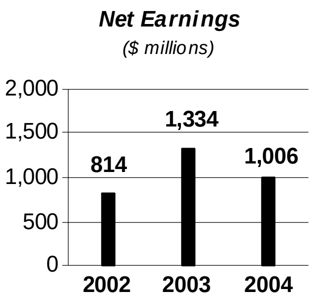
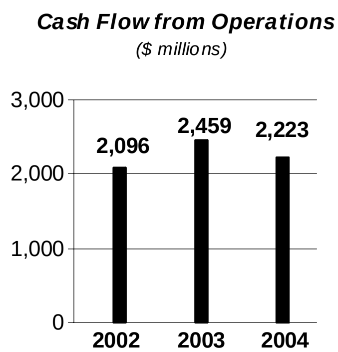
HUSKY ENERGY REPORTS 2004 FOURTH QUARTER RESULTS



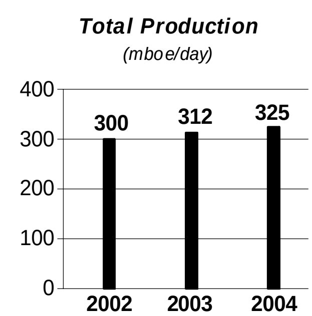
Calgary, Alberta - Husky Energy Inc. had net earnings of $1.01 billion or $2.36 per share (diluted) in 2004, compared with $1.33 billion or $3.25 per share (diluted) in 2003. Cash flow from operations in 2004 was $2.22 billion or $5.16 per share (diluted), compared with $2.46 billion or $5.76 per share (diluted) in 2003. The difference in the financial performance between 2004 and 2003 is primarily due to the Company's hedging program, the strong Canadian dollar relative to the U.S. dollar, and one-time non-recurring tax rate reductions.

	Year ended December 31	
($ million) (loss (gain))	**2004**	2003
Net earnings	$1,006	$1,334
Net hedging impact	376	17
Net foreign exchange	(80)	(174)
Non-recurring tax rate adjustments	(40)	(161)
	$1,262	$1,016



"Husky achieved strong operational and financial results for the year and made good progress on its major projects," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "Notwithstanding higher commodity prices, the financial results were negatively impacted by our crude oil hedging program, which expired at the end of 2004 and by a stronger Canadian dollar, which reduced the benefit of higher oil prices."

Production for the year averaged 325,000 barrels of oil equivalent per day, compared with 312,500 barrels of oil equivalent per day during 2003. Total crude oil and natural gas liquids production for 2004 was 210,100 barrels per day, compared with 210,700 barrels per day during 2003. Natural gas production was 689.2 million cubic feet per day, up 13 percent from 610.6 million cubic feet per day for 2003.



For the fourth quarter of 2004, Husky's net earnings were $218 million or $0.52 per share (diluted), compared with $236 million or $0.59 per share (diluted) in the fourth quarter of 2003. Cash flow from operations was $476 million or $1.10 per share (diluted) in the fourth quarter of 2004, compared with $568 million or $1.32 per share (diluted) in the fourth quarter of 2003.

Production for the fourth quarter of 2004 averaged 324,600 barrels of oil equivalent per day, compared with 327,000 barrels of oil equivalent per day in the fourth quarter of 2003. Total crude oil and natural gas liquids production for the fourth quarter was 208,400 barrels per day, compared with 217,700 barrels per day for the same period in 2003. Natural gas production for the fourth quarter of 2004 averaged 697.4 million cubic feet per day, compared with 655.7 million cubic feet per day for the same quarter in 2003.

Husky's proved oil and gas reserves are estimated in accordance with the regulations and guidance of the U.S. Securities and Exchange Commission ("SEC"), which, among other things, requires reserves to be evaluated using the prices in effect on the day the reserves are estimated. As a result of several market factors, prices for heavy crude oil were $12.27 per barrel on December 31, 2004 and averaged $25.91 per barrel in the fourth quarter of 2004. This reserve issue does not have an impact on the company's financial statements as the reserve estimates are calculated at $26.77 per barrel for heavy crude oil, using escalated pricing in accordance with Canadian generally accepted accounting principles. For a more complete discussion of this issue refer to "Oil and Gas Reserves" on page 13 of this news release.

Husky announced in July the commencement of its Tucker oil sands project, a 30,000 barrel per day project near Cold Lake, Alberta. The central plant facilities contract is on a lump sum basis and covers 60 percent of the total project cost. Husky expects to commission the facility in the second half of 2006. The Company also filed, in August, an application with the Alberta government for approval of its 200,000 barrel per day Sunrise oil sands project in the Athabasca region.

On Canada's East Coast, Husky continued the development of its White Rose project and is on target to achieve first oil in late 2005 or early 2006. Internationally, Husky signed a seventh petroleum contract with the China National Offshore Oil Corporation and plans to drill three wells in the South China Sea in 2005. Husky also plans to pursue its development in Indonesia, where the Company increased its interest to 100 percent in a production sharing contract in the Madura Strait, Indonesia.

Husky is proceeding with the upgrade to its Prince George oil refinery, which will allow the refinery to produce low sulphur gasoline and diesel fuel that meet the Government of Canada's new fuel specifications. Husky also commenced construction at Lloydminster, Saskatchewan of a 130 million litre per year ethanol facility to meet the growing demand for this environmentally friendly fuel additive.

In December 2004, Husky announced its 2005 capital expenditure program of $2.5 billion, with $2.1 billion allocated to the upstream segment. Upstream activities will focus on oil and natural gas exploration activities in Western Canada, in the Northwest Territories, development of heavy oil and oil sands properties in Alberta, and commissioning of the White Rose floating production, storage and offloading ("FPSO") vessel. International activities include the planned drilling of three exploratory wells and additional seismic programs in the South China Sea and East China Sea.

"We anticipate achieving first oil at our White Rose offshore oil field as well as continued growth in heavy oil and natural gas production in Western Canada," said Mr. Lau. "We will continue to be mindful of the impact of strong forecasted commodity prices and to fluctuations in the exchange rate. Husky is looking forward to having a strong year in 2005."

Highlights

Financial Summary (1)

(millions of dollars, except per share amounts and ratios)	Three months ended Dec. 31 2004	Sept. 30 2004	June 30 2004	March 31 2004	Dec. 31 2003	Sept. 30 2003	June 30 2003	March 31 2003	Year ended Dec. 31 2004	Dec. 31 2003
Sales and operating revenues, net of royalties [2]	**$ 2,018**	$ 2,191	$ 2,210	$ 2,021	$ 1,800	$ 1,871	$ 1,769	$ 2,218	**$ 8,440**	$ 7,658
Segmented earnings										
Upstream	**$ 112**	$ 161	$ 204	$ 236	$ 169	$ 215	$ 374	$ 309	**$ 713**	$ 1,067
Midstream	**77**	50	53	60	46	41	49	49	**240**	185
Refined Products	**(3)**	18	21	5	6	22	3	1	**41**	32
Corporate and eliminations	**32**	57	(39)	(38)	15	(29)	15	49	**12**	50
Net earnings	**$ 218**	$ 286	$ 239	$ 263	$ 236	$ 249	$ 441	$ 408	**$ 1,006**	$ 1,334
Per share - Basic	**$ 0.53**	$ 0.70	$ 0.54	$ 0.60	$ 0.60	$ 0.56	$ 1.09	$ 1.01	**$ 2.37**	$ 3.26
- Diluted	**0.52**	0.70	0.54	0.60	0.59	0.56	1.09	1.01	**2.36**	3.25
Dividends declared per common share	**0.12**	0.12	0.12	0.10	0.10	0.10	0.09	0.09	**0.46**	0.38
Special dividend per common share	**0.54**	-	-	-	-	1.00	-	-	**0.54**	1.00
Return on equity [3] *(percent)*	**16.2**	16.7	16.1	20.5	24.1	25.2	23.6	21.7	**16.2**	24.1
Return on average capital employed [3] *(percent)*	**12.8**	13.1	12.6	15.9	18.1	18.5	17.6	15.8	**12.8**	18.1

(1) 2003 amounts as restated. Refer to note 3 to the consolidated financial statements.
(2) The three months ended September 30, 2004, June 30, 2004 and March 31, 2004 have been reclassified for hedging losses included as a consolidated expense.
(3) Calculated for the twelve months ended for the periods shown.

