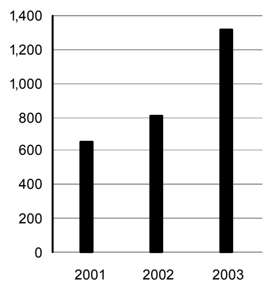
For Immediate Release
February 3, 2004

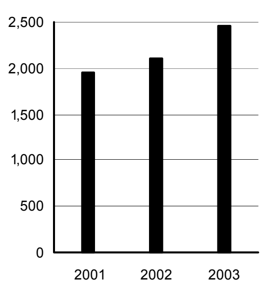
Q4

HUSKY ENERGY REPORTS 2003 EARNINGS OF $1.32 BILLION

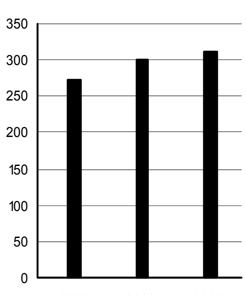
Net Earnings
($ millions)



Cash Flow from Operations
($ millions)



Total Production
(mboe/day)



(Calgary, Alberta) Husky Energy Inc. is pleased to report that it had another record performance in 2003. The Company today reported net earnings of $1.32 billion or $3.22 per share (diluted) in 2003, an increase of 64 percent compared with $804 million or $1.88 per share (diluted) in 2002. Cash flow from operations in 2003 increased 17 percent to $2.5 billion or $5.76 per share (diluted), up from $2.1 billion or $4.92 per share (diluted) in 2002.

Return on equity increased to 24.0 percent and return on average capital employed to 18.0 percent in 2003, compared with 16.7 percent and 12.2 percent, respectively in 2002.

"Husky's performance is due to our emphasis on operational and financial discipline. Our record earnings demonstrate our commitment to deliver superior returns to our shareholders," said Mr. John C. S. Lau, President & Chief Executive Officer.

The main contributors to the Company's financial performance were strong U.S. dollar commodity prices partially offset by the fall in value of the U.S. dollar, foreign exchange gains on U.S. denominated debt translation and lower tax provisions due to federal and provincial tax rate reductions. Net earnings for the year included a net gain of $190 million or $0.45 per share (diluted) on U.S. denominated debt translation and a positive adjustment of $161 million or $0.38 per share (diluted) related to tax rate changes.

Production for the year averaged 312,500 barrels of oil equivalent ("boe") per day compared with 300,200 boe during 2002. Total crude oil and natural gas liquids production for 2003 was 210,700 barrels per day, up three percent from 205,300 barrels per day during 2002. Natural gas production was 610.6 million cubic feet per day, up seven percent from 569.2 million cubic feet per day for 2002.

At December 31, 2003, Husky's net debt stood at $1.8 billion, down 15 percent from $2.1 billion at December 31, 2002. Capital expenditures for 2003 were $1.9 billion, up 12 percent from $1.7 billion for 2002.

"We are pleased with our financial performance in 2003," added Mr. Lau. "Domestically, the integration of Marathon Canada Limited into our operations was very successful. The development of our White Rose oil field is on schedule, and delineation drilling has identified an extension to the pool. Internationally, our opportunities continue to expand with our acquisition of additional exploration acreage in the East China Sea."

For the fourth quarter of 2003, Husky's net earnings were $245 million or $0.62 per share (diluted) compared with $242 million or $0.57 per share (diluted) in the fourth quarter of 2002.

Production for the fourth quarter of 2003 averaged 327,000 boe per day, compared with 317,900 boe per day in the fourth quarter of 2002. Total crude oil and natural gas liquids production for the fourth quarter was 217,700 barrels per day compared with 221,700 barrels per day for the same period in 2002. Natural gas production for the fourth quarter of 2003 averaged 655.7 million cubic feet per day compared with 577.4 million cubic feet per day for the same quarter in 2002. The increase of 14 percent in natural gas production reflects the benefit of the Marathon Canada acquisition.

In December 2003, Husky announced its 2004 capital expenditure program of $2.1 billion, with $1.8 billion for the upstream segment. Upstream activities will focus on natural gas exploration in Western Canada, oil exploration in the Northwest Territories, development of heavy oil and oil sands properties in Alberta, commissioning of the White Rose floating production, storage and offloading vessel ("FPSO"), and drilling of development wells for the Terra Nova and White Rose projects off Canada's East Coast. In addition, one offshore exploration well is planned to be drilled in the South Whale Basin, approximately 350 kilometres south of St. John's, Newfoundland and Labrador.

International activities include the planned drilling of at least two exploratory wells and additional seismic programs in the South China Sea and East China Sea.

