HUSKY ENERGY INC. | TSE SYMBOL

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For Immediate Release
October 30, 2002

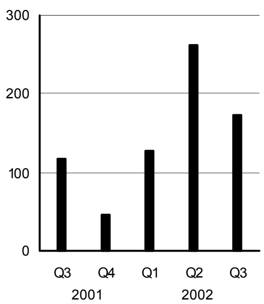
LOOKING BEYOND THE HORIZON

QUARTERLY REPORT FOR THE PERIOD ENDING SEPTEMBER 30, 2002

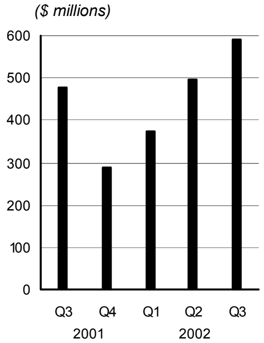
Lloydminster Upgrader

Husky Energy Inc. Reports Increased Oil Production, Higher Net Earnings and Cash Flow

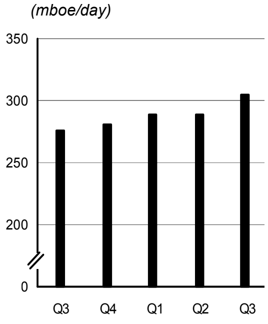
Net Earnings
($ millions – 2001 amounts as restated)



Cash Flow from Operations
($ millions)



Total Production
(mboe/day)



Calgary, Alberta – Husky Energy Inc. ("Husky") today reported net earnings of $173 million ($0.38 per share) in the third quarter of 2002, a 47 percent increase compared to $118 million ($0.24 per share) in the same quarter of 2001. Earnings were reduced by $53 million ($0.15 per share) on foreign exchange translation of U.S. dollar denominated debt compared to $43 million ($0.13 per share) in the third quarter of 2001. Cash flow from operations in the third quarter of 2002 was $590 million ($1.39 per share), a 23 percent increase compared to $478 million ($1.12 per share) in the same quarter of 2001.

The difference in net earnings in the third quarter of 2002 compared to the same quarter in 2001 was due to increased oil production and an improvement in commodity prices. Husky's production in the third quarter increased more than 10 percent compared to the same period last year due to the commencement of the Wenchang oil project in the south China sea on July 7 and Terra Nova, which achieved first oil earlier this year. Production averaged about 305,100 boe/day in the third quarter compared to 276,300 boe/day in the same quarter last year.

"Our increasing production surpassed 300,000 boe/day strengthening our cash flow and positioning us to develop new opportunities," said Mr. John C.S. Lau, President and Chief Executive Officer. "We continue to focus our attention on large projects such as White Rose, Tucker thermal project and our exploration opportunities in the south China sea to create a strong future for the Company."

Husky's net earnings for the first nine months of 2002 were $562 million ($1.31 per share) compared to $609 million ($1.39 per share) in the first nine months of 2001. Net earnings were reduced by $5 million ($0.01 per share) on foreign currency translation of U.S. dollar denominated debt compared to $55 million ($0.16 per share) in the first nine months of 2001. Cash flow from operations in the first nine months was $1,461 million ($3.43 per share), compared to $1,659 million ($3.91 per share) for the first nine months of 2001. Lower net earnings and cash flow reflect lower natural gas prices, which were partially offset by higher crude prices and production increases.

Husky Energy

Highlights

(millions of dollars, except per share amounts)	Three months ended September 30 2002	2001[1]		% Change	Nine months ended September 30 2002	2001[1]		% Change
Sales and operating revenues, net of royalties	**$ 1,669**	$ 1,470	⇧	14	**$ 4,687**	$ 4,981	⇩	6
EBITDA[2]	**564**	451	⇧	25	**1,594**	1,680	⇩	5
Cash flow from operations	**590**	478	⇧	23	**1,461**	1,659	⇩	12
Per share - Basic	**1.39**	1.13	⇧	23	**3.44**	3.93	⇩	12
- Diluted	**1.39**	1.12	⇧	24	**3.43**	3.91	⇩	12
Upstream	**$ 347**	$ 201			**$ 768**	$ 816		
Midstream	**50**	69			**183**	303		
Refined Products	**32**	53			**64**	107		
Corporate and eliminations	**(29)**	(21)			**(86)**	(60)		
Foreign exchange	**(75)**	(56)			**(18)**	(79)		
Operating profit[3]	**325**	246			**911**	1,087		
Interest - net	**(28)**	(24)			**(79)**	(78)		
Income taxes	**(124)**	(104)			**(270)**	(400)		
Net earnings	**$ 173**	$ 118	⇧	47	**$ 562**	$ 609	⇩	8
Per share - Basic	**$ 0.38**	$ 0.25	⇧	52	**$ 1.31**	$ 1.40	⇩	6
- Diluted	**0.38**	0.24	⇧	58	**1.31**	1.39	⇩	6
Dividend paid per share	**0.09**	0.09		-	0.27	0.27		-
Daily production, before royalties								
Light/medium crude oil & NGL *(mbbls/day)*	**131.4**	112.7	⇧	17	**121.9**	112.2	⇧	9
Lloydminster heavy crude oil *(mbbls/day)*	**80.0**	69.1	⇧	16	**77.9**	62.2	⇧	25
Natural gas *(mmcf/day)*	**561.6**	567.1	⇩	1	**566.5**	573.9	⇩	1
Barrels of oil equivalent (6:1) *(mboe/day)*	**305.1**	276.3	⇧	10	**294.3**	270.1	⇧	9