Production, before Royalties

		Three months ended Dec. 31 2004	Sept. 30 2004	June 30 2004	March 31 2004	Dec. 31 2003
Crude oil & NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**32.9**	33.1	32.9	32.9	34.7
Medium crude oil		**33.7**	34.5	35.6	36.1	37.9
Heavy crude oil		**113.8**	108.8	107.4	105.6	107.8
		180.4	176.4	175.9	174.6	180.4
East Coast Canada						
Terra Nova - light crude oil		**10.1**	11.5	15.7	17.6	17.8
China						
Wenchang - light crude oil		**17.9**	20.2	20.6	19.9	19.5
		208.4	208.1	212.2	212.1	217.7
Natural gas	*(mmcf/day)*	**697.4**	700.4	685.4	673.6	655.7
Total	*(mboe/day)*	**324.6**	324.8	326.4	324.4	327.0

Fourth Quarter of 2004 Compared with the Third Quarter of 2004

Total production from our properties in Western Canada in the fourth quarter of 2004 averaged 296.6 mboe per day, up one percent from 293.1 mboe per day in the third quarter of 2004.

Natural gas production during the fourth quarter declined marginally compared with the third quarter of 2004, averaging 697.4 mmcf per day. During the fourth quarter, 40 mmcf per day of natural gas production was added while natural reservoir declines amounted to 43 mmcf per day.

Total crude oil and NGL production in Western Canada in the fourth quarter of 2004 was 180.4 mbbls per day, up two percent from 176.4 mbbls per day in the previous quarter. The higher crude oil production during the fourth quarter of 2004 was due to the addition of 12.9 mbbls per day resulting mainly from higher heavy crude oil primary production in the Lloydminster area, partially offset by natural reservoir declines.

Our share of production from the Terra Nova oil field averaged 10.1 mbbls of crude oil per day in the fourth quarter of 2004. Production operations at Terra Nova were interrupted throughout the fourth quarter due to operational issues.

In the South China Sea, our share of production from the Wenchang oil field averaged 17.9 mbbls of crude oil per day during the fourth quarter of 2004, an 11 percent decrease from 20.2 mbbls per day in the previous quarter due to natural reservoir declines and remedial operations conducted on several wells in December 2004.

Exploration

Western Canada

During the fourth quarter of 2004, 72 net exploratory wells were drilled in the Western Canada Sedimentary Basin, resulting in 23 net oil wells and 46 net natural gas wells.

During the fourth quarter, four natural gas wells were completed at Reilly in the Alberta foothills. These wells were tested at total rates between 10 and 15 mmcf per day per well. Our average working interest in these wells is 40 percent.

In the Lynx/Copton area in the Alberta foothills we drilled two natural gas wells that will be completed and on stream in the first quarter of 2005. Our working interest is 70 percent in both wells.

At Moose Mountain, also in the Alberta foothills, we are in the process of completing a natural gas discovery with a working interest of 43.5 percent.

In the northern areas of Alberta and British Columbia and the Deep Basin area in Alberta, our winter drilling program is underway and we expect to have 10 drilling rigs active during the first quarter of 2005. A significant part of our program will focus in the Ekwan/Bivouac/Titan areas in northeastern British Columbia and will continue our successful Jean Marie/Mississippian exploration program from last year.

Northwest Territories

During winter 2005, we will participate in one exploration well in the central Mackenzie region and complete the Summit Creek discovery that was drilled during the winter in 2004.

East Coast Canada

During the fourth quarter of 2004, we acquired three new exploration licenses in the Jeanne d'Arc Basin comprising 560,000 acres and entailing a $47 million work commitment.

Offshore China

During the fourth quarter of 2004, tenders were requested for shallow and deep water drilling rigs to drill three exploration wells in 2005. The rig bids are currently being evaluated.

Major Projects

Oil Sands

Tucker, Alberta

At Tucker, construction of the well pads is progressing and water supply wells confirmed adequate water capacity. During the fourth quarter, major equipment orders were placed for the new facilities and drilling rigs were secured.

Sunrise, Alberta

During the fourth quarter of 2004, review of the project application by the Alberta Energy and Utilities Board and Alberta Environment progressed and we expect to receive queries early in 2005. We have now finalized plans for a 40-well program for winter 2005.

White Rose

At the White Rose oil field, offshore Newfoundland and Labrador, the first well in the central glory hole was drilled, a water injection well that will augment the pressure in the reservoir. A total of six development wells (one production well, one gas injection well and four water injection wells) have been drilled to date. Currently construction is underway on the production and gas injection flowlines that will connect the subsea well head equipment to the floating production, storage and offloading vessel.

Commissioning of the topsides facilities on the floating production, storage and offloading vessel is progressing.

Two shuttle tankers that will be leased are currently being constructed in Korea.

Husky Lloydminster Upgrader

The major debottleneck program underway at the Husky Lloydminster Upgrader has now identified various projects to enable throughput to increase from 77,000 barrels per day to 82,000 barrels per day. The debottleneck program is expected to be completed by mid 2006.

Lloydminster Ethanol Plant

During the fourth quarter of 2004, detailed engineering design phase work progressed and site preparation was completed. The plant is expected to be completed in early 2006 and will have a design rate capacity to produce 130 million litres per year.

Prince George Refinery

The Prince George refinery is currently undergoing a major upgrade that will reduce the sulphur content in gasoline and diesel fuels to meet new Government of Canada fuel specifications and increase overall capacity by 10 percent. We currently expect the gasoline desulphurization work to be complete by August 2005 and the diesel desulphurization work to be complete by March 2006.

Western Canada

During the fourth quarter of 2004, we commissioned the Western Canada Select project at our Hardisty terminal. This will combine crude oil production of four major producers to produce a new heavy sour crude blend. During December we shipped a total 2.1 million barrels of oil to markets in the United States.

Production versus 2004 Forecast

		Year ended Dec. 31 2004	Forecast 2004
Crude oil & NGL	*(mbbls/day)*		
Light crude oil & NGL		66.2	67-76
Medium crude oil		35.0	35-40
Heavy crude oil		108.9	105-115
		210.1	207-231
Natural gas	*(mmcf/day)*	689.2	670-710
Total barrels of oil equivalent	*(mboe/day)*	325.0	320-350

Average Benchmark Prices and U.S. Exchange Rate

		Three months ended				
		Dec. 31 2004	Sept. 30 2004	June 30 2004	March 31 2004	Dec. 31 2003
WTI crude oil [1]	*(U.S. $/bbl)*	**$ 48.28**	$ 43.88	$ 38.32	$ 35.15	$ 31.18
Canadian par light crude 0.3% sulphur	*($/bbl)*	**58.01**	56.61	50.99	46.00	39.95
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**7.11**	5.76	5.97	5.69	4.58
NIT natural gas	*($/GJ)*	**6.72**	6.32	6.45	6.26	5.30
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**19.82**	12.86	11.82	10.12	10.37
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.819**	0.765	0.736	0.759	0.760

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

SENSITIVITY ANALYSIS

The following table is indicative of the relative effect of changes in certain key variables on pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the fourth quarter of 2004. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

Item	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
		($ millions)	*($/share)* [4]	*($ millions)*	*($/share)* [4]
WTI benchmark crude oil price					
Excluding commodity hedges	*U.S. $1.00/bbl*	81	0.19	55	0.13
Including commodity hedges	*U.S. $1.00/bbl*	42	0.10	28	0.07
NYMEX benchmark natural gas price [1]					
Excluding commodity hedges	*U.S. $0.20/mmbtu*	38	0.09	25	0.06
Including commodity hedges	*U.S. $0.20/mmbtu*	38	0.09	25	0.06
Light/heavy crude oil differential [2]	*Cdn. $1.00/bbl*	(33)	(0.08)	(22)	(0.05)
Light oil margins	*Cdn. $0.005/litre*	15	0.04	10	0.02
Asphalt margins	*Cdn. $1.00/bbl*	8	0.02	5	0.01
Exchange rate (U.S. $ / Cdn. $) [3]					
Including commodity hedges	*U.S. $0.01*	(50)	(0.12)	(35)	(0.08)

(1) *Includes decrease in earnings related to natural gas consumption.*
(2) *Includes impact of upstream and upgrading operations only.*
(3) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $10 million in net earnings based on December 31, 2004 U.S. dollar denominated debt levels.*
(4) *Based on December 31, 2004 common shares outstanding of 423.7 million.*

Results of Operations

UPSTREAM

Upstream Earnings Summary [1]

(millions of dollars)	Three months ended December 31		Year ended December 31	
	2004	2003	**2004**	2003
Gross revenues	**$ 1,099**	$ 859	**$ 4,392**	$ 3,796
Royalties	**174**	126	**711**	584
Hedging	**203**	11	**561**	26
Net revenues	**722**	722	**3,120**	3,186
Operating and administrative expenses	**247**	227	**967**	873
Depletion, depreciation and amortization	**283**	263	**1,077**	918
Income taxes	**80**	63	**363**	328
Earnings	**$ 112**	$ 169	**$ 713**	$ 1,067

(1) *2003 amounts as restated. Refer to note 3 to the consolidated financial statements.*

Fourth Quarter

Lower upstream earnings in the fourth quarter of 2004 compared with the fourth quarter of 2003 were primarily the result of the following factors:

- hedging losses of $6.79 per boe during the fourth quarter of 2004 compared with $0.37 per boe during the fourth quarter of 2003
- higher royalties during the fourth quarter of 2004 due to the higher commodity prices compared with the same period in 2003
- lower production volume of light and medium crude oil

- higher unit operating costs during the fourth quarter of 2004 resulting from increased level of field servicing compared with same period in 2003
- higher depletion, depreciation and amortization per boe due to a higher capital base in the fourth quarter of 2004
- higher income taxes

which were partially offset by:

- higher crude oil and natural gas prices
- higher production volume of heavy crude oil and natural gas

Twelve Months

Lower upstream earnings in 2004 compared with 2003 resulted from primarily the same factors as those affecting the fourth quarter of 2004.