Highlights

(millions of dollars, except per share amounts, ratios and production)		Three months ended December 31 (unaudited) 2003	2002	% Change	Year ended December 31 2003	2002	% Change
Sales and operating revenues, net of royalties		**$ 1,800**	$ 1,697	⇧ 6	**$ 7,658**	$ 6,384	⇧ 20
Cash flow from operations		**568**	635	⇩ 11	**2,459**	2,096	⇧ 17
Per share - Basic		**1.33**	1.50	⇩ 11	**5.79**	4.94	⇧ 17
- Diluted		**1.32**	1.50	⇩ 12	**5.76**	4.92	⇧ 17
Segmented earnings							
Upstream		**$ 174**	$ 210	⇩ 17	**$ 1,048**	$ 688	⇧ 52
Midstream		**46**	48	⇩ 4	**185**	161	⇧ 15
Refined Products		**5**	(1)	⇧ 600	**28**	32	⇩ 13
Corporate and eliminations		**20**	(15)	⇧ 233	**60**	(77)	⇧ 178
Net earnings		**$ 245**	$ 242	⇧ 1	**$ 1,321**	$ 804	⇧ 64
Per share - Basic		**$ 0.62**	$ 0.57	⇧ 9	**$ 3.23**	$ 1.88	⇧ 72
- Diluted		**0.62**	0.57	⇧ 9	**3.22**	1.88	⇧ 71
Dividend declared							
Per share - Ordinary		**0.10**	0.09	⇧ 11	**0.38**	0.36	⇧ 6
- Special		**-**	-	-	**1.00**	-	-
Return on average capital employed	*(percent)*				**18.0**	12.2	
Return on equity	*(percent)*				**24.0**	16.7	
Debt to capital employed	*(percent)*				**23.1**	31.8	
Debt to cash flow from operations	*(times)*				**0.7**	1.1	
Daily production, before royalties							
Light crude oil & NGL	*(mbbls/day)*	**72.0**	78.8	⇩ 9	**71.6**	65.4	⇧ 9
Medium crude oil	*(mbbls/day)*	**37.9**	43.5	⇩ 13	**39.2**	44.8	⇩ 13
Heavy crude oil	*(mbbls/day)*	**107.8**	99.4	⇧ 8	**99.9**	95.1	⇧ 5
Total crude oil & NGL	*(mbbls/day)*	**217.7**	221.7	⇩ 2	**210.7**	205.3	⇧ 3
Natural gas	*(mmcf/day)*	**655.7**	577.4	⇧ 14	**610.6**	569.2	⇧ 7
Barrels of oil equivalent (6:1)	*(mboe/day)*	**327.0**	317.9	⇧ 3	**312.5**	300.2	⇧ 4

Capital Expenditures

(millions of dollars)	Three months ended December 31 **2003**[(1)]	2002	Year ended December 31 **2003**[(1)]	2002
Upstream				
Exploration				
Western Canada	**$ 88**	$ 98	**$ 326**	$ 304
East Coast Canada	**-**	-	**24**	41
International	**5**	7	**26**	9
	93	105	**376**	354
Development				
Western Canada	**283**	228	**872**	730
East Coast Canada	**194**	97	**533**	417
International	**-**	1	**-**	66
	477	326	**1,405**	1,213
	570	431	**1,781**	1,567
Midstream				
Upgrader	**10**	11	**25**	41
Infrastructure and marketing	**8**	5	**18**	17
	18	16	**43**	58
Refined Products	**30**	22	**58**	44
Corporate	**9**	10	**23**	23
	$ 627	$ 479	**$ 1,905**	$ 1,692

(1) *2003 does not include the acquisition of Marathon Canada.*

Highlights

UPSTREAM

Acquisition of Marathon Canada

Husky acquired Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. ("Marathon Canada") effective October 1, 2003. The net acquisition cost of Marathon Canada, after receipt of proceeds from the sale of certain properties to a third party, was $400 million. The addition of the Marathon Canada properties added 39.8 million barrels of oil equivalent to proved reserves.

Production

Husky's total production in the fourth quarter of 2003 averaged 327,000 barrels of oil equivalent per day, an increase of nine percent compared with the third quarter of 2003. Crude oil and natural gas liquids production averaged 217,700 gross barrels per day in the fourth quarter of 2003 compared with 202,600 gross barrels per day in the third quarter of 2003.

- Compared with the third quarter of 2003, the increase in crude oil production in the fourth quarter was due primarily to the addition of properties retained from the acquisition of Marathon Canada and new wells brought on-stream, partially offset by reservoir declines and divestitures.
- In Western Canada 119 net oil wells were completed during the fourth quarter.
- Heavy crude oil production from the Lloydminster area averaged 107,800 barrels per day in the fourth quarter of 2003 compared with 99,200 barrels per day in the third quarter of 2003. Higher heavy crude oil production in the fourth quarter was due mainly to new primary production brought on-stream and additional production from the Celtic/Bolney thermal project.
- Light crude oil production from Terra Nova averaged 17,800 barrels per day in the fourth quarter of 2003 compared with 14,600 barrels per day during the third quarter of 2003. Production in the fourth quarter reflects a return to normal levels after production was reduced by a scheduled turnaround in the previous quarter.
- Production at Wenchang averaged 19,500 barrels per day in the fourth quarter of 2003, down four percent from the previous quarter, in line with anticipated reservoir declines.

Natural gas production averaged 655.7 million cubic feet per day in the fourth quarter of 2003, an increase of 12 percent compared with the third quarter of 2003. The increase in natural gas production was mainly attributable to the acquisition of Marathon Canada and exploratory and development wells recently tied-in, partially offset by reservoir declines.

Daily Production, Before Royalties

		Three months ended December 31		Year ended December 31	
		2003	2002	**2003**	2002
Light crude oil & NGL	*(mbbls/day)*	**72.0**	78.8	**71.6**	65.4
Medium crude oil	*(mbbls/day)*	**37.9**	43.5	**39.2**	44.8
Heavy crude oil	*(mbbls/day)*	**107.8**	99.4	**99.9**	95.1
Total crude oil & NGL	*(mbbls/day)*	**217.7**	221.7	**210.7**	205.3
Natural gas	*(mmcf/day)*	**655.7**	577.4	**610.6**	569.2
Barrels of oil equivalent (6:1)	*(mboe/day)*	**327.0**	317.9	**312.5**	300.2

Shackleton Natural Gas

Husky continued to expand the natural gas development of its 100 percent working interest in the Shackleton/Lacadena area during the fourth quarter of 2003. During the quarter Husky added compression facilities with over 8 million cubic feet per day of capacity and brought 40 wells on-stream to bring the total number of producing wells to 214. Sales gas during the month of December 2003 averaged 45 million cubic feet per day.

