term debt					
6.25% notes	*-2003 & 2002*	*U.S. $400*	2012	**$ 540**	$ 632
6.875% notes	*-2003 & 2002*	*U.S. $150*	2003	**203**	237
7.125% notes	*-2003 & 2002*	*U.S. $150*	2006	**203**	237
7.55% debentures	*-2003 & 2002*	*U.S. $200*	2016	**270**	316
8.45% senior secured bonds	*-2003*	*U.S. $145*			
	-2002	*U.S. $162*	2004-12	**196**	256
Private placement notes	*-2003*	*U.S. $47*			
	-2002	*U.S. $68*	2003-5	**63**	107
Medium-term notes			2004-9	**500**	600
Total long-term debt				**1,975**	2,385
Amount due within one year				**(464)**	(421)
				$ 1,511	$ 1,964

At September 30, 2003, the Company did not have any borrowings under the Company's $830 million syndicated credit facility or its $100 million credit facility. Interest rates under the syndicated credit facility vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected, credit ratings assigned by certain rating agencies to the Company's senior unsecured debt and whether the facility is revolving or non-revolving. The $100 million credit facility has substantially the same terms as the syndicated credit facility.

Interest - net consisted of:

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Long-term debt	**$ 33**	$ 35	**$ 99**	$ 95
Short-term debt	**-**	-	**1**	2
	33	35	**100**	97
Amount capitalized	**(15)**	(7)	**(37)**	(17)
	18	28	**63**	80
Interest income	**(2)**	-	**(6)**	(1)
	$ 16	$ 28	**$ 57**	$ 79

Foreign exchange consisted of:

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ (5)**	$ 77	**$ (255)**	7
Cross currency swaps	**2**	-	**50**	-
Other losses (gains)	**3**	(2)	**33**	11
	$ -	$ 75	**$ (172)**	$ 18

Note 5 Share Capital

The Company's authorized share capital consists of an unlimited number of no par value common and preferred shares. Changes to issued share capital were as follows:

	Nine months ended September 30			
	2003		2002	
	Number of Common Shares	Amount	Number of Common Shares	Amount
Balance at beginning of period	417,873,601	$ 3,406	416,878,093	$ 3,397
Exercised for cash - options and warrants	3,140,762	38	706,291	5
Balance at September 30	**421,014,363**	**$ 3,444**	417,584,384	$ 3,402

The Company follows the intrinsic value method of accounting for stock-based compensation for its fixed stock option plan, under which compensation cost is not recognized.

The fair values of all common share options granted are estimated on the date of grant using the Modified Black-Scholes option pricing model. The weighted average fair market value of options granted during the year and the assumptions used in their determination are as noted below:

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Weighted average fair market value per option	**$ -**	$ -	**$ 3.76**	$ 5.99
Risk-free interest rate *(percent)*	**-**	-	**3.9**	3.5
Volatility *(percent)*	**-**	-	**24**	45
Expected life *(years)*	**-**	-	**5**	5
Expected annual dividend per share	**$ -**	$ -	**$ 0.36**	$ 0.36

A downward adjustment of $0.82 to the exercise price of all outstanding stock options effective September 3, 2003 was made pursuant to the terms of the stock option plan under which the options were issued as a result of the special $1.00 per share dividend that was declared on July 23, 2003. The fair values of all common shares granted were revalued at the modification date using the Modified Black-Scholes option pricing model. The weighted average fair market value of outstanding stock options as at September 3, 2003 and the assumptions used in their determination are as noted below:

Weighted average fair market value per option	**$ 7.14**
Risk-free interest rate *(percent)*	**2.8**
Volatility *(percent)*	**20**
Expected life *(years)*	**2.3**
Expected annual dividend per share	**$ 0.40**

If the Company applied the fair value method, additional compensation cost of $3.9 million for all options granted would be recognized over the vesting period due to the modification of all options outstanding. For the three months and nine months ended September 30, 2003, additional compensation cost of $3.5 million would be recognized.

If the Company applied the fair value method at the grant dates for options granted after January 1, 2002 and also to all options granted, the Company's net earnings and earnings per share would have been as follows:

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Compensation cost - options granted after January 1, 2002	**$ -**	$ -	**$ 1**	$ -
Compensation cost - all options granted	**$ 6**	$ 3	**$ 13**	$ 9
Net earnings available to common shareholders				
As reported	**$ 230**	$ 159	**$ 1,095**	$ 548
Options granted after January 1, 2002	**$ 230**	$ 159	**$ 1,094**	$ 548
All options granted	**$ 224**	$ 156	**$ 1,082**	$ 539
Weighted average number of common shares outstanding *(millions)*				
Basic	**419.7**	417.5	**418.8**	417.3
Diluted	**422.0**	419.1	**420.8**	419.3
Basic earnings per share				
As reported	**$ 0.55**	$ 0.38	**$ 2.61**	$ 1.31
Options granted after January 1, 2002	**$ 0.55**	$ 0.38	**$ 2.61**	$ 1.31
All options granted	**$ 0.53**	$ 0.37	**$ 2.58**	$ 1.29
Diluted earnings per share				
As reported	**$ 0.54**	$ 0.38	**$ 2.60**	$ 1.31
Options granted after January 1, 2002	**$ 0.54**	$ 0.38	**$ 2.60**	$ 1.31
All options granted	**$ 0.53**	$ 0.37	**$ 2.57**	$ 1.29