Depletion, Depreciation and Amortization

Total depreciation, depletion and amortization expense per boe during the fourth quarter of 2004 was $9.51 per boe compared with $8.74 per boe during the fourth quarter of 2003. The increase was due to a higher depletable capital base in the fourth quarter of 2004. This reflects the trend of increasing capital requirements for exploitation in the Western Canada Sedimentary Basin, particularly for shallow natural gas reservoirs and mature crude oil fields under secondary and tertiary recovery schemes.

Operating Statistics

Production, before Royalties

		Three months ended December 31		Year ended December 31	
		2004	2003	**2004**	2003
Light crude oil & NGL	*(mbbls/day)*	**60.9**	72.0	**66.2**	71.6
Medium crude oil	*(mbbls/day)*	**33.7**	37.9	**35.0**	39.2
Heavy crude oil	*(mbbls/day)*	**113.8**	107.8	**108.9**	99.9
Total crude oil & NGL	*(mbbls/day)*	**208.4**	217.7	**210.1**	210.7
Natural gas	*(mmcf/day)*	**697.4**	655.7	**689.2**	610.6
Barrels of oil equivalent (6:1)	*(mboe/day)*	**324.6**	327.0	**325.0**	312.5

Operating Netbacks

Western Canada

Light Crude Oil Netbacks [(1)]

	Three months ended December 31		Year ended December 31	
Per boe	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 51.15**	$ 35.48	**$ 46.12**	$ 39.91
Royalties	**7.89**	6.38	**7.76**	7.28
Operating costs	**10.10**	10.90	**8.94**	9.27
Netback	**$ 33.16**	$ 18.20	**$ 29.42**	$ 23.36

Medium Crude Oil Netbacks [(1)]

	Three months ended December 31		Year ended December 31	
Per boe	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 35.43**	$ 27.36	**$ 36.20**	$ 31.57
Royalties	**5.24**	4.54	**6.10**	5.28
Operating costs	**10.11**	9.47	**10.07**	9.53
Netback	**$ 20.08**	$ 13.35	**$ 20.03**	$ 16.76

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

Heavy Crude Oil Netbacks [1]

	Three months ended December 31		Year ended December 31	
Per boe	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 25.91**	$ 20.99	**$ 28.73**	$ 25.98
Royalties	**3.33**	2.02	**3.38**	2.76
Operating costs	**8.83**	8.52	**9.33**	9.09
Netback	**$ 13.75**	$ 10.45	**$ 16.02**	$ 14.13

Natural Gas Netbacks [2]

	Three months ended December 31		Year ended December 31	
Per mcfge	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 6.63**	$ 4.90	**$ 6.25**	$ 5.79
Royalties	**1.40**	0.98	**1.44**	1.29
Operating costs	**0.94**	0.78	**0.89**	0.79
Netback	**$ 4.29**	$ 3.14	**$ 3.92**	$ 3.71

Total Western Canada Upstream Netbacks [1]

	Three months ended December 31		Year ended December 31	
Per boe	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 35.10**	$ 26.56	**$ 35.01**	$ 31.58
Royalties	**5.99**	4.30	**6.22**	5.48
Operating costs	**7.91**	7.40	**7.85**	7.56
Netback	**$ 21.20**	$ 14.86	**$ 20.94**	$ 18.54

Terra Nova Crude Oil Netbacks

	Three months ended December 31		Year ended December 31	
Per boe	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 52.07**	$ 38.21	**$ 47.87**	$ 38.91
Royalties	**2.51**	0.95	**1.80**	0.81
Operating costs	**4.06**	2.67	**3.28**	3.16
Netback	**$ 45.50**	$ 34.59	**$ 42.79**	$ 34.94

Wenchang Crude Oil Netbacks

	Three months ended December 31		Year ended December 31	
Per boe	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 44.89**	$ 40.27	**$ 47.66**	$ 41.45
Royalties	**4.77**	5.13	**4.91**	3.80
Operating costs	**2.50**	2.71	**2.16**	1.94
Netback	**$ 37.62**	$ 32.43	**$ 40.59**	$ 35.71

Total Upstream Segment Netbacks [1]

	Three months ended December 31		Year ended December 31	
Per boe	**2004**	2003	**2004**	2003
Sales revenues before hedging	**$ 36.17**	$ 28.01	**$ 36.34**	$ 32.69
Royalties	**5.82**	4.17	**5.96**	5.11
Operating costs	**7.50**	6.87	**7.32**	6.92
Netback	**$ 22.85**	$ 16.97	**$ 23.06**	$ 20.66

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

MIDSTREAM

Upgrading Earnings Summary

(millions of dollars, except where indicated)		Three months ended December 31 2004	Three months ended December 31 2003	Year ended December 31 2004	Year ended December 31 2003
Gross margin		**$ 122**	$ 78	**$ 383**	$ 313
Operating costs		**54**	45	**214**	205
Other recoveries		**(1)**	-	**(5)**	(4)
Depreciation and amortization		**5**	5	**19**	20
Income taxes		**18**	10	**43**	21
Earnings		**$ 46**	$ 18	**$ 112**	$ 71
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**60.0**	69.8	**64.6**	72.5
Synthetic crude oil sales	*(mbbls/day)*	**52.5**	62.2	**53.7**	63.6
Upgrading differential	*($/bbl)*	**$ 25.72**	$ 13.40	**$ 17.79**	$ 12.88
Unit margin	*($/bbl)*	**$ 25.37**	$ 13.60	**$ 19.48**	$ 13.51
Unit operating cost [(2)]	*($/bbl)*	**$ 9.94**	$ 7.03	**$ 9.07**	$ 7.77

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

Fourth Quarter

Upgrading earnings increased in the fourth quarter of 2004 compared with the fourth quarter of 2003 primarily due to the following factors:

- a $12.32 per barrel increase in the upgrading differential

which was partially offset by:

- lower upgrader throughput during the fourth quarter of 2004
- higher unit operating costs, which were primarily related to energy costs
- higher income taxes

Twelve Months

Higher upgrader earnings in 2004 compared with 2003 resulted from primarily the same factors as those affecting the fourth quarter.

Infrastructure and Marketing Earnings Summary

(millions of dollars, except where indicated)		Three months ended December 31 2004	Three months ended December 31 2003	Year ended December 31 2004	Year ended December 31 2003
Gross margin	- pipeline	**$ 19**	$ 15	**$ 84**	$ 66
	- other infrastructure and marketing	**33**	36	**136**	141
		52	51	**220**	207
Other expenses		**1**	1	**8**	8
Depreciation and amortization		**5**	6	**21**	21
Income taxes		**15**	16	**63**	64
Earnings		**$ 31**	$ 28	**$ 128**	$ 114
Selected operating data:					
Aggregate pipeline throughput	*(mbbls/day)*	**479**	502	**492**	484

Fourth Quarter

Higher infrastructure and marketing earnings in the fourth quarter of 2004 compared with the fourth quarter of 2003 were primarily the result of the following factors:

- higher heavy crude oil pipeline tariffs and handling income which was partially offset by:

- lower Lloyd blend marketing margins

Twelve Months

Higher infrastructure and marketing earnings in 2004 compared with 2003 resulted from primarily the same factors as those affecting the fourth quarter of 2004 except that during 2004 Lloyd blend marketing margins contributed to the overall increase in earnings and natural gas marketing margins were lower.