Thermal Production

During the fourth quarter of 2003 Husky further expanded thermal operations at Bolney/Celtic with eight new vertical wells. In addition, well and facilities optimizations at both Bolney/Celtic and Pikes Peak were completed. Husky's total thermal production increased during the fourth quarter to 17,700 barrels per day from 15,600 barrels per day in the third quarter of 2003.

Oil Sands - Alberta

Tucker

During the fourth quarter Husky completed supplementary information requirements of the Alberta Energy and Utilities Board and Alberta Environment on the Tucker project application. Husky is anticipating receiving confirmation shortly from the Alberta Energy and Utilities Board as to whether a hearing will be called on this application. If a hearing is not required, Husky would expect to receive regulatory approval in the first half of 2004. The Tucker project is a 30,000 barrel per day in-situ bitumen operation utilizing steam assisted gravity drainage technology.

Kearl

Preparation for a third stratigraphic test well program in 2004 is currently under way. The results of this program will serve to augment the current geological model and provide data to determine the appropriate capacity and configuration of this in-situ thermal project. Husky expects to file a Commercial Project Application with an Environmental Impact Assessment by June 30, 2004.

Exploration

Western Canada

During the fourth quarter of 2003 Husky drilled 36 net exploration wells, which resulted in three net oil well completions and 32 net natural gas well completions.

Exploration in Western Canada continues to be in the foothills and overthrust belt along the eastern slopes of the Rocky Mountains and in the deep basin in Alberta and northeastern British Columbia. In the fourth quarter Husky completed six discoveries in the foothills and deep basin at the Copton, Cordel and Minehead areas in Alberta. These wells will be tied-in in the first quarter of 2004.

Thirty exploration wells are planned to be drilled in northern Alberta and northeastern British Columbia in the first quarter of 2004. Preparation of leases and access roads in these areas is currently under way.

Wells Drilled (*Excludes stratigraphic test wells)*									
		Three months ended December 31				Year ended December 31			
		2003		2002		**2003**		2002	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Western Canada									
Exploration	Oil	**3**	**3**	3	3	**12**	**11**	21	20
	Gas	**45**	**32**	15	14	**147**	**124**	139	131
	Dry	**1**	**1**	3	2	**22**	**21**	15	14
		49	**36**	21	19	**181**	**156**	175	165
Development	Oil	**120**	**116**	128	107	**520**	**490**	497	453
	Gas	**141**	**137**	166	160	**540**	**518**	485	453
	Dry	**5**	**5**	17	17	**60**	**57**	58	55
		266	**258**	311	284	**1,120**	**1,065**	1,040	961
		315	**294**	332	303	**1,301**	**1,221**	1,215	1,126

Offshore China

During the fourth quarter of 2003, processing of seismic data shot in the Beibu Wan Basin in the South China Sea was undertaken. The program involved a 1,000 square kilometre 3-D program that was completed on Block 23/15 during the third quarter of 2003. Husky expects to drill a test well in this area in the first half of 2004.

On the deep water Block 40/30 in the Pearl River Basin, a large prospective structure has been identified and a drilling rig has been contracted. Drilling in 600 metres of water is expected to commence at Changchang 12-1-1 in the second quarter of 2004.

On November 3, 2003 Husky signed a petroleum contract with the China National Offshore Oil Corporation for the 04/35 exploration block in the East China Sea. The block is located 350 kilometres east of Shanghai and covers 4,835 square kilometres with average water depths of 100 metres. The contract requires Husky to drill one well during the first three years of its term.

Major Project Update

East Coast, Canada Offshore

White Rose

In October 2003 a batch development drilling program commenced in the south glory hole with the spudding of eight wells. All eight wells were set with 76 centimetre conductor casing and surface casing was set to a depth of 1,200 metres in six wells. The technique of batch drilling, as opposed to sequential drilling, is expected to increase overall efficiency and reduce costs. The integration of the turret with the hull of the FPSO was completed during the fourth quarter of 2003. The vessel underwent sea trials in December and was officially named the “Sea Rose” at a ceremony in January 2004. The Sea Rose FPSO is undergoing final preparations for its 14,000 nautical mile journey from South Korea to Marystown, Canada where installation of the topsides and hook up and commissioning will take place. The FPSO’s topside modules are currently being fabricated in St. John’s and Marystown, Newfoundland and Labrador.

Oil and Gas Reserves

Reserve Reconciliation									
	Canada					International		Total	
	Western Canada				East Coast				
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
Proved reserves, before royalties	*(mmbbls)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(bcf)*
Proved reserves at December 31, 2002	166.5	107.5	227.1	1,951.6	31.0	37.1	142.9	569.2	2,094.5
Revision of previous estimate	5.0	1.3	6.4	(131.6)	0.8	(4.5)	(142.9)	9.0	(274.5)
Purchase of reserves in place	9.3	-	2.8	183.9	-	-	-	12.1	183.9
Sales of reserves in place	(0.9)	(2.5)	(1.4)	(23.1)	-	-	-	(4.8)	(23.1)
Discoveries and extensions	5.4	1.9	28.4	301.0	-	-	-	35.7	301.0
Production	(11.8)	(14.3)	(36.5)	(222.9)	(6.1)	(8.2)	-	(76.9)	(222.9)
Proved reserves at December 31, 2003	**173.5**	**93.9**	**226.8**	**2,058.9**	**25.7**	**24.4**	**-**	**544.3**	**2,058.9**
Proved developed reserves, before royalties									
December 31, 2002	154.8	93.6	152.4	1,546.5	7.4	30.7	-	438.9	1,546.5
December 31, 2003	**158.5**	**85.8**	**156.2**	**1,712.4**	**17.2**	**24.4**	-	**442.1**	**1,712.4**

Western Canada

In Western Canada during 2003, Husky added 55.7 million barrels of crude oil and natural gas liquids reserves. Crude oil reserves additions were primarily in the Lloydminster heavy oil area and resulted from the extension of reservoirs through step-out drilling and revisions of previous estimates supported by better than expected well performance. Additions from the purchase of proved reserves primarily reflect the acquisition of Marathon Canada.