(1) 2001 amounts as restated. Refer to note 3 to the consolidated financial statements.
(2) Earnings from operations before interest, income taxes and depletion, depreciation and amortization. Refer to note 1 to the consolidated financial statements for derivation of this number.
(3) Earnings from operations before interest and income taxes.

Highlights

UPSTREAM

Production

Husky's production during the third quarter of 2002 averaged 305,100 boe/day, an increase of approximately 10 percent compared to the third quarter of 2001. Higher production of crude oil was due to the commencement of production from the Wenchang and Terra Nova oil fields and increased Lloydminster heavy oil production. Production from Wenchang averaged 21,900 bbls/day (net to Husky) and Terra Nova averaged 10,800 bbls/day (net to Husky). Heavy oil production averaged 80,000 bbls/day during the third quarter of 2002, compared to 69,100 bbls/day in the same quarter last year. Western Canada production decreased by 1,200 boe/day to 272,200 boe/day in the third quarter of 2002 compared to the second quarter of 2002 due to natural declines and limited drilling and tie-in activity because of summer access restrictions.

The expansion of the Bolney/Celtic Thermal project is on track to commence in the fourth quarter of 2002 and will utilize 6,000 bbls/day of excess plant capacity. Drilling was completed on eight Celtic horizontal steam assisted gravity drainage pairs and steam injection began in September. A regulatory application to increase Bolney/Celtic area capacity to 16,000 bbls/day from 11,000 bbls/day was submitted in September.

Husky has acquired an additional 210 sections of land for the Shackleton gas play in southern Saskatchewan and drilled 25 stepout wells in the third quarter. The Company is proceeding with a 145 well development drilling program. Tie-ins for 170 wells to two new gas plants is planned for fourth quarter and full phase l production of 20 mmcf/day is scheduled for November, 2002.

As part of its asset rationalization program the Company completed a southern Alberta and Saskatchewan asset sale in September, 2002 of non-core properties producing 8,000 boe/day.

Exploration

Western Canada
During the third quarter of 2002, Husky drilled 24 net exploration wells with a success rate of 92 percent. During the first nine months of the year, the Company drilled 823 net wells with a success rate of 94 percent. The 2002/2003 exploration program will target northeast British Columbia, the foothills along the eastern slopes of the Rocky Mountains and the deep basin portion of Western Canada.

East Coast, Canada Offshore
Husky proceeded with an east coast exploration program during the quarter, drilling two wells in the Jeanne d'Arc basin. Drilling of a test well on the Trepassey exploration licence (EL 1044) commenced in July and a test well at Gros Morne (EL 1055) commenced in September. The wells are located approximately 10 and 15 kilometres, respectively, south of Whiterose. Both structures were water bearing in the main reservoir zone. At Trepassey, hydrocarbons were encountered in a secondary zone, although not in commercial quantities. The results of both wells will help the Company develop its future strategies in the area.

Major Project Update

International Offshore - China

Wenchang

Husky reported September 23, 2002 that oil production from the Wenchang project in the south China sea has exceeded expectations. Prior to first oil, Husky anticipated peak production to be 50,000 bbls/day (20,000 net to Husky). Production commenced July 7, 2002 and has reached peak rates in excess of 60,000 bbls/day (24,000 net to Husky). Husky has a 40 percent interest in the project.

Husky has announced plans to proceed with exploration drilling in the 39/05 exploration licence near the Wenchang project. The drilling is expected to commence in the fourth quarter of 2002 or first quarter of 2003. The Company also signed petroleum contracts to explore two other exploration blocks in the south China sea. Both are located in the Beibu Gulf, north of Hainan Island and near the Weizhou oil fields.

East Coast, Canada Offshore

Terra Nova

Husky's share of production averaged 10,800 bbls/day during the quarter. Husky has a 12.51 percent working interest in the project. The project had a 25-day scheduled turnaround in August.

White Rose

Husky announced in September that it awarded a $250 million contract for the subsea production system for the White Rose offshore project, located in the Jeanne d'Arc basin approximately 350 kilometres east of Newfoundland. The contract covers the design, supply and installation of the subsea system that will produce oil and connect to the project's floating production, storage and offloading vessel. White Rose received project sanction in the first quarter of 2002, and first oil is scheduled to commence prior to the end of 2005.