REFINED PRODUCTS

Refined Products Earnings Summary (1)

(millions of dollars, except where indicated)		Three months ended December 31 2004	2003	Year ended December 31 2004	2003
Gross margin - fuel sales		**$ 7**	$ 16	**$ 93**	$ 71
- ancillary sales		**8**	7	**30**	28
- asphalt sales		**10**	16	**51**	51
		25	39	**174**	150
Operating and other expenses		**18**	23	**71**	74
Depreciation and amortization		**11**	6	**38**	26
Income taxes		**(1)**	4	**24**	18
Earnings (loss)		**$ (3)**	$ 6	**$ 41**	$ 32
Selected operating data:					
Number of fuel outlets				**531**	552
Light oil sales	*(million litres/day)*	**8.1**	8.2	**8.4**	8.2
Light oil sales per outlet	*(thousand litres/day)*	**12.0**	11.0	**11.7**	10.8
Prince George refinery throughput	*(mbbls/day)*	**8.6**	11.5	**9.8**	10.3
Asphalt sales	*(mbbls/day)*	**20.8**	19.7	**22.8**	22.0
Lloydminster refinery throughput	*(mbbls/day)*	**26.1**	26.1	**25.3**	25.7

(1) *2003 amounts as restated. Refer to note 3 to the consolidated financial statements.*

Fourth Quarter

Lower refined product earnings in the fourth quarter of 2004 compared with the fourth quarter of 2003 were primarily the result of the following factors:

- lower light oil product margins
- lower asphalt product margins
- higher depreciation

which were partially offset by:

- lower operating costs
- lower income taxes

Twelve Months

Higher refined product earnings in 2004 compared with 2003 were primarily the result of the following factors:

- higher light oil product margins
- higher restaurant and food store income

which were partially offset by:

- lower asphalt products margins

CORPORATE

(millions of dollars)	Three months ended December 31 2004	Three months ended December 31 2003	Year ended December 31 2004	Year ended December 31 2003
Intersegment eliminations - net	**$ (11)**	$ (11)	**$ 14**	$ (14)
Administration expenses	**11**	10	**27**	22
Stock-based compensation	**22**	-	**67**	-
Accretion	**-**	-	**2**	-
Other - net	**3**	1	**8**	3
Depreciation and amortization	**(2)**	13	**24**	36
Interest - net	**6**	16	**33**	73
Foreign exchange	**(46)**	(43)	**(99)**	(215)
Income taxes	**(15)**	(1)	**(88)**	45
Earnings	**$ 32**	$ 15	**$ 12**	$ 50

Foreign Exchange

(millions of dollars)	Three months ended December 31 2004	Three months ended December 31 2003	Year ended December 31 2004	Year ended December 31 2003
(Gain) loss on translation of U.S. dollar denominated long-term debt				
Realized	**$ (5)**	$ 12	**$ (10)**	$ 11
Unrealized	**(68)**	(72)	**(119)**	(326)
	(73)	(60)	**(129)**	(315)
Cross currency swaps				
Realized	**-**	32	**-**	32
Unrealized	**19**	(9)	**27**	41
	19	23	**27**	73
Other (gains) losses	**8**	(6)	**3**	27
	$ (46)	$ (43)	**$ (99)**	$ (215)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.791**	U.S. $0.741	**U.S. $0.774**	U.S. $0.633
At end of period	**U.S. $0.831**	U.S. $0.774	**U.S. $0.831**	U.S. $0.774

Fourth Quarter

Corporate earnings were higher in the fourth quarter of 2004 compared with the fourth quarter of 2003 primarily due to the following:

- income tax recoveries in 2004
- higher foreign exchange gains
- lower depreciation and amortization
- lower interest expense due to lower rates and higher capitalized interest

which were partially offset by:

- stock-based compensation for which there is no corresponding amount in 2003. The stock-based compensation in 2004 primarily resulted from amendments made to our stock option plan in June 2004

Twelve Months

Corporate earnings were lower in 2004 compared with 2003 primarily due to the following:

- lower foreign exchange gains
- stock-based compensation
- higher profit eliminations
- higher general corporate expenses

which were partially offset by:

- lower depreciation and amortization
- lower interest expense due to lower rates and higher capitalized interest
- higher income tax recoveries

CAPITAL EXPENDITURES

	Three months ended December 31		Year ended December 31	
(millions of dollars)	**2004**	2003	**2004**	2003
Upstream				
Exploration				
Western Canada	**$ 77**	$ 88	**$ 322**	$ 326
East Coast Canada	**7**	-	**24**	24
International	**2**	5	**18**	26
	86	93	**364**	376
Development				
Western Canada	**356**	284	**1,211**	869
East Coast Canada	**160**	194	**515**	533
International	**62**	-	**67**	-
	578	478	**1,793**	1,402
	664	571	**2,157**	1,778
Midstream				
Upgrader	**24**	10	**62**	25
Infrastructure and Marketing	**19**	7	**31**	18
	43	17	**93**	43
Refined Products	**53**	30	**106**	58
Corporate	**4**	9	**23**	23
Capital expenditures	**764**	627	**2,379**	1,902
Settlement of capital asset retirement obligations	**(12)**	(10)	**(30)**	(34)
Capital expenditures per Consolidated Statements of Cash Flows	**$ 752**	$ 617	**$ 2,349**	$ 1,868

Capital expenditures exclude capitalized costs related to asset retirement obligations incurred during the period and corporate acquisitions.

Wells Drilled (1) (2)

		Three months ended December 31				Year ended December 31			
		2004		2003		**2004**		2003	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Western Canada									
Exploration	Oil	**26**	**23**	3	3	**45**	**39**	12	11
	Gas	**81**	**46**	45	32	**234**	**180**	147	124
	Dry	**4**	**3**	1	1	**34**	**33**	22	21
		111	**72**	49	36	**313**	**252**	181	156
Development	Oil	**156**	**131**	120	116	**552**	**499**	520	490
	Gas	**175**	**148**	141	137	**807**	**740**	540	518
	Dry	**6**	**5**	5	5	**57**	**53**	60	57
		337	**284**	266	258	**1,416**	**1,292**	1,120	1,065
		448	**356**	315	294	**1,729**	**1,544**	1,301	1,221

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

OIL AND GAS RESERVES

Reserve Reconciliation

	Canada					International	Total		
	Western Canada				East Coast				
	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Light Crude Oil (mmbbls)	Light Crude Oil (mmbbls)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	(mmboe)
Proved reserves, before royalties									
Proved reserves at									
December 31, 2003	173	94	227	2,059	26	24	544	2,059	887
Revision of previous estimate	1	1	(114)	(23)	(1)	3	(110)	(23)	(114)
Purchase of reserves in place	1	-	-	23	-	-	1	23	5
Sales of reserves in place	-	-	(1)	(14)	-	-	(1)	(14)	(3)
Discoveries and extensions	8	4	33	376	27	-	72	376	135
Production	(12)	(13)	(40)	(252)	(5)	(7)	(77)	(252)	(119)
Proved reserves at									
December 31, 2004	171	86	105	2,169	47	20	429	2,169	791

Our oil and gas reserves are estimated in accordance with the regulations and guidance of the U.S. Securities and Exchange Commission ("SEC"), which, among other things, requires reserves to be evaluated using prices in effect on the day the reserves are estimated. We have significant oil reserves that are heavy with an API gravity of 12-14 degrees. Heavy crude oil sells at a discount to light crude oils such as West Texas Intermediate, which has an API gravity of approximately 40 degrees, because it requires upgrading before it can be processed by conventional refineries. There is a finite capacity for upgrading in North America, which is often reached when heavy crude oil from other countries enters the North American market. Heavy crude oil requires blending with condensate or light synthetic crude oil ("diluent") in order for it to be transported in a pipeline. During the winter, heavy crude oil requires a higher proportion of diluent because of the cold temperatures and diluent prices are similar to light crude oil prices. Heavy crude oil is also processed into asphalt, which is typically in demand during the spring to fall paving months.

As a result of these factors, prices for heavy crude oil are historically low in December. During 2004 the price of heavy crude oil at Lloydminster averaged $28.75 per barrel but on December 31, 2004, the date our oil and gas reserves were evaluated, the calculated price of Lloydminster heavy crude oil was $12.27 per barrel while the price for Husky Synthetic Blend was just under $50.00 per barrel. Husky Synthetic Blend is produced in our upgrading facility in Lloydminster, which was constructed to capture the difference in value between heavy crude oil and high quality synthetic crude oil. At $12.27 per barrel, 86 percent of our proved undeveloped heavy crude oil reserves in the Lloydminster area did not produce positive cash flow after the required capital investment and, in accordance with SEC regulation, were required to be subtracted as a negative revision from proved reserves until prices increase sufficiently to return those reserves to economic status. In addition, 39 percent of our proved developed reserves were uneconomic on December 31, 2004, and were included in the negative revision. The SEC requires oil and gas reserves to be economic at the well head and does not permit consideration of other economic factors such as our upgrading facility, which at December 31, 2004, produced cash netback of approximately $30.00 per barrel after royalties, lease operating costs, transportation and upgrading operating costs. When considering our upgrading, asphalt refining and other heavy oil infrastructure, our heavy oil production was economic to the Company at December 31, 2004. Notwithstanding the economics at December 31, 2004, on January 10, 2005, the price of Lloydminster heavy crude oil had returned to $21.56 per barrel, a price sufficient to return 98 percent of the reserves subtracted by negative revision to the proved reserve category.

The following table shows our reserves after considering our upgrading capacity.