Natural gas reserve additions during 2003 totalled 330.2 billion cubic feet. The largest categories of natural gas reserve additions resulted from the extension of reservoirs and new discoveries. The largest of these additions were in the foothills and deep basin areas in northeastern British Columbia and Alberta. Additions from the purchase of proved reserves primarily reflect the acquisition of Marathon Canada. Revisions of previous reserve estimates of 131.6 billion cubic feet in Western Canada were, in large measure, undeveloped shallow gas reserves in the northern Alberta plains that were determined to be non-commercial due to the poor performance of offsetting wells. Positive revisions were recorded at Shackleton/Lacadena in southwestern Saskatchewan and at Ansell in the deep basin area of Alberta.

International

A revision of 142.9 billion cubic feet of proved natural gas reserves and 6.4 million barrels of natural gas liquids was related to the Madura Straits project in Indonesia. The revision reflected the uncertain status of achieving an extension to the production-sharing contract due to the unstable political and economic state of affairs in this area. This revision resulted in the addition of 47.7 billion cubic feet of natural gas reserves and 3.0 million barrels of natural gas liquids to probable reserves in Indonesia.

Operating Netbacks

Western Canada

Light Crude Oil Netbacks [1]

Per boe	Three months ended December 31 **2003**	2002	Year ended December 31 **2003**	2002
Sales revenues	**$ 35.48**	$ 36.71	**$ 39.91**	$ 33.66
Royalties	**6.38**	5.48	**7.28**	4.55
Hedging	**1.87**	(0.79)	**0.56**	(0.17)
Operating costs	**10.90**	13.10	**9.27**	10.46
Netback	**$ 16.33**	$ 18.92	**$ 22.80**	$ 18.82

Medium Crude Oil Netbacks [1]

Per boe	Three months ended December 31 **2003**	2002	Year ended December 31 **2003**	2002
Sales revenues	**$ 27.36**	$ 30.28	**$ 31.57**	$ 29.92
Royalties	**4.54**	6.73	**5.28**	5.59
Hedging	**3.83**	(0.79)	**1.79**	(0.19)
Operating costs	**9.47**	7.66	**9.53**	7.19
Netback	**$ 9.52**	$ 16.68	**$ 14.97**	$ 17.33

Heavy Crude Oil Netbacks [1]

Per boe	Three months ended December 31 **2003**	2002	Year ended December 31 **2003**	2002
Sales revenues	**$ 20.99**	$ 26.03	**$ 25.98**	$ 26.48
Royalties	**2.02**	4.10	**2.76**	3.45
Operating costs	**8.52**	8.41	**9.09**	7.18
Netback	**$ 10.45**	$ 13.52	**$ 14.13**	$ 15.85

Natural Gas Netbacks [2]

Per mcfge	Three months ended December 31 **2003**	2002	Year ended December 31 **2003**	2002
Sales revenues	**$ 4.90**	$ 4.98	**$ 5.79**	$ 3.97
Royalties	**0.98**	1.06	**1.29**	0.81
Hedging	**(0.20)**	-	**(0.08)**	-
Operating costs	**0.78**	0.74	**0.79**	0.70
Netback	**$ 3.34**	$ 3.18	**$ 3.79**	$ 2.46

Total Western Canada Upstream Netbacks [1]

Per boe	Three months ended December 31 **2003**	2002	Year ended December 31 **2003**	2002
Sales revenues	**$ 26.56**	$ 29.28	**$ 31.58**	$ 27.04
Royalties	**4.30**	5.49	**5.48**	4.46
Hedging	**0.24**	(0.21)	**0.14**	(0.05)
Operating costs	**7.40**	7.38	**7.56**	6.54
Netback	**$ 14.62**	$ 16.62	**$ 18.40**	$ 16.09

Terra Nova Crude Oil Netbacks				
	Three months ended December 31		Year ended December 31	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 38.21**	$ 37.22	**$ 38.91**	$ 35.47
Royalties	**0.95**	0.40	**0.81**	0.36
Hedging	**2.99**	-	**1.95**	-
Operating costs	**2.67**	3.37	**3.16**	3.62
Netback	**$ 31.60**	$ 33.45	**$ 32.99**	$ 31.49

Wenchang Crude Oil Netbacks				
	Three months ended December 31		Year ended December 31	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 40.27**	$ 46.59	**$ 41.45**	$ 44.36
Royalties	**5.13**	2.72	**3.80**	2.65
Operating costs	**2.71**	1.27	**1.94**	2.15
Netback	**$ 32.43**	$ 42.60	**$ 35.71**	$ 39.56

Total Upstream Segment Netbacks [(1)]				
	Three months ended December 31		Year ended December 31	
Per boe	**2003**	2002	**2003**	2002
Sales revenues	**$ 28.01**	$ 31.17	**$ 32.69**	$ 28.12
Royalties	**4.17**	4.98	**5.11**	4.20
Hedging	**0.37**	(0.18)	**0.23**	(0.05)
Operating costs	**6.87**	6.66	**6.92**	6.24
Netback	**$ 16.60**	$ 19.71	**$ 20.43**	$ 17.73