Oil Sands - Alberta

Tucker

Husky initiated the public disclosure process for the Tucker thermal project on September 16, 2002. The proposed project, to be located about 30 kilometres west of Cold Lake, would produce about 30,000 bbls/day for 25 years. Husky proposes to use steam assisted gravity drainage technology to develop the estimated 250 mmbbl resource, and production is expected in the first quarter of 2006. Husky will continue to work with stakeholders to prepare the project for regulatory approvals in 2003.

MIDSTREAM

Two cargoes of Terra Nova crude, totalling 1.25 mmbbls, were lifted in the quarter for sale to buyers in Canada and the U.S. Husky lifted two cargoes of Wenchang crude, totalling 1.3 mmbbls, that were sold for delivery to markets in China.

REFINED PRODUCTS

Husky continued its efforts to enhance its retail market presence, opening a new Car/Truck Stop facility in Saskatoon and a new independent Car/Truck Stop in Toronto. Construction of a new Husky Market convenience store was started at Whistler, British Columbia with an additional eight other Husky Market sites in the development permit stage. An agreement was also signed with T-Chek, the second largest fueling card system operator in the U.S. to accept their cards throughout the Husky cardlock system. Husky completed a program to replace regular unleaded fuel with ethanol blended fuel at all Husky and Mohawk stations in Saskatchewan.

Asphalt sales volume established new records in July and August. Husky's third quarter 2002 shipments were 1,913,000 bbls, compared to 1,819,000 bbls in the same quarter last year. Shipments for the first nine months of 2002 were 3,900,000 bbls, compared to 3,600,000 bbls a year ago.

Management's Discussion & Analysis

The following management's discussion and analysis should be read in conjunction with the unaudited consolidated financial statements of the Company for the nine months ended September 30, 2002 and the audited consolidated financial statements and management's discussion and analysis for the year ended December 31, 2001, as restated. All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.

The calculation of barrels of oil equivalent ("boe") and thousands of cubic feet equivalent ("mcfe") are based on a conversion rate of six thousand cubic feet of natural gas for one barrel of crude oil. All comparisons refer to the third quarter of 2002 compared with the third quarter of 2001 and the first nine months of 2002 compared with the first nine months of 2001, unless otherwise indicated. All production volumes quoted are the Company's working interest share (net), unless otherwise indicated.

Management's Discussion and Analysis contains certain terms such as earnings before interest, taxes, depletion, depreciation and amortization ("EBITDA"), earnings before interest and taxes ("Operating profit") and cash flow from operations. These measurements should not be considered an alternative to, or more meaningful than, net earnings or cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as indicators of the Company's financial performance or liquidity. Husky's determination of EBITDA, operating profit and cash flow from operations may not be comparable to those reported by other companies. EBITDA, operating profit and cash flow from operations represent measurements of financial performance to which each reporting business segment is responsible. The other items required to arrive at net earnings or cash flow are considered to be corporate in nature.

Quarterly Comparison [1]

		Three months ended				
		Sept. 30 2002	June 30 2002	March 31 2002	Dec. 31 2001	Sept. 30 2001
Sales and operating revenues, net of royalties		**$ 1,669**	$ 1,659	$ 1,359	$ 1,615	$ 1,470
EBITDA		**564**	599	431	302	451
Cash flow from operations		**590**	498	373	287	478
Per share - Basic		**1.39**	1.18	0.88	0.67	1.13
- Diluted		**1.39**	1.17	0.87	0.66	1.12
Net earnings		**173**	263	126	45	118
Per share - Basic		**0.38**	0.64	0.29	0.09	0.25
- Diluted		**0.38**	0.64	0.29	0.09	0.24
Daily production, before royalties						
Light/medium crude oil & NGL	*(mbbls/day)*	**131.4**	116.6	117.5	111.3	112.7
Lloydminster heavy crude oil	*(mbbls/day)*	**80.0**	76.9	76.9	75.0	69.1
Natural gas	*(mmcf/day)*	**561.6**	571.8	566.0	568.7	567.1
Barrels of oil equivalent (6:1)	*(mboe/day)*	**305.1**	288.9	288.7	281.1	276.3

[1] 2001 amounts as restated. Refer to note 3 to the consolidated financial statements.