	Canada					International			
	Western Canada				East Coast		Total		
	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Light Crude Oil (mmbbls)	Light Crude Oil (mmbbls)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	(mmboe)
Proved reserves at December 31, 2004	171	86	105	2,169	47	20	429	2,169	791
Heavy oil price revision at $12.27	-	-	120	3	-	-	120	3	120
Proved reserves excluding heavy oil revision at December 31, 2004	171	86	225	2,172	47	20	549	2,172	911

Notwithstanding negative revisions from low heavy oil prices at December 31, 2004, during 2004 we added 146 million barrels of oil equivalent from discoveries, extensions, improved recovery, acquisitions and technical revisions. Reserves were added at White Rose, Lloydminster and in the foothills and Deep Basin of Alberta and northeast British Columbia.

These additions to crude oil reserves amounted to 83 million barrels and were primarily from the Lloydminster reservoir extensions from step-out drilling and improved recovery. At White Rose offshore Newfoundland and Labrador 23 million barrels qualified as proved reserves.

These additions to natural gas reserves amounted to 379 billion cubic feet and were primarily related to our drilling program in the foothills and Deep Basin areas of Alberta and northeast British Columbia. Natural gas reserve additions also resulted from field extensions at Ekwan Sierra, Rainbow, Abbey in southwest Saskatchewan and areas throughout the Alberta foothills and Deep Basin. Negative technical revisions of previously estimated natural gas reserves were primarily related to reservoir performance.

Finding and Development Costs - includes heavy oil revision

Western Canada (*Excludes oil sands and acquisitions/divestitures)*				
Year ended December 31	**2002-2004**	**2004**	2003	2002
Total capitalized costs *($ millions)*	**$ 3,600**	**$ 1,476**	$ 1,130	$ 994
Proved reserve additions and revisions *(mmboe)*	**163**	**(9)**	77	95
Average cost per boe	**$ 22.15**	**n/a**	$ 14.75	$ 10.49

Finding and Development Costs - excludes heavy oil revision

Western Canada (*Excludes oil sands and acquisitions/divestitures)*				
Year ended December 31	**2002-2004**	**2004**	2003	2002
Total capitalized costs *($ millions)*	**$ 3,600**	**$ 1,476**	$ 1,130	$ 994
Proved reserve additions and revisions *(mmboe)*	**283**	**111**	77	95
Average cost per boe	**$ 12.73**	**$ 13.26**	$ 14.75	$ 10.49

Production Replacement - includes heavy oil revision

Western Canada (*Excludes oil sands)*				
Year ended December 31	**2002-2004**	**2004**	2003	2002
Production *(mmboe)*	**307**	**107**	100	100
Proved reserve additions and revisions *(mmboe)*	**163**	**(9)**	77	95
Production replacement ratio *(excluding net acquisitions) (percent)*	**53**	**(8)**	77	95
Proved reserve additions and revisions *(including net acquisitions) (mmboe)*	**185**	**(7)**	111	81
Production replacement ratio *(including net acquisitions) (percent)*	**60**	**(7)**	111	81

Production Replacement - excludes heavy oil revision

Western Canada (*Excludes oil sands*) *Year ended December 31*	2002-2004	2004	2003	2002
Production *(mmboe)*	**307**	**107**	100	100
Proved reserve additions and revisions *(mmboe)*	**283**	**111**	77	95
Production replacement ratio *(excluding net acquisitions) (percent)*	**92**	**104**	77	95
Proved reserve additions and revisions *(including net acquisitions) (mmboe)*	**305**	**113**	111	81
Production replacement ratio *(including net acquisitions) (percent)*	**100**	**106**	111	81

Recycle Ratio

The recycle ratio measures the efficiency of Husky's capital program by comparing the cost of finding and developing proved reserves with the netback from production. The ratio is calculated by dividing the operating netback by the proved finding and development cost on a barrels of oil equivalent basis.

Recycle Ratio - includes heavy oil revision

Western Canada *(Excludes oil sands)* *Year ended December 31*	2002-2004	2004	2003	2002
Operating netback *($/boe)*	**$ 18.56**	**$ 20.94**	$ 18.54	$ 16.04
Proved finding and development cost *($/boe)*	**$ 22.15**	**n/a**	$ 14.75	$ 10.49
Recycle ratio	**0.84**	**n/a**	1.26	1.53

Recycle Ratio - excludes heavy oil revision

Western Canada *(Excludes oil sands)* *Year ended December 31*	2002-2004	2004	2003	2002
Operating netback *($/boe)*	**$ 18.56**	**$ 20.94**	$ 18.54	$ 16.04
Proved finding and development cost *($/boe)*	**$ 12.73**	**$ 13.26**	$ 14.75	$ 10.49
Recycle ratio	**1.46**	**1.58**	1.26	1.53

Forward-looking Statements

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

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

The reader is cautioned not to place undue reliance on Husky's forward-looking statements. Husky's actual results may differ materially from those expressed or implied by Husky's forward-looking statements as a result of known and unknown risks, uncertainties and other factors. 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 Husky's control, that could influence actual results include, but are not limited to:

- **fluctuations in commodity prices**
- **changes in general economic, market and business conditions**

- fluctuations in supply and demand for Husky's products
- fluctuations in the cost of borrowing
- Husky's use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates
- political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which Husky operates
- Husky's ability to receive timely regulatory approvals
- the integrity and reliability of Husky's capital assets
- the cumulative impact of other resource development projects
- estimated production levels and Husky's success at exploration and development drilling and related activities
- the maintenance of satisfactory relationships with unions, employee associations and joint venturers
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- actions by governmental authorities, including changes in environmental and other regulations
- the ability and willingness of parties with whom Husky has material relationships to fulfil their obligations
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect Husky

Disclosure of Proved Oil and Gas Reserves and Other Oil and Gas Information

The Company's disclosure of proved oil and gas reserves and other information about its oil and gas activities has been made based on reliance of an exemption granted by the Canadian Securities Administrators. The exemption permits the Company to make these disclosures in accordance with requirements in the United States. These requirements and, consequently, the information presented may differ from Canadian requirements under National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." The proved oil and gas reserves disclosed in the news release have been evaluated using the U.S. standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934. The probable (and other classes) oil and gas reserves disclosed in this news release have been evaluated in accordance with the Society of Petroleum Engineers.

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.

Cautionary note to U.S. Investors – The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The Company uses certain terms in this news release, such as probable (possible, recoverable, established, etc.) that the SEC's guidelines strictly prohibit from inclusion in filings with the SEC.

Non-GAAP Measures

Disclosure of Cash Flow from Operations

The fourth quarter report 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 the Company's financial performance. The Company's 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.

CONSOLIDATED BALANCE SHEETS

(millions of dollars)	**December 31 2004**	December 31 2003
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 7**	$ 3
Accounts receivable	**446**	618
Inventories	**274**	198
Prepaid expenses	**52**	33
	779	852
Property, plant and equipment - (full cost accounting) *(notes 3, 4)*	**19,451**	16,957
Less accumulated depletion, depreciation and amortization	**7,258**	6,095
	12,193	10,862
Goodwill	**160**	120
Other assets	**106**	112
	$ 13,238	$ 11,946
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans	**$ 49**	$ 71
Accounts payable and accrued liabilities	**1,489**	1,126
Long-term debt due within one year *(note 5)*	**56**	259
	1,594	1,456
Long-term debt *(note 5)*	**1,776**	1,439
Other long-term liabilities *(notes 3, 4)*	**632**	519
Future income taxes *(notes 4, 6)*	**2,758**	2,621
Commitments and contingencies *(note 7)*		
Shareholders' equity		
Capital securities and accrued return	**278**	298
Common shares *(notes 3, 8)*	**3,506**	3,457
Retained earnings	**2,694**	2,156
	6,478	5,911
	$ 13,238	$ 11,946
Common shares outstanding *(millions) (note 8)*	**423.7**	422.2

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 amounts as restated.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of dollars, except per share amounts)	Three months ended December 31 2004	2003	Year ended December 31 2004	2003
	(unaudited)	*(unaudited)*	*(unaudited)*	*(audited)*
Sales and operating revenues, net of royalties	**$ 2,018**	$ 1,800	**$ 8,440**	$ 7,658
Costs and expenses				
Cost of sales and operating expenses *(notes 3, 4)*	**1,380**	1,172	**5,706**	4,847
Selling and administration expenses	**36**	33	**135**	119
Stock-based compensation *(notes 3, 8)*	**22**	-	**67**	-
Depletion, depreciation and amortization *(notes 3, 4)*	**302**	293	**1,179**	1,021
Interest - net *(note 5)*	**6**	16	**33**	73
Foreign exchange *(note 5)*	**(46)**	(43)	**(99)**	(215)
Other - net	**3**	1	**8**	3
	1,703	1,472	**7,029**	5,848
Earnings before income taxes	**315**	328	**1,411**	1,810
Income taxes *(note 6)*				
Current	**102**	22	**302**	147
Future	**(5)**	70	**103**	329
	97	92	**405**	476
Net earnings	**$ 218**	$ 236	**$ 1,006**	$ 1,334
Earnings per share *(note 9)*				
Basic	**$ 0.53**	$ 0.60	**$ 2.37**	$ 3.26
Diluted	**$ 0.52**	$ 0.59	**$ 2.36**	$ 3.25
Weighted average number of common shares outstanding *(millions) (note 9)*				
Basic	**423.7**	421.7	**423.4**	419.5
Diluted	**426.8**	423.8	**425.7**	421.5