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

Finding and Development Costs

Western Canada (*Excludes oil sands and acquisitions/divestitures)*				
Year ended December 31	**2001-2003**	**2003**	2002	2001
Total capitalized costs *($ millions)*	**$ 3,019.1**	**$ 1,132.7**	$ 994.2	$ 892.2
Proved reserve additions and revisions *(mmboe)*	**284.3**	**76.6**	94.8	112.9
Average cost per boe	**$ 10.62**	**$ 14.79**	$ 10.49	$ 7.90

Production Replacement

Western Canada *(Excludes oil sands)*				
Year ended December 31	**2001-2003**	**2003**	2002	2001
Production *(mmboe)*	**299.4**	**99.7**	100.2	99.5
Proved reserve additions and revisions *(mmboe)*	**284.3**	**76.6**	94.8	112.9
Production replacement ratio *(excluding net acquisitions) (percent)*	**95**	**77**	95	113
Proved reserve additions and revisions *(including net acquisitions) (mmboe)*	**338.9**	**110.7**	81.2	147.0
Production replacement ratio *(including net acquisitions) (percent)*	**113**	**111**	81	148

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.

Western Canada *(Excludes oil sands)*				
Year ended December 31	**2001-2003**	**2003**	2002	2001
Operating netback *($/boe)*	**$ 16.60**	**$18.40**	$16.09	$ 15.30
Proved finding and development cost *($/boe)*	**$ 10.62**	**$14.79**	$10.49	$ 7.90
Recycle ratio	**1.56**	**1.24**	1.53	1.94

MIDSTREAM

Husky Lloydminster Upgrader

At the Husky Lloydminster Upgrader, engineering of debottleneck and on-stream reliability projects continued during the fourth quarter of 2003. These projects are expected to increase the plant's productive capacity from 77,000 barrels per day of synthetic crude oil and diluent production to 82,000 barrels per day.

Selected Operating Data					
		Three months ended December 31		Year ended December 31	
		2003	2002	**2003**	2002
Upgrading					
Upgrader throughput [(1)]	*(mbbls/day)*	**69.8**	72.8	**72.5**	65.4
Synthetic crude oil sales	*(mbbls/day)*	**62.2**	67.5	**63.6**	59.3
Upgrading differential	*($/bbl)*	**13.40**	13.06	**12.88**	10.81
Unit margin	*($/bbl)*	**13.60**	11.92	**13.51**	11.05
Unit operating cost [(2)]	*($/bbl)*	**7.03**	7.11	**7.77**	6.48
Infrastructure and Marketing					
Aggregate pipeline throughput	*(mbbls/day)*	**502**	476	**484**	457

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

REFINED PRODUCTS

Husky completed conversion of three marketing locations to Husky Markets during the fourth quarter of 2003, two in Calgary and one in Vancouver, which brings the total new Husky Markets in 2003 to 10.

StorePoint, an integrated point of sale system, has been installed in a total of 308 outlets to date.

Selected Operating Data					
		Three months ended December 31		Year ended December 31	
		2003	2002	**2003**	2002
Number of fuel outlets				**552**	571
Light oil sales per outlet	*(thousand litres/day)*			**10.8**	10.0
Light oil sales	*(million litres/day)*	**8.2**	7.9	**8.2**	7.7
Prince George refinery throughput	*(mbbls/day)*	**11.5**	10.9	**10.3**	10.1
Asphalt sales	*(mbbls/day)*	**19.7**	14.2	**22.0**	20.8
Lloydminster refinery throughput	*(mbbls/day)*	**26.1**	17.8	**25.7**	22.0

CONSOLIDATED BALANCE SHEETS

(millions of dollars)	**December 31 2003**	December 31 2002
Assets		
Current assets		
Cash and cash equivalents	**$ 3**	$ 306
Accounts receivable	**618**	572
Inventories	**211**	243
Prepaid expenses	**33**	23
	865	1,144
Property, plant and equipment - (full cost accounting)	**16,679**	14,450
Less accumulated depletion, depreciation and amortization	**5,994**	5,103
	10,685	9,347
Goodwill *(note 10)*	**120**	-
Other assets	**112**	84
	$ 11,782	$ 10,575
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans	**$ 71**	$ -
Accounts payable and accrued liabilities	**1,126**	794
Long-term debt due within one year *(note 4)*	**259**	421
	1,456	1,215
Long-term debt *(note 4)*	**1,439**	1,964
Other long-term liabilities	**390**	266
Future income taxes *(note 6)*	**2,608**	2,003
Commitments and contingencies *(note 7)*		
Shareholders' equity		
Capital securities and accrued return	**298**	364
Common shares *(note 5)*	**3,457**	3,406
Retained earnings	**2,134**	1,357
	5,889	5,127
	$ 11,782	$ 10,575
Common shares outstanding *(millions)* *(note 5)*	**422.2**	417.9