Third quarter 2002 net earnings of $173 million ($0.38 per share - basic & diluted) were 47 percent higher than the $118 million ($0.24 per share - diluted) reported for the third quarter of 2001. The higher earnings primarily resulted from higher prices for crude oil and natural gas, higher production of crude oil and higher commodity marketing profits. These positive factors were partially offset by lower upgrader throughput and margins, lower income from pipeline and asphalt operations, higher depletion, depreciation and amortization expense, higher foreign exchange losses due to foreign exchange translation on U.S. dollar denominated debt and higher income tax expense. Higher production of crude oil was attributable to Lloydminster heavy crude oil operations and light crude oil from the Terra Nova oil field offshore the east coast of Canada and the Wenchang oil field offshore south China. Higher production from Lloydminster resulted from successful exploitation programs that have increased production by 16 percent over the third quarter of 2001. Production from Terra Nova, which commenced in January 2002, and Wenchang, which commenced in July 2002, more than offset lower light/medium crude oil production in Western Canada. Husky's production volumes were 305 mboe/day during the third quarter of 2002 compared with 276 mboe/day during the third quarter of 2001, an increase of 10 percent and a six percent increase from 289 mboe/day in the second quarter of 2002.

2002 PRODUCTION FORECAST

Husky provided its production forecast for 2002 in the Second Quarter Report issued on August 1, 2002. Overall production is expected to average between 295 and 315 mboe/day. Husky expects production of light and medium crude oil and NGL will average between 125 and 135 mbbls/day. Lloydminster heavy crude oil production is expected to average between 77 and 80 mbbls/day. Natural gas production is expected to average between 570 and 600 mmcf/day.

Industry Conditions

		Three months ended September 30		Nine months ended September 30	
Benchmark Prices (averages)		**2002**	2001	**2002**	2001
West Texas Intermediate ("WTI")	*(U.S. $/bbl)*	**$ 28.27**	$ 26.76	**$ 25.39**	$ 27.81
NYMEX natural gas	*(U.S. $/mmbtu)*	**$ 3.26**	$ 2.98	**$ 3.01**	$ 5.01
AECO natural gas	*($/GJ)*	**$ 3.08**	$ 3.72	**$ 3.48**	$ 6.92
WTI/Lloyd Blend differential	*(U.S. $/bbl)*	**$ 5.99**	$ 8.32	**$ 5.92**	$ 10.95
U.S./Canadian dollar exchange rate	*(U.S. $)*	**$ 0.640**	$ 0.647	**$ 0.637**	$ 0.650

During the third quarter of 2002 the near-month price for West Texas Intermediate ("WTI") rose steadily averaging over U.S. $27/bbl in July, U.S. $28/bbl in August and U.S. $29/bbl in September. The near-month price of WTI continued to rise into October, averaging U.S. $29.75/bbl in the first two weeks.

The NYMEX near-month price for natural gas fluctuated just below U.S. $3.00/mmbtu throughout July and the first half of August before breaking through the U.S. $3.00/mmbtu mark to average U.S. $3.48/mmbtu during the remainder of the quarter. During the first two weeks of October the near-month price for natural gas averaged U.S. $3.95/mmbtu.

The Company's management believes that commodity prices will likely remain volatile and uncertain.

Results of Operations

UPSTREAM

Revenues and Production

Husky's upstream operating profit increased $146 million (73 percent) to $347 million in the third quarter of 2002 from $201 million in the third quarter of 2001. Husky's net revenues from upstream operations (after royalties and hedging) increased $189 million (34 percent) to $738 million from $549 million. During the first nine months of 2002 upstream operating profit decreased by $48 million (six percent) to $768 million from $816 million in the same period of 2001. Total net revenues from upstream operations increased $86 million (five percent) in the first nine months of 2002 to $1,884 million from $1,798 million in the same period in 2001.

Upstream Earnings Summary [1]

	Three months ended September 30		Nine months ended September 30	
	2002	2001	**2002**	2001
Gross revenues	**$ 862**	$ 661	**$ 2,198**	$ 2,231
Royalties	**124**	112	**314**	433
Net revenues	**738**	549	**1,884**	1,798
Costs and expenses	**173**	163	**496**	447
EBITDA	**565**	386	**1,388**	1,351
Depletion, depreciation and amortization (“DD&A”)	**218**	185	**620**	535
Operating profit	**$ 347**	$ 201	**$ 768**	$ 816

[1] *2001 amounts as restated. Refer to note 3 to the consolidated financial statements.*

Net Revenue Variance Analysis [1]

	Light/medium crude oil & NGL	Lloydminster heavy crude oil	Natural gas	Other	Total
Three months ended September 30, 2001	$ 263	$ 135	$ 138	$ 13	$ 549
Price changes	60	54	9	3	126
Volume changes	55	24	(2)	-	77
Royalties	(2)	(15)	3	-	(14)
Three months ended September 30, 2002	**$ 376**	**$ 198**	**$ 148**	**$ 16**	**$ 738**
Nine months ended September 30, 2001	$ 738	$ 276	$ 757	$ 27	$ 1,798
Price changes	74	176	(431)	5	(176)
Volume changes	78	78	(13)	-	143
Royalties	14	(27)	131	-	118
Processing	-	-	-	1	1
Nine months ended September 30, 2002	**$ 904**	**$ 503**	**$ 444**	**$ 33**	**$ 1,884**

[1] *2001 amounts as restated. Refer to note 3 to the consolidated financial statements.*