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(millions of dollars)	Three months ended December 31 2004	2003	Year ended December 31 2004	2003
	(unaudited)	*(unaudited)*	*(unaudited)*	*(audited)*
Beginning of period *(note 4)*	**$ 2,749**	$ 1,946	**$ 2,156**	$ 1,357
Net earnings	**218**	236	**1,006**	1,334
Dividends on common shares - ordinary	**(51)**	(42)	**(195)**	(160)
- special	**(229)**	-	**(229)**	(420)
Return and foreign exchange on capital securities (net of related taxes)	**7**	16	**-**	36
Stock-based compensation - retroactive adoption *(note 3)*	**-**	-	**(44)**	-
Asset retirement obligations - retroactive adoption *(notes 3, 4)*	**-**	-	**-**	9
End of period	**$ 2,694**	$ 2,156	**$ 2,694**	$ 2,156

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 amounts as restated.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of dollars)	Three months ended December 31 **2004**	Three months ended December 31 2003	Year ended December 31 **2004**	Year ended December 31 2003
	(unaudited)	*(unaudited)*	*(unaudited)*	*(audited)*
Operating activities				
Net earnings	**$ 218**	$ 236	**$ 1,006**	$ 1,334
Items not affecting cash				
Accretion *(notes 3, 4)*	**6**	7	**27**	22
Depletion, depreciation and amortization *(notes 3, 4)*	**302**	293	**1,179**	1,021
Future income taxes	**(5)**	70	**103**	329
Foreign exchange	**(55)**	(37)	**(103)**	(242)
Other	**10**	(1)	**11**	(5)
Settlement of asset retirement obligations	**(16)**	(10)	**(40)**	(34)
Change in non-cash working capital *(note 10)*	**131**	(41)	**169**	113
Cash flow - operating activities	**591**	517	**2,352**	2,538
Financing activities				
Bank operating loans financing - net	**2**	71	**(22)**	71
Long-term debt issue	**534**	598	**2,200**	598
Long-term debt repayment	**(442)**	(815)	**(1,937)**	(971)
Settlement of cross currency swap	**-**	(32)	**-**	(32)
Return on capital securities payment	**-**	-	**(26)**	(29)
Debt issue costs	**-**	-	**(5)**	-
Proceeds from exercise of stock options	**1**	13	**18**	51
Proceeds from monetization of financial instruments	**8**	-	**8**	44
Dividends on common shares	**(280)**	(42)	**(424)**	(580)
Change in non-cash working capital *(note 10)*	**319**	(191)	**337**	48
Cash flow - financing activities	**142**	(398)	**149**	(800)
Available for investing	**733**	119	**2,501**	1,738
Investing activities				
Capital expenditures	**(752)**	(617)	**(2,349)**	(1,868)
Corporate acquisitions	**-**	(809)	**(102)**	(809)
Asset sales	**2**	459	**36**	511
Other	**(9)**	2	**(19)**	5
Change in non-cash working capital *(note 10)*	**31**	119	**(63)**	120
Cash flow - investing activities	**(728)**	(846)	**(2,497)**	(2,041)
Increase (decrease) in cash and cash equivalents	**5**	(727)	**4**	(303)
Cash and cash equivalents at beginning of period	**2**	730	**3**	306
Cash and cash equivalents at end of period	**$ 7**	$ 3	**$ 7**	$ 3

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2003 amounts as restated.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Year ended December 31, 2004 (unaudited)

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

Note 1 Segmented Financial Information

	Upstream		Midstream				Refined Products		Corporate and Eliminations [(2)]		Total	
			Upgrading		Infrastructure and Marketing							
	2004	2003	**2004**	2003	**2004**	2003	**2004**	2003	**2004**	2003	**2004**	2003
Three months ended December 31 [(1)]												
Sales and operating revenues, net of royalties	**$ 722**	$ 722	**$ 291**	$ 229	**$ 1,455**	$ 1,139	**$ 465**	$ 335	**$ (915)**	$ (625)	**$ 2,018**	$ 1,800
Costs and expenses												
Operating, cost of sales, selling and general	**247**	227	**222**	196	**1,404**	1,089	**458**	319	**(890)**	(625)	**1,441**	1,206
Depletion, depreciation and amortization	**283**	263	**5**	5	**5**	6	**11**	6	**(2)**	13	**302**	293
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**6**	16	**6**	16
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(46)**	(43)	**(46)**	(43)
	530	490	**227**	201	**1,409**	1,095	**469**	325	**(932)**	(639)	**1,703**	1,472
Earnings (loss) before income taxes	**192**	232	**64**	28	**46**	44	**(4)**	10	**17**	14	**315**	328
Current income taxes	**89**	5	**-**	1	**-**	22	**-**	(13)	**13**	7	**102**	22
Future income taxes	**(9)**	58	**18**	9	**15**	(6)	**(1)**	17	**(28)**	(8)	**(5)**	70
Net earnings (loss)	**$ 112**	$ 169	**$ 46**	$ 18	**$ 31**	$ 28	**$ (3)**	$ 6	**$ 32**	$ 15	**$ 218**	$ 236
Capital expenditures - Three months ended December 31	**$ 664**	$ 571	**$ 24**	$ 10	**$ 19**	$ 7	**$ 53**	$ 30	**$ 4**	$ 9	**$ 764**	$ 627
Year ended December 31 [(1)]												
Sales and operating revenues, net of royalties	**$ 3,120**	$ 3,186	**$ 1,058**	$ 1,013	**$ 6,126**	$ 4,946	**$ 1,797**	$ 1,502	**$ (3,661)**	$ (2,989)	**$ 8,440**	$ 7,658
Costs and expenses												
Operating, cost of sales, selling and general	**967**	873	**884**	901	**5,914**	4,747	**1,694**	1,426	**(3,543)**	(2,978)	**5,916**	4,969
Depletion, depreciation and amortization	**1,077**	918	**19**	20	**21**	21	**38**	26	**24**	36	**1,179**	1,021
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**33**	73	**33**	73
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(99)**	(215)	**(99)**	(215)
	2,044	1,791	**903**	921	**5,935**	4,768	**1,732**	1,452	**(3,585)**	(3,084)	**7,029**	5,848
Earnings (loss) before income taxes	**1,076**	1,395	**155**	92	**191**	178	**65**	50	**(76)**	95	**1,411**	1,810
Current income taxes	**211**	95	**-**	1	**31**	27	**11**	9	**49**	15	**302**	147
Future income taxes	**152**	233	**43**	20	**32**	37	**13**	9	**(137)**	30	**103**	329
Net earnings (loss)	**$ 713**	$ 1,067	**$ 112**	$ 71	**$ 128**	$ 114	**$ 41**	$ 32	**$ 12**	$ 50	**$ 1,006**	$ 1,334
Capital employed - As at December 31	**$ 7,747**	$ 6,709	**$ 480**	$ 456	**$ 255**	$ 348	**$ 354**	$ 315	**$ (477)**	$ (148)	**$ 8,359**	$ 7,680
Capital expenditures - Year ended December 31	**$ 2,157**	$ 1,778	**$ 62**	$ 25	**$ 31**	$ 18	**$ 106**	$ 58	**$ 23**	$ 23	**$ 2,379**	$ 1,902
Total assets - As at December 31	**$ 11,172**	$ 9,949	**$ 708**	$ 650	**$ 599**	$ 702	**$ 625**	$ 540	**$ 134**	$ 105	**$ 13,238**	$ 11,946

[(1)] *2003 amounts as restated.*

[(2)] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.*

Note 2 Significant Accounting Policies

The interim consolidated financial statements of Husky Energy Inc. (“Husky” or “the Company”) have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2003, 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, 2003. Certain prior years’ amounts have been reclassified to conform with current presentation.

Note 3 Change in Accounting Policies

a) Asset Retirement Obligations

Effective January 1, 2004, the Company retroactively adopted the Canadian Institute of Chartered Accountants (“CICA”) section 3110, “Asset Retirement Obligations”. The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion which is included in cost of sales and operating expenses. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Note 4 discloses the impact of the adoption of CICA section 3110 on the financial statements.

b) Stock-based Compensation

Effective January 1, 2004, the Company adopted the recommendations of CICA section 3870, “Stock-based Compensation and Other Stock-based Payments”, retroactively without restatement of prior periods. The recommendations require the Company to record a compensation expense over the vesting period based on the fair value of options granted to employees and directors. This change resulted in a decrease to retained earnings of $44 million, an increase to contributed surplus of $21 million and an increase to share capital of $23 million.