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

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of dollars, except per share amounts)	Three months ended December 31 *(unaudited)* **2003**	2002	Year ended December 31 **2003**	2002
Sales and operating revenues, net of royalties	**$ 1,800**	$ 1,697	**$ 7,658**	$ 6,384
Costs and expenses				
Cost of sales and operating expenses	**1,165**	1,001	**4,825**	4,009
Selling and administration expenses	**33**	27	**119**	94
Depletion, depreciation and amortization	**293**	256	**1,058**	939
Interest - net *(note 4)*	**16**	25	**73**	104
Foreign exchange *(note 4)*	**(43)**	(5)	**(215)**	13
Other - net	**1**	1	**3**	1
	1,465	1,305	**5,863**	5,160
Earnings before income taxes	**335**	392	**1,795**	1,224
Income taxes *(note 6)*				
Current	**22**	6	**147**	66
Future	**68**	144	**327**	354
	90	150	**474**	420
Net earnings	**$ 245**	$ 242	**$ 1,321**	$ 804
Earnings per share *(note 9)*				
Basic	**$ 0.62**	$ 0.57	**$ 3.23**	$ 1.88
Diluted	**$ 0.62**	$ 0.57	**$ 3.22**	$ 1.88
Weighted average number of common shares outstanding *(millions)* *(note 9)*				
Basic	**421.7**	417.7	**419.5**	417.4
Diluted	**423.8**	419.6	**421.5**	419.3

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(millions of dollars)	Three months ended December 31 *(unaudited)* **2003**	2002	Year ended December 31 **2003**	2002
Beginning of period	**$ 1,915**	$ 1,158	**$ 1,357**	$ 722
Net earnings	**245**	242	**1,321**	804
Dividends on common shares - ordinary	**(42)**	(38)	**(160)**	(151)
- special	**-**	-	**(420)**	-
Return on capital securities (net of related taxes and foreign exchange)	**16**	(5)	**36**	(18)
End of period	**$ 2,134**	$ 1,357	**$ 2,134**	$ 1,357

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of dollars)	Three months ended December 31 *(unaudited)* **2003**	2002	Year ended December 31 **2003**	2002
Operating activities				
Net earnings	**$ 245**	$ 242	**$ 1,321**	$ 804
Items not affecting cash				
Depletion, depreciation and amortization	**293**	256	**1,058**	939
Future income taxes	**68**	144	**327**	354
Foreign exchange	**(37)**	(7)	**(242)**	-
Other	**(1)**	-	**(5)**	(1)
Cash flow from operations	**568**	635	**2,459**	2,096
Change in non-cash working capital *(note 8)*	**(40)**	(48)	**113**	(204)
Cash flow - operating activities	**528**	587	**2,572**	1,892
Financing activities				
Bank operating loans financing - net	**71**	-	**71**	(100)
Long-term debt issue	**598**	-	**598**	972
Long-term debt repayment	**(815)**	(23)	**(971)**	(678)
Settlement of cross currency swap	**(32)**	-	**(32)**	-
Return on capital securities payment	**-**	-	**(29)**	(31)
Debt issue costs	**-**	-	**-**	(9)
Proceeds from exercise of stock options	**13**	4	**51**	9
Proceeds from interest swaps monetization	**-**	-	**44**	-
Dividends on common shares	**(42)**	(38)	**(580)**	(151)
Change in non-cash working capital *(note 8)*	**(191)**	139	**48**	(9)
Cash flow - financing activities	**(398)**	82	**(800)**	3
Available for investing	**130**	669	**1,772**	1,895
Investing activities				
Capital expenditures	**(627)**	(479)	**(1,905)**	(1,692)
Corporate acquisitions	**(809)**	(3)	**(809)**	(3)
Asset sales	**459**	11	**511**	93
Other	**2**	(2)	**5**	(20)
Change in non-cash working capital *(note 8)*	**118**	(30)	**123**	33
Cash flow - investing activities	**(857)**	(503)	**(2,075)**	(1,589)
Increase (decrease) in cash and cash equivalents	**(727)**	166	**(303)**	306
Cash and cash equivalents at beginning of period	**730**	140	**306**	-
Cash and cash equivalents at end of period	**$ 3**	$ 306	**$ 3**	$ 306

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Year ended December 31, 2003

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

Note 1 Segmented Financial Information

	Upstream		Midstream Upgrading		Midstream 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 December 31												
(unaudited)												
Sales and operating revenues, net of royalties	**$ 722**	$ 781	**$ 229**	$ 301	**$1,139**	$1,367	**$ 335**	$ 326	**$ (625)**	$ (1,078)	**$ 1,800**	$ 1,697
Costs and expenses												
Operating, cost of sales, selling and general	**221**	206	**196**	265	**1,089**	1,321	**318**	318	**(625)**	(1,081)	**1,199**	1,029
Depletion, depreciation and amortization	**267**	231	**5**	5	**6**	6	**8**	9	**7**	5	**293**	256
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**16**	25	**16**	25
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(43)**	(5)	**(43)**	(5)
	488	437	**201**	270	**1,095**	1,327	**326**	327	**(645)**	(1,056)	**1,465**	1,305
Earnings (loss) before income taxes	**234**	344	**28**	31	**44**	40	**9**	(1)	**20**	(22)	**335**	392
Current income taxes	**5**	26	**1**	-	**22**	(19)	**(13)**	(1)	**7**	-	**22**	6
Future income taxes	**55**	108	**9**	11	**(6)**	31	**17**	1	**(7)**	(7)	**68**	144
Net earnings (loss)	**$ 174**	$ 210	**$ 18**	$ 20	**$ 28**	$ 28	**$ 5**	$ (1)	**$ 20**	$ (15)	**$ 245**	$ 242
Year ended December 31												
Sales and operating revenues, net of royalties	**$3,186**	$2,665	**$1,013**	$ 909	**$4,946**	$4,230	**$1,502**	$1,310	**$ (2,989)**	$ (2,730)	**$ 7,658**	$ 6,384
Costs and expenses												
Operating, cost of sales, selling and general	**855**	729	**901**	811	**4,747**	4,038	**1,422**	1,222	**(2,978)**	(2,696)	**4,947**	4,104
Depletion, depreciation and amortization	**958**	851	**20**	18	**21**	20	**34**	34	**25**	16	**1,058**	939
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**73**	104	**73**	104
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(215)**	13	**(215)**	13
	1,813	1,580	**921**	829	**4,768**	4,058	**1,456**	1,256	**(3,095)**	(2,563)	**5,863**	5,160
Earnings (loss) before income taxes	**1,373**	1,085	**92**	80	**178**	172	**46**	54	**106**	(167)	**1,795**	1,224
Current income taxes	**95**	55	**1**	1	**27**	6	**9**	4	**15**	-	**147**	66
Future income taxes	**230**	342	**20**	25	**37**	59	**9**	18	**31**	(90)	**327**	354
Net earnings (loss)	**$1,048**	$ 688	**$ 71**	$ 54	**$ 114**	$ 107	**$ 28**	$ 32	**$ 60**	$ (77)	**$ 1,321**	$ 804
Capital employed - As at December 31	**$6,652**	$6,040	**$ 456**	$ 319	**$ 350**	$ 431	**$ 320**	$ 338	**$ (120)**	$ 384	**$ 7,658**	$ 7,512
Total assets - As at December 31 (2)	**$9,806**	$8,220	**$ 649**	$ 658	**$ 701**	$ 850	**$ 525**	$ 534	**$ 101**	$ 313	**$11,782**	$ 10,575