Average Realized Prices

		Three months ended September 30		Nine months ended September 30	
		2002	2001	**2002**	2001
Light/medium crude oil & NGL	*($/bbl)*	**$ 36.72**	$ 31.74	**$ 31.99**	$ 29.79
Lloydminster heavy crude oil	*($/bbl)*	**$ 30.94**	$ 23.65	**$ 26.32**	$ 18.05
Natural gas	*($/mcf)*	**$ 3.42**	$ 3.25	**$ 3.50**	$ 6.29

Royalty Rates				
	Three months ended September 30		Nine months ended September 30	
Percentage of upstream sales revenues, before royalties	**2002**	2001	**2002**	2001
Light/medium crude oil & NGL	**15%**	20%	**15%**	19%
Lloydminster heavy crude oil	**13%**	10%	**10%**	10%
Natural gas	**16%**	18%	**18%**	23%
Total	**15%**	17%	**14%**	20%

Daily Production, Before Royalties					
		Three months ended September 30		Nine months ended September 30	
		2002	2001	**2002**	2001
Light/medium crude oil & NGL	*(mbbls/day)*	**131.4**	112.7	**121.9**	112.2
Lloydminster heavy crude oil	*(mbbls/day)*	**80.0**	69.1	**77.9**	62.2
Natural gas	*(mmcf/day)*	**561.6**	567.1	**566.5**	573.9
Barrels of oil equivalent (6:1)	*(mboe/day)*	**305.1**	276.3	**294.3**	270.1

Product Mix				
	Three months ended September 30		Nine months ended September 30	
Percentage of upstream sales revenues, net of royalties	**2002**	2001	**2002**	2001
Light/medium crude oil & NGL	**52%**	49%	**48%**	42%
Lloydminster heavy crude oil	**27%**	24%	**27%**	15%
Natural gas	**21%**	27%	**25%**	43%
	100%	100%	**100%**	100%

The increase in upstream revenues for the third quarter of 2002 compared with the third quarter of 2001 was primarily due to higher prices of crude oil and natural gas and higher production volumes of crude oil. During the third quarter of 2002 production from Terra Nova (10,800 bbls/day) and Wenchang (21,900 bbls/day) more than offset lower production of light/medium crude oil from properties in Western Canada. The weighted average royalty rate for light/medium crude oil and NGL decreased in 2002 as a result of the royalty rates of Terra Nova and Wenchang, which are currently low as capital costs are recovered. A 13 percent decline in light/medium crude oil production in Western Canada in the third quarter of 2002 compared with the same period in 2001 was mainly due to higher natural declines and drilling program and tie-in delays. Lloydminster heavy crude oil production was 16 percent higher in the third quarter of 2002 compared with the same quarter in 2001. The higher Lloydminster production resulted primarily from the 2001/2002 drilling program, an active well optimization/workover program and increased production from cold production wells. Natural gas production in the third quarter of 2002 was one percent lower than in the third quarter of 2001. Husky's average realized price for light and medium crude oil and NGL in the third quarter of 2002 was $36.72/bbl, 16 percent higher than that for the same period in 2001. The realized heavy crude oil prices averaged $30.94/bbl, 31 percent higher during the third quarter of 2002 compared to the same period in 2001. The average realized natural gas price of $3.42/mcf was five percent higher during the third quarter of 2002 compared with that for the third quarter in 2001.

The increase in upstream net revenues for the first nine months of 2002 compared with the first nine months of 2001 was due to higher prices for crude oil, higher production volumes of crude oil and to lower natural gas royalties partially offset by lower natural gas and NGL prices, lower natural gas production and higher royalties on heavy oil production.

Netbacks and Operating Costs [1]

Light/Medium Crude Oil Netbacks [2]

Per boe	Three months ended September 30 2002	2001	Nine months ended September 30 2002	2001
Sales revenues	**$ 36.18**	$ 31.57	**$ 31.79**	$ 30.16
Royalties	**5.09**	5.99	**4.37**	5.40
Operating costs	**7.35**	7.55	**7.41**	7.15
Netback	**$ 23.74**	$ 18.03	**$ 20.01**	$ 17.61

[1] *2001 amounts as restated. Refer to note 3 to the consolidated financial statements.*
[2] *Includes associated co-products converted to boe.*

Lloydminster Heavy Crude Oil Netbacks [1]

Per boe	Three months ended September 30 2002	2001	Nine months ended September 30 2002	2001
Sales revenues	**$ 30.82**	$ 23.63	**$ 26.21**	$ 18.25
Royalties	**4.05**	2.29	**2.66**	1.71
Operating costs	**6.14**	7.30	**6.49**	7.84
Netback	**$ 20.63**	$ 14.04	**$ 17.06**	$ 8.70

Natural Gas Netbacks [2]