Effective June 1, 2004, the Company amended its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. The change resulted in an increase to current liabilities of $34 million, a decrease to contributed surplus of $16 million and an increase to stock-based compensation expense of $18 million. A liability for expected cash settlements is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company’s common shares. The liability is revalued to reflect changes in the market price of the Company’s common shares and the net change is recognized in earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital.

c) Property, Plant and Equipment - Oil and Gas

Effective January 1, 2004, the Company adopted Accounting Guideline 16, “Oil and Gas Accounting – Full Cost” (“AcG-16”), which replaces Accounting Guideline 5, “Full Cost Accounting in the Oil and Gas Industry”. AcG-16 modifies how the ceiling test is performed and is consistent with CICA section 3063, “Impairment of Long-lived Assets”. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre’s use and eventual disposition. If the carrying value is unrecoverable, the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company’s financial results.

d) Impairment of Long-lived Assets

Effective January 1, 2004, the Company adopted CICA section 3063, "Impairment of Long-lived Assets", which had no effect on the consolidated financial statements.

e) Hedging Relationships

Effective January 1, 2004, the Company adopted Accounting Guideline 13, "Hedging Relationships" ("AcG-13"), which establishes standards for the documentation and effectiveness testing of hedging activities. The adoption of AcG-13 had no effect on the Company's financial results.

f) Reclassification

Effective January 1, 2004, the Company adopted revised CICA section 1100, "Generally Accepted Accounting Principles". Upon adoption, certain transportation costs that were previously netted against revenue are now being recorded as cost of sales. This change has been adopted prospectively.

In the fourth quarter, the Company reclassified previously reported 2004 sales and operating revenues and operating expenses for hedging losses that had been included as a consolidated operating expense. This change had no impact on net earnings for each quarter.

Note 4 Asset Retirement Obligations

The Company retroactively adopted the new recommendations on the recognition of the obligations to retire long-lived tangible assets. The change was effective January 1, 2004 and the revision was applied retroactively. The impact was as follows:

Consolidated Balance Sheet - As at December 31, 2003

	As Reported [1]	Change	As Restated
Assets			
Net property, plant and equipment	$ 10,698	$ 164	$ 10,862
Liabilities and shareholders' equity			
Other long-term liabilities	390	129	519
Future income taxes	2,608	13	2,621
Retained earnings	2,134	22	2,156

[1] *Certain amounts have been reclassified to conform with current presentation.*

Consolidated Statement of Earnings - Year ended December 31, 2003

	As Reported	Change	As Restated
Depletion, depreciation and amortization	$ 1,058	$ (37)	$ 1,021
Accretion [1]	-	22	22
Future income taxes	327	2	329
Net earnings	1,321	13	1,334

[1] *Included in cost of sales and operating expenses.*

At December 31, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations was $2.9 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend up to 30 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 to 6.4 percent.

Changes to asset retirement obligations were as follows:

	Year ended December 31, 2004
Asset retirement obligations at beginning of year	$ 432
Liabilities incurred	90
Liabilities settled	(40)
Accretion	27
Asset retirement obligations at December 31	**$ 509**

Note 5 Long-term Debt

		December 31			
		2004	2003	**2004**	2003
	Maturity	*Cdn. $ Amount*		*U.S. $ Amount*	
Long-term debt					
Syndicated credit facility	2007	**$ 70**	$ -	**$ -**	$ -
Bilateral credit facilities	2006-7	**40**	-	**-**	-
7.125% notes	2006	**181**	194	**150**	150
6.25% notes	2012	**481**	517	**400**	400
7.55% debentures	2016	**241**	258	**200**	200
6.15% notes	2019	**361**	-	**300**	-
Private placement notes	2005	**18**	41	**15**	32
8.45% senior secured bonds	2005-12	**140**	188	**117**	145
Medium-term notes	2007-9	**300**	500	**-**	-
Total long-term debt		**1,832**	1,698	**$ 1,182**	$ 927
Amount due within one year		**(56)**	(259)		
		$ 1,776	$ 1,439		

During 2004, Husky increased its revolving syndicated credit facility from $830 million to $950 million and added another revolving bilateral credit facility of $50 million. At December 31, 2004, the Company had borrowed $70 million under its $950 million revolving syndicated credit facility and $40 million under its $150 million revolving bilateral credit facilities. Interest rates under the revolving 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 $150 million revolving bilateral credit facilities have substantially the same terms as the revolving syndicated credit facility.

On June 18, 2004, the Company issued U.S. $300 million of 6.15 percent notes due June 15, 2019, the second offering by Husky under a base shelf prospectus dated June 6, 2002 filed with securities regulatory authorities in Canada and the United States. This shelf prospectus expired on July 7, 2004. The notes issued are redeemable at the option of the Company at any time, subject to a make whole provision. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of Husky’s other unsecured and unsubordinated indebtedness. Net proceeds from the issue were used to repay bank indebtedness.

On August 12, 2004, the Company filed a base shelf prospectus with securities regulatory authorities in Canada and the United States. The prospectus permits Husky to offer for sale, from time to time, up to U.S. $1 billion of debt securities during the 25 months from August 12, 2004.

Interest - net consisted of:

	Three months ended December 31		Year ended December 31	
	2004	2003	**2004**	2003
Long-term debt	**$ 26**	$ 30	**$ 106**	$ 129
Short-term debt	**1**	1	**3**	2
	27	31	**109**	131
Amount capitalized	**(21)**	(15)	**(75)**	(52)
	6	16	**34**	79
Interest income	**-**	-	**(1)**	(6)
	$ 6	$ 16	**$ 33**	$ 73

Foreign exchange consisted of:

	Three months ended December 31		Year ended December 31	
	2004	2003	**2004**	2003
Gain on translation of U.S. dollar denominated long-term debt	**$ (73)**	$ (60)	**$ (129)**	$ (315)
Cross currency swaps	**19**	23	**27**	73
Other (gains) losses	**8**	(6)	**3**	27
	$ (46)	$ (43)	**$ (99)**	$ (215)

Note 6 Income Taxes

On May 11, 2004, Bill 27 – Alberta Corporate Tax Amendment Act, 2004 received royal assent in the Alberta Legislative Assembly. As a result, a non-recurring benefit of $40 million was recorded in 2004. Also during 2004, a net tax benefit of $16 million related to the change in the Company's stock option plan and other tax benefits net of adjustments was recognized. Income tax expense for the year ended December 31, 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, Bill C-48 amended the Income Tax Act (natural resources) and resulted in a non-recurring tax benefit of $141 million. The resource tax changes included a change in the federal tax rate, deductibility of crown royalties and elimination of the resource allowance, to be phased in over a five-year period.

Note 7 Commitments and Contingencies

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

Note 8 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:

	Year ended December 31			
	2004		2003	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of period	422,175,742	$ 3,457	417,873,601	$ 3,406
Stock-based compensation - adoption	-	23	-	-
Exercised - options and warrants	1,560,672	26	4,302,141	51
Balance at December 31	**423,736,414**	**$ 3,506**	422,175,742	$ 3,457

Stock Options

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

	Year ended December 31			
	2004		2003	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	4,597	$ 13.88	7,920	$ 13.91
Granted	8,200	$ 25.10	591	$ 19.17
Exercised for common shares	(1,350)	$ 13.11	(3,789)	$ 13.45
Surrendered for cash	(1,269)	$ 13.32	-	$ -
Forfeited	(214)	$ 22.73	(125)	$ 14.71
Outstanding, December 31	**9,964**	**$ 22.61**	4,597	$ 13.88
Options exercisable at December 31	1,417	$ 13.04	3,564	$ 12.93

	December 31, 2004				
	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
$9.86 - $14.99	1,443	$ 12.75	1.0	1,320	$ 12.57
$15.00 - $23.99	475	$ 18.40	3.5	97	$ 19.39
$24.00 - $32.14	8,046	$ 24.62	4.4	-	$ -
	9,964	$ 22.61	3.9	1,417	$ 13.04

A downward adjustment of $0.48 was made to the exercise price of all outstanding stock options effective November 29, 2004, pursuant to the terms of the stock option plan under which the options were issued as a result of the special $0.54 per share dividend that was declared in November 2004.

Stock-based Compensation

Beginning January 1, 2004, stock-based compensation is being recognized in earnings. As described in note 3 b), on June 1, 2004, the Company modified its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment.