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

	Nine months ended September 30			
	2003		2002	
Fixed Options	Number of Shares *(thousands)*	Weighted Average Exercise Prices	Number of Shares *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	7,920	$13.91	8,602	$13.78
Granted	326	$16.85	329	$16.32
Exercised	(2,833)	$13.62	(356)	$13.58
Forfeited	(104)	$14.60	(506)	$14.34
Outstanding, September 30	**5,309**	**$13.31**	8,069	$13.86
Options exercisable at September 30	4,444	$12.90	5,084	$13.72

At September 30, 2003, the options outstanding had exercise prices ranging from $10.34 to $16.35 with a weighted average contractual life of 2.3 years.

Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings as the Company has neither the obligation nor intention to settle amounts due through the issue of shares.

Note 6 Income Taxes

Income tax expense in the first nine months of 2003 included a non-recurring adjustment to future income taxes of $20 million resulting from a change in the Alberta corporate income tax rate. Additionally, on June 13, 2003 Bill C-48, an Act to amend the Income Tax Act (natural resources), was substantively enacted and resulted in a non-recurring tax benefit of $141 million. The resource tax changes include a change in the federal tax rate, deductibility of crown royalties and elimination of the resource allowance, to be phased in over the next five years. Income tax expense in the first nine months of 2002 included a non-recurring adjustment to future income taxes of $44 million resulting from changes to the British Columbia and Alberta corporate income tax rates, a reduction in the federal corporate income tax rate for non-resource income and the recognition of additional tax deductions relating to foreign exchange losses of prior years.

Note 7 Commitments and Contingencies

The Company has awarded various contracts for the construction of the floating production, storage and offloading vessel and several other components of the White Rose development project with expected completion dates in 2005. The Company's share of the total value of contractual obligations at September 30, 2003 was $1.1 billion. As at September 30, 2003, the Company had spent $574 million on these contracts.

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

Note 8 Cash Flows - Change in Non-cash Working Capital

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
a) Changes in non-cash working capital were as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 98**	$ (276)	**$ (195)**	$ (314)
Inventories	**5**	3	**(5)**	(15)
Prepaid expenses	**(38)**	(10)	**(45)**	(8)
Accounts payable and accrued liabilities	**502**	93	**642**	96
Change in non-cash working capital	**567**	(190)	**397**	(241)
Relating to:				
Financing activities	**438**	(140)	**239**	(148)
Investing activities	**114**	90	**5**	63
Operating activities	**$ 15**	$ (140)	**$ 153**	$ (156)
b) Other cash flow information:				
Cash taxes paid	**$ 2**	$ 6	**$ 67**	$ 20
Cash interest paid	**$ 17**	$ 24	**$ 85**	$ 94

Note 9 Net Earnings Per Common Share

	Three months ended September 30		Nine months ended September 30	
	2003	2002	**2003**	2002
Net earnings	**$ 243**	$ 173	**$ 1,076**	$ 562
Return on capital securities (net of related taxes and foreign exchange)	**(13)**	(14)	**19**	(14)
Net earnings available to common shareholders	**$ 230**	$ 159	**$ 1,095**	$ 548
Weighted average number of common shares outstanding - Basic *(millions)*	**419.7**	417.5	**418.8**	417.3
Effect of dilutive stock options and warrants	**2.3**	1.6	**2.0**	2.0
Weighted average number of common shares outstanding - Diluted *(millions)*	**422.0**	419.1	**420.8**	419.3
Net earnings				
Per share - Basic	**$ 0.55**	$ 0.38	**$ 2.61**	$ 1.31
- Diluted	**$ 0.54**	$ 0.38	**$ 2.60**	$ 1.31

Note 10 Acquisition of Marathon Canada

On August 20, 2003, the Company entered into an agreement which subsequently closed October 1, 2003 to acquire all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. for a purchase price of U.S. $588 million. In a separate transaction, the Company has agreed to sell certain of the Marathon Canada oil and gas properties to a third party for a sale price of U.S. $320 million which also closed October 1, 2003.

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
MWh	megawatt hour
NGL	natural gas liquids
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
LIBOR	London Interbank Offered Rate
CDOR	Certificate of Deposit Offered Rate
hectare	1 hectare is equal to 2.47 acres
Capital Employed	Short- and long-term debt and shareholders' equity
Capital Expenditures	Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets
Cash Flow from Operations	Earnings from operations plus non-cash charges before change in non-cash working capital
Equity	Capital securities and accrued return, shares and retained earnings
Net Debt	Total debt net of cash and cash equivalents
Total Debt	Long-term debt including current portion and bank operating loans

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

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

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