Per mcfe	Three months ended September 30 2002	2001	Nine months ended September 30 2002	2001
Sales revenues	**$ 3.60**	$ 3.34	**$ 3.61**	$ 6.18
Royalties	**0.65**	0.69	**0.73**	1.51
Operating costs	**0.76**	0.66	**0.69**	0.55
Netback	**$ 2.19**	$ 1.99	**$ 2.19**	$ 4.12

Total Upstream Netbacks [1]

Per boe	Three months ended September 30 2002	2001	Nine months ended September 30 2002	2001
Sales revenues	**$ 30.31**	$ 25.50	**$ 27.02**	$ 29.89
Royalties	**4.45**	4.38	**3.91**	5.86
Operating costs	**6.19**	6.24	**6.08**	5.94
Netback	**$ 19.67**	$ 14.88	**$ 17.03**	$ 18.09

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

Higher average unit operating costs in the first nine months of 2002 compared with the same period in 2001 were primarily attributable to production declines in shallow natural gas and mature waterflood properties but were in line with expectations.

Depletion, Depreciation and Amortization (“DD&A”)

Total upstream DD&A per boe was $7.76 during the third quarter of 2002 compared with $7.30 during the same period in 2001. The higher DD&A per boe in the third quarter of 2002 reflected the proportionately higher capital requirements associated with shallow natural gas, mature waterflood oil properties and the Terra Nova oil field development.

The same factors were responsible for the higher DD&A per boe in the first nine months of 2002 compared with the same period in 2001.

MIDSTREAM

Husky’s midstream operating profit in the third quarter of 2002 decreased 28 percent to $50 million from $69 million in the third quarter of 2001. The decrease in upgrader operating profit was due to lower upgrader throughput and upgrading differential partially offset by lower energy related operating costs and other charges. Production of synthetic crude oil at the upgrader was reduced during the quarter as a result of operational problems. The operational deficiencies have since been remedied and the upgrader is currently operating at or near capacity. Lower midstream operating profit was also attributable to lower pipeline throughput.

Upgrading Operations

		Three months ended September 30		Nine months ended September 30	
		2002	2001	**2002**	2001
Gross margin		**$ 41**	$ 80	**$ 165**	$ 355
Operating costs		**33**	35	**107**	157
Other expenses (recoveries)		**(2)**	4	**(5)**	15
EBITDA		**10**	41	**63**	183
DD&A		**4**	5	**13**	13
Operating profit		**$ 6**	$ 36	**$ 50**	$ 170
Selected operating data:					
Upgrader throughput [1]	*(mbbls/day)*	**53.1**	74.7	**62.8**	74.7
Synthetic crude oil sales	*(mbbls/day)*	**47.3**	66.5	**56.5**	62.8
Upgrading differential	*($/bbl)*	**9.92**	13.18	**9.92**	18.01
Unit margin	*($/bbl)*	**9.25**	12.98	**10.65**	20.68
Unit operating cost [2]	*($/bbl)*	**6.79**	5.12	**6.23**	7.71

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

Upgrading EBITDA Variance Analysis	
Three months ended September 30, 2001	$ 41
Volume	(23)
Differential	(16)
Operating costs - energy	5
Operating costs - non-energy	(3)
Other	6
Three months ended September 30, 2002	**$ 10**
Nine months ended September 30, 2001	$ 183
Volume	(36)
Differential	(155)
Operating costs - energy	(37)
Operating costs - non-energy	13
Other	21
Nine months ended September 30, 2002	**$ 63**

In the first nine months of 2002 midstream operating profit decreased 40 percent to $183 million from $303 million in the first nine months of 2001. The lower operating profit was primarily due to lower upgrading differential and throughput. The lower upgrader throughput resulted from a scheduled plant turnaround in June followed by operational problems requiring further down time in the third quarter. Operating profit from Infrastructure and Marketing operations was comparable in the first nine months of 2002 to the same period in 2001 as the effect of lower pipeline throughput was offset by higher income from marketing activities.

Infrastructure and Marketing

	Three months ended September 30		Nine months ended September 30	
	2002	2001	**2002**	2001
Gross margin - pipeline	**$ 12**	$ 19	**$ 42**	$ 69
- other infrastructure and marketing	**39**	21	**111**	83
	51	40	**153**	152
Other expenses	**2**	2	**6**	6
EBITDA	**49**	38	**147**	146
DD&A	**5**	5	**14**	13
Operating profit	**$ 44**	$ 33	**$ 133**	$ 133
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**436**	498	**451**	544

REFINED PRODUCTS

Husky's total refined products operating profit was $32 million for the third quarter of 2002 compared with $53 million for the third quarter of 2001. Lower margins for asphalt products were due to reduced light to heavy crude oil differentials. Lower diesel sales volume was offset by higher sales volume of gasoline. Diesel was reduced primarily due to lower drilling and service activity in Western Canada.

During the first nine months of 2002, refined products operating profit was $64 million compared with $107 million for the same period in 2001. The lower operating profit in 2002 resulted primarily from the same factors that affected the third quarter of 2002.