Prior to modification, the fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The grant date fair values and assumptions used prior to June 1, 2004 were:

	Three months ended December 31		Year ended December 31	
	2004	2003 [1]	**2004**	2003 [1]
Weighted average fair value per option	**$ -**	$ 4.29	**$ 5.67**	$ 4.00
Risk-free interest rate *(percent)*	**-**	3.7	**3.1**	3.9
Volatility *(percent)*	**-**	19	**21**	23
Expected life *(years)*	**-**	5	**5**	5
Expected annual dividend per share	**$ -**	$ 0.40	**$ 0.44**	$ 0.36

[1] *Options granted prior to September 3, 2003 were revalued as a result of the special $1.00 per share dividend paid in 2003.*

If the Company had applied the fair value based method retroactively with restatement of prior periods for all options granted, the Company's net earnings available to common shareholders would have decreased by $14 million in 2003 for stock-based compensation. Basic earnings per share would have decreased from $3.26 to $3.23 and diluted earnings per share would have decreased from $3.25 to $3.21.

Contributed Surplus

Changes to contributed surplus were as follows:

	Three months ended December 31		Year ended December 31	
	2004	2003	**2004**	2003
Balance at beginning of period	**$ -**	$ -	**$ -**	$ -
Stock-based compensation - adoption	**-**	-	**21**	-
Stock-based compensation cost	**-**	-	**1**	-
Stock options exercised	**-**	-	**(6)**	-
Modification of stock option plan - June 1, 2004	**-**	-	**(16)**	-
Balance at December 31	**$ -**	$ -	**$ -**	$ -

Note 9 Earnings per Common Share

	Three months ended December 31		Year ended December 31	
	2004	2003	**2004**	2003
Net earnings	**$ 218**	$ 236	**$ 1,006**	$ 1,334
Return and foreign exchange on capital securities (net of related taxes)	**7**	16	**-**	36
Net earnings available to common shareholders	**$ 225**	$ 252	**$ 1,006**	$ 1,370
Weighted average number of common shares outstanding - Basic *(millions)*	**423.7**	421.7	**423.4**	419.5
Effect of dilutive stock options and warrants	**3.1**	2.1	**2.3**	2.0
Weighted average number of common shares outstanding - Diluted *(millions)*	**426.8**	423.8	**425.7**	421.5
Earnings per share				
- Basic	**$ 0.53**	$ 0.60	**$ 2.37**	$ 3.26
- Diluted	**$ 0.52**	$ 0.59	**$ 2.36**	$ 3.25

Note 10 Cash Flows - Change in Non-cash Working Capital

	Three months ended December 31		Year ended December 31	
	2004	2003	**2004**	2003
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 176**	$ 188	**$ 209**	$ (7)
Inventories	**12**	36	**(77)**	28
Prepaid expenses	**-**	35	**(12)**	(10)
Accounts payable and accrued liabilities	**293**	(372)	**323**	270
Change in non-cash working capital	**481**	(113)	**443**	281
Relating to:				
Financing activities	**319**	(191)	**337**	48
Investing activities	**31**	119	**(63)**	120
Operating activities	**$ 131**	$ (41)	**$ 169**	$ 113
b) Other cash flow information:				
Cash taxes paid	**$ 26**	$ 2	**$ 213**	$ 69
Cash interest paid	**$ 39**	$ 49	**$ 116**	$ 134

Note 11 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended December 31		Year ended December 31	
	2004	2003	**2004**	2003
Employer current service cost	**$ 4**	$ 3	**$ 16**	$ 15
Interest cost	**2**	1	**8**	8
Expected return on plan assets	**(1)**	(1)	**(7)**	(6)
Amortization of net actuarial losses	**1**	-	**2**	2
	$ 6	$ 3	**$ 19**	$ 19

Note 12 Financial Instruments and Risk Management

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

	December 31	
	2004	2003
Commodity price risk management		
Natural gas	**$ (9)**	$ (8)
Crude oil	**-**	(109)
Power consumption	**(1)**	2
Interest rate risk management		
Interest rate swaps	**52**	31
Foreign currency risk management		
Foreign exchange contracts	**(30)**	(19)
Foreign exchange forwards	**-**	15

Commodity Price Risk Management

Natural Gas Production

During 2004, the impact of the 2004 natural gas hedge program was a gain of $8 million.

At December 31, 2004, the Company had hedged 7.5 mmcf of natural gas per day at NYMEX from January to December 2005 at an average price of U.S. $1.92 per mcf. During 2004, the impact was a loss of $9 million.

Crude Oil Production

The impact of the hedge program during 2004 was a before tax loss of $560 million.

Power Consumption

At December 31, 2004, the Company had hedged power consumption of 197,100 MWh from January to December 2005 at an average fixed price of $49.94 per MWh and 65,160 MWh from January to June 2005 at an average fixed price of $48.00 per MWh. The impact of the hedge program during 2004 was a gain of $3 million.

Natural Gas Contracts

At December 31, 2004, the unrecognized gains (losses) on external offsetting physical purchase and sale natural gas contracts were as follows:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	14,276	$ (2)
Physical sale contracts	(14,276)	$ 3

Interest Rate Risk Management

The Company has interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms as at December 31, 2004:

Debt	Swap Amount	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
6.15% notes	U.S. $300	June 15, 2019	U.S. LIBOR + 63 bps

During 2004, the Company realized a gain of $22 million from interest rate risk management activities.

Foreign Currency Risk Management

At December 31, 2004, the Company had the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate
7.125% notes	U.S. $150	$ 218	November 15, 2006	8.74%
6.25% notes	U.S. $150	$ 212	June 15, 2012	7.41%

During 2004, the Company recognized a $13 million loss from all foreign currency risk management activities.

On November 10, 2004, the Company unwound its long-dated forwards totalling U.S. $36 million, which resulted in a gain of $8 million that has been deferred and will be recognized into income on the dates that the underlying hedged transactions are to take place.

Sale of Accounts Receivable

In December 2004, the Company increased the ceiling on its securitization program to sell, on a revolving basis, accounts receivable to a third party from $250 million to $350 million. As at December 31, 2004, $350 million in outstanding accounts receivable had been sold under the program. The agreement includes a program fee.

Note 13 Acquisition of Temple Exploration Inc.

Effective July 15, 2004, the Company acquired all of the issued and outstanding shares of Temple Exploration Inc. (“Temple”) for total cash consideration of $102 million. The results of Temple are included in the consolidated financial statements of the Company from the date of acquisition.

The allocation of the aggregate purchase price based on the estimated fair values of Temple's net assets acquired at July 15, 2004 was as follows:

Net assets acquired	
Working capital	$ (17)
Property, plant and equipment	138
Goodwill [1]	20
Future income taxes	(39)
	$ 102

(1) Allocated to the Company's upstream segment and not deductible for income tax purposes. Refer to note 1, Segmented Financial Information.

Terms and Abbreviations

bbls	barrels
bps	basis points
mbbls	thousand barrels
mbbls/day	thousand barrels per day
mmbbls	million barrels
mcf	thousand cubic feet
mmcf	million cubic feet
mmcf/day	million cubic feet per day
bcf	billion cubic feet
tcf	trillion cubic feet
boe	barrels of oil equivalent
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per day
mmboe	million barrels of oil equivalent
mcfge	thousand cubic feet of gas equivalent
GJ	gigajoule
mmbtu	million British Thermal Units
mmlt	million long tons
MW	megawatt
MWh	megawatt hour
NGL	natural gas liquids
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
NIT	NOVA Inventory Transfer (1)
LIBOR	London Interbank Offered Rate
CDOR	Certificate of Deposit Offered Rate
SEDAR	System for Electronic Document Analysis and Retrieval
FPSO	Floating production, storage and offloading vessel
OPEC	Organization of Petroleum Exporting Countries
Capital Employed	Short- and long-term debt and shareholders' equity
Capital Expenditures	Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets
Equity	Capital securities and accrued return, shares and retained earnings
Total Debt	Long-term debt including current portion and bank operating loans
hectare	1 hectare is equal to 2.47 acres
wildcat well	Exploratory well drilled in an area where no production exists
feedstock	Raw materials which are processed into petroleum products

(1) *NOVA Inventory Transfer is an exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline.*

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

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

Husky Energy will host a conference call for analysts and investors on Tuesday, January 18, 2005 at 4:15 p.m. Eastern time to discuss Husky's fourth quarter results.

To participate, please dial 1 (800) 404-8949 beginning at 4:05 p.m. Eastern time. Media are invited to participate in the call on a listen-only basis by dialing 1 (800) 428-5596 beginning at 4:05 p.m. Eastern time.

Those who are unable to listen to the call live may listen to a recording of the call by dialing 1 (800) 558-5253 one hour after the completion of the call, approximately 6:15 p.m. Eastern time, then dialing reservation number 21215863. The PostView will be available until Thursday, February 17, 2005.

- 30 -

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