(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) *2003 includes goodwill on Marathon Canada Limited acquisition related to Upstream.*

Note 2 Significant Accounting Policies

The interim consolidated financial statements of Husky Energy Inc. 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. Certain prior years' amounts have been reclassified to conform with current presentation.

Note 3 Financial Instruments and Risk Management

Upstream Commodity Price Risk
The Company hedged crude oil averaging 85,000 bbls/day from January to December 2004 at an average fixed WTI price of U.S. $27.46/bbl.

The Company hedged natural gas averaging 70 mmcf/day for February and March 2004 at an average NYMEX price of $6.69/mcf and 20 mmcf/day for April 2004 at an average NYMEX price of $6.38/mcf.

Power Consumption Price Risk
In 2003, the Company hedged power consumption of 329,400 MWh from January to December 2004 at an average fixed price of $46.72/MWh.

Foreign Currency Rate Risk
At December 31, 2003 the Company had the following cross currency debt swaps:

Debt	Swap Amount	Swap Maturity	Interest Rate	Canadian Equivalent
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 December 31, 2003:

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

During 2003, the Company unwound the following interest rate swaps:

Debt	Swap Amount	Swap Maturity	Gross Proceeds
6.875% notes	U.S. $35	November 15, 2003	$ 3
7.125% notes	U.S. $150	November 15, 2006	$ 18
6.25% notes	U.S. $150	June 15, 2012	$ 23

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

Sale of Accounts Receivable
In November 2003, the Company established a securitization program to sell, on a revolving basis, up to $250 million of accounts receivable to a third party. As at December 31, 2003, $250 million in outstanding accounts receivable had been sold under the program. The agreement includes a program fee based on Canadian commercial paper rates.

Note 4 Long-term Debt

			Maturity	Dec. 31 2003	Dec. 31 2002
Long-term debt					
6.25% notes	-2003 & 2002	*U.S. $400*	2012	**$ 517**	$ 632
6.875% notes	-2002	*U.S. $150*		**-**	237
7.125% notes	-2003 & 2002	*U.S. $150*	2006	**194**	237
7.55% debentures	-2003 & 2002	*U.S. $200*	2016	**258**	316
8.45% senior secured bonds	-2003	*U.S. $145*			
	-2002	*U.S. $162*	2004-12	**188**	256
Private placement notes	-2003	*U.S. $32*			
	-2002	*U.S. $68*	2004-5	**41**	107
Medium-term notes			2004-9	**500**	600
Total long-term debt				**1,698**	2,385
Amount due within one year				**(259)**	(421)
				$ 1,439	$ 1,964

At December 31, 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 December 31		Year ended December 31	
	2003	2002	**2003**	2002
Long-term debt	**$ 30**	$ 33	**$ 129**	$ 128
Short-term debt	**1**	1	**2**	3
	31	34	**131**	131
Amount capitalized	**(15)**	(9)	**(52)**	(26)
	16	25	**79**	105
Interest income	**-**	-	**(6)**	(1)
	$ 16	$ 25	**$ 73**	$ 104

Foreign exchange consisted of:

	Three months ended December 31		Year ended December 31	
	2003	2002	**2003**	2002
Gain on translation of U.S. dollar denominated long-term debt	**$ (60)**	$ (7)	**$ (315)**	$ -
Cross currency swaps	**23**	-	**73**	-
Other losses (gains)	**(6)**	2	**27**	13
	$ (43)	$ (5)	**$ (215)**	$ 13

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:

	Year ended December 31			
	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	4,302,141	51	995,508	9
Balance at December 31	**422,175,742**	**$ 3,457**	417,873,601	$ 3,406