Light Oil Products			Three months ended September 30		Nine months ended September 30	
			2002	2001	**2002**	2001
Gross margin	- fuel sales		**$ 28**	$ 25	**$ 64**	$ 63
	- ancillary sales		**7**	8	**19**	21
			35	33	**83**	84
Operating expenses			**9**	8	**23**	21
Other expenses			**4**	5	**9**	12
EBITDA			**22**	20	**51**	51
DD&A			**7**	6	**20**	18
Operating profit			**$ 15**	$ 14	**$ 31**	$ 33
Selected operating data:						
Number of fuel outlets					**573**	584
Fuel sales volume		*(million litres/day)*	**8.2**	8.2	**7.6**	7.7
Refinery throughput		*(mbbls/day)*	**11.0**	8.8	**9.9**	10.1

Asphalt Products		Three months ended September 30		Nine months ended September 30	
		2002	2001	**2002**	2001
Gross margin		**$ 20**	$ 41	**$ 40**	$ 80
Other expenses		**1**	1	**2**	2
EBITDA		**19**	40	**38**	78
DD&A		**2**	1	**5**	4
Operating profit		**$ 17**	$ 39	**$ 33**	$ 74
Selected operating data:					
Sales volume	*(mbbls/day)*	**30.6**	29.9	**23.0**	21.9
Refinery throughput	*(mbbls/day)*	**25.2**	26.1	**23.4**	23.0

CORPORATE

Interest Expense

Net interest expense was $4 million higher in the third quarter of 2002 compared with the same period in 2001 as a result of lower interest capitalization and higher debt levels partially offset by lower interest rates. In the third quarter of 2002 capitalized interest was $6 million lower than in 2001 reflecting the completion of the Terra Nova project. As a result of the same factors, net interest expense in the first nine months of 2002 was slightly higher than for the same period in 2001.

The Company's average interest rate, including the effect of interest rate swaps, during the first nine months of 2002, was 5.46 percent compared with 6.99 percent for the same period in 2001.

Foreign Exchange

The Company recorded foreign exchange losses of $18 million ($7 million related to loss on U.S. denominated long-term debt while the remainder related to settlements and other monetary items) in the first nine months of 2002 compared with $79 million ($70 million related to loss on U.S. denominated long-term debt while the remainder related to settlements and other monetary items) of losses during the same period of 2001, primarily due to the Canadian dollar weakening more from January to September in 2001 compared to the same period in 2002. Effective January 1, 2002, due to a change in Canadian generally accepted accounting principles, foreign exchange gains and losses on long-term monetary items are no longer deferred and amortized but are now reflected in the Statement of Earnings in the period they are determined. Foreign exchange has been adjusted to reflect this change for the comparative periods. The U.S./Canadian exchange rates at September 30, 2002 and December 31, 2001, expressed in Canadian dollars were $1.5858 and $1.5926, respectively and at September 30, 2001 and December 31, 2000 were $1.5790 and $1.5002, respectively.

Income Taxes

Income tax expense was $270 million during the first nine months of 2002 compared with $400 million during the same period in 2001. Lower income tax expense in the first nine months of 2002 was primarily due to lower pre-tax earnings and to the recognition of an adjustment to future income taxes of $27 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. The same period in 2001 included an adjustment to future income taxes of $42 million resulting from a reduction to the Alberta corporate income tax rate.

Sensitivity Analysis

The following table shows the annual effect on net earnings and cash flow of changes in certain key variables. The analysis is based on business conditions and production volumes during the third quarter of 2002. Each separate item in the sensitivity analysis assumes the others are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

Item	*Increase*	*Effect on Pre-tax Cash Flow*		*Effect on Net Earnings*	
		($ millions)	*($/share)[5]*	*($ millions)*	*($/share)[5]*
WTI benchmark crude oil price	*U.S. $1.00/bbl*	103	0.25	65	0.16
NYMEX benchmark natural gas price [1]	*U.S. $0.20/mmbtu*	41	0.10	26	0.06
Light/heavy crude oil differential [2]	*Cdn. $1.00/bbl*	(33)	(0.08)	(20)	(0.05)
Light oil margins	*Cdn. $0.005/litre*	15	0.04	9	0.02
Asphalt margins	*Cdn. $1.00/bbl*	11	0.03	7	0.02
Exchange rate (U.S. $ per Cdn. $) [3]	*U.S. $0.01*	(46)	(0.11)	(29)	(0.07)
Interest rate [4]	*1%*	(10)	(0.02)	(7)	(0.02)

(1) Includes decrease in earnings related to natural gas consumption.
(2) Includes impact of upstream and upgrading operations only.
(3) Assumes no foreign exchange gain or loss. A new accounting standard eliminates the deferral of foreign exchange gains and losses on long-term monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $20 million in net earnings based on September 30, 2002 U.S. $ denominated debt levels.
(4) Interest rate sensitivity based on annual weighted obligations.
(5) Based on September 30, 2002 common shares outstanding of 417.6 million.