The Company follows the intrinsic value method of accounting for stock-based compensation for its 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 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 December 31		Year ended December 31	
	2003	2002	**2003**	2002
Weighted average fair market value per option	**$ 4.29**	$ 4.10	**$ 4.00**	$ 5.19
Risk-free interest rate *(percent)*	**3.7**	3.9	**3.9**	3.6
Volatility *(percent)*	**19**	29	**23**	43
Expected life *(years)*	**5**	5	**5**	5
Expected annual dividend per share	**$ 0.40**	$ 0.36	**$ 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 share options granted prior to September 3, 2003 were revalued at the modification date using the 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 year ended December 31, 2003, additional compensation costs of $71 thousand and $3.6 million respectively, 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 December 31		Year ended December 31	
	2003	2002	**2003**	2002
Compensation cost - options granted after January 1, 2002 [(1)]	**$ 1**	$ -	**$ 5**	$ -
Compensation cost - all options granted [(1)]	**$ 1**	$ (1)	**$ 14**	$ 13
Net earnings available to common shareholders				
As reported	**$ 261**	$ 238	**$ 1,356**	$ 787
Options granted after January 1, 2002	**$ 260**	$ 238	**$ 1,351**	$ 787
All options granted	**$ 260**	$ 239	**$ 1,342**	$ 774
Weighted average number of common shares outstanding *(millions)*				
Basic	**421.7**	417.7	**419.5**	417.4
Diluted	**423.8**	419.6	**421.5**	419.3
Basic earnings per share				
As reported	**$ 0.62**	$ 0.57	**$ 3.23**	$ 1.88
Options granted after January 1, 2002	**$ 0.62**	$ 0.57	**$ 3.22**	$ 1.88
All options granted	**$ 0.62**	$ 0.57	**$ 3.20**	$ 1.86
Diluted earnings per share				
As reported	**$ 0.62**	$ 0.57	**$ 3.22**	$ 1.88
Options granted after January 1, 2002	**$ 0.61**	$ 0.57	**$ 3.21**	$ 1.88
All options granted	**$ 0.61**	$ 0.57	**$ 3.18**	$ 1.85

[(1)] *Includes options modified.*

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 issuance of shares.

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

	Year ended December 31			
	2003		2002	
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	591	$19.17	568	$16.11
Exercised	(3,789)	$13.45	(608)	$13.63
Forfeited	(125)	$14.71	(642)	$14.37
Outstanding, December 31	**4,597**	**$13.88**	7,920	$13.91
Options exercisable at December 31	3,564	$12.93	4,822	$13.72

At December 31, 2003, the options outstanding had exercise prices ranging from $10.34 to $22.01 with a weighted average contractual life of 2.2 years.

Note 6 Income Taxes

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 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 for the year ended December 31, 2002 included an adjustment to future income taxes of $31 million resulting from reductions to the British Columbia and Alberta corporate income tax rates and a reduction in the federal corporate income tax rate for non-resource income.

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 December 31, 2003 was $1.2 billion. As at December 31, 2003, the Company had spent $655 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 December 31		Year ended December 31	
	2003	2002	**2003**	2002
a) Changes in non-cash working capital were as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 188**	$ 161	**$ (7)**	$ (153)
Inventories	**36**	(2)	**31**	(17)
Prepaid expenses	**35**	9	**(10)**	1
Accounts payable and accrued liabilities	**(372)**	(107)	**270**	(11)
Change in non-cash working capital	**(113)**	61	**284**	(180)
Relating to:				
Financing activities	**(191)**	139	**48**	(9)
Investing activities	**118**	(30)	**123**	33
Operating activities	**$ (40)**	$ (48)	**$ 113**	$ (204)
b) Other cash flow information:				
Cash taxes paid	**$ 2**	$ -	**$ 69**	$ 20
Cash interest paid	**$ 49**	$ 45	**$ 134**	$ 139

Note 9 Net Earnings Per Common Share

	Three months ended December 31		Year ended December 31	
	2003	2002	**2003**	2002
Net earnings	**$ 245**	$ 242	**$ 1,321**	$ 804
Return on capital securities (net of related taxes and foreign exchange)	**16**	(4)	**35**	(17)
Net earnings available to common shareholders	**$ 261**	$ 238	**$ 1,356**	$ 787
Weighted average number of common shares outstanding - Basic *(millions)*	**421.7**	417.7	**419.5**	417.4
Effect of dilutive stock options and warrants	**2.1**	1.9	**2.0**	1.9
Weighted average number of common shares outstanding - Diluted *(millions)*	**423.8**	419.6	**421.5**	419.3
Earnings per share - Basic	**$ 0.62**	$ 0.57	**$ 3.23**	$ 1.88
- Diluted	**$ 0.62**	$ 0.57	**$ 3.22**	$ 1.88

Note 10 Acquisition of Marathon Canada

Effective October 1, 2003 the Company acquired all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. ("Marathon Canada") for cash consideration of U.S. $611 million (Cdn. $831 million). The results of Marathon Canada 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 Marathon Canada's net assets acquired at October 1, 2003 was as follows:

	Allocation
Net assets acquired	
Working capital [(1)]	$ 5
Property, plant and equipment	1,008
Goodwill [(2)]	120
Site restoration	(38)
Future income taxes	(264)
	$ 831

(1) *Working capital acquired includes cash of $22 million.*

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

In conjunction with the above acquisition of Marathon Canada, the Company sold certain of the Marathon Canada oil and gas properties to a third party for cash consideration of U.S. $320 million (Cdn. $431 million).

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.

Notice Regarding Forward-looking Statements

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 fulfil 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.

Non GAAP Disclosures

This news release contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with generally accepted accounting principles ("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 consolidated cash flow from operations are considered to be a corporate responsibility.

Husky Energy will host a conference call for analysts and investors on Wednesday, February 4, 2004 at 4:15 p.m. Eastern time to discuss Husky's fourth quarter and year-end results.

To participate, please dial 1 (800) 640-7112 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) 701-7176 beginning at 4:05 p.m.

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 21182087. The PostView will be available until Friday, March 5, 2004.

For further information, please contact:

Mr. Colin Luciuk
Manager, Investor Relations
Husky Energy Inc.
TEL: (403) 750-4938

Mr. Rocco Ciancio
Manager, Corporate Communications
Husky Energy Inc.
TEL: (403) 298-7088