Liquidity and Capital Resources

SUMMARY

During the first nine months of 2002, cash available from operating activities amounted to $1,305 million, a decrease of $261 million (17 percent) compared with the same period in 2001. Cash used for investing activities during the first nine months of 2002 amounted to $1,086 million, a decrease of $30 million compared with the same period in 2001. During the first nine months of 2002, cash used for investing activities was comprised of capital expenditures of $1,213 million and investment in other items of $18 million partially offset by a change in non-cash working capital of $63 million and sales of assets of $82 million.

INVESTING ACTIVITIES

Net capital investments during the first nine months of 2002 were financed primarily by cash flow from operating activities, the utilization of credit facilities and through the issue of long-term debt instruments.

Capital Expenditures	Three months ended September 30		Nine months ended September 30	
	2002	2001	**2002**	2001
Upstream				
Exploration				
Western Canada	**$ 47**	$ 44	**$ 206**	$ 179
East Coast Canada	**26**	16	**41**	55
International	**1**	-	**2**	1
	74	60	**249**	235
Development				
Western Canada	**160**	279	**502**	579
East Coast Canada	**143**	27	**320**	82
International	**24**	21	**65**	68
	327	327	**887**	729
	401	387	**1,136**	964
Midstream				
Upgrader	**9**	5	**30**	10
Infrastructure and marketing	**2**	6	**12**	36
	11	11	**42**	46
Refined Products	**9**	7	**22**	17
Corporate	**5**	9	**13**	11
	$ 426	$ 414	**$ 1,213**	$ 1,038

Upstream

During the first nine months of 2002 upstream capital expenditures in Western Canada were $708 million (2001 - $758 million). Exploration and development expenditures in the Lloydminster heavy oil area amounted to $171 million compared with $270 million in the same period of 2001. Exploration and development expenditures in Western Canada conventional areas totalled $537 million during the first nine months of 2002 compared with $488 million in the same period of 2001. During the first nine months of 2002, 276 wells were drilled in the Lloydminster area (2001 - 392), of which 269 were completed and equipped (2001 - 360). In Western Canada conventional areas 607 wells were drilled (2001 - 510), of which 561 were completed and equipped (2001 - 456). Exploration spending in Western Canada during the first nine months of 2002 was $206 million, or 29 percent of total Western Canada upstream capital expenditures, which is generally within a consistent range for the Company. Exploration focus remained on plays extending from the Alberta foothills and deep basin through to northeast British Columbia and northwest Alberta.

During the first nine months of 2002, $361 million was spent offshore the east coast of Canada comprising exploration ($26 million) at Trepassey and Gros Morne and development projects at White Rose ($316 million) and Terra Nova ($19 million).

During the first nine months of 2002, $67 million was spent in international areas primarily on the Wenchang oil field development project ($65 million) and exploration program ($2 million) offshore southern China.

Wells Drilled [1]									
		Three months ended September 30				Nine months ended September 30			
		2002		2001		**2002**		2001	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Western Canada									
Exploration	Oil	**6**	**6**	8	8	**18**	**17**	70	68
	Gas	**17**	**16**	14	11	**124**	**117**	92	84
	Dry	**2**	**2**	3	2	**12**	**12**	32	30
		25	**24**	25	21	**154**	**146**	194	182
Development	Oil	**197**	**190**	214	195	**369**	**346**	456	426
	Gas	**79**	**67**	65	57	**319**	**293**	198	168
	Dry	**16**	**14**	23	23	**41**	**38**	54	52
		292	**271**	302	275	**729**	**677**	708	646
		317	**295**	327	296	**883**	**823**	902	828

[1] *Excludes stratigraphic test wells.*

Midstream

Midstream capital expenditures for property, plant and equipment during the first nine months of 2002 were $42 million including $30 million for the Husky Lloydminster Upgrader (2001 - $10 million) and $12 million for pipeline and cogeneration projects (2001 - $36 million).

Refined Products

Refined products capital expenditures amounted to $22 million during the first nine months of 2002, including $11 million for marketing outlet improvements, $3 million on asphalt distribution systems, $6 million for various improvements at the Lloydminster asphalt refinery and $2 million at the Prince George refinery compared with total refined products capital expenditures of $17 million in the first nine months of 2001.

FINANCING ACTIVITIES

Total debt, net of cash and cash equivalents of $140 million, was $2,277 million at September 30, 2002 compared with $2,192 million at December 31, 2001.

At September 30, 2002, $50 million of net trade receivables had been sold under a Receivables Sale Agreement compared with $200 million at December 31, 2001.

Effective June 14, 2002, the Company issued U.S. $400 million of 6.25 percent notes under a U.S. $1 billion base shelf prospectus dated June 6, 2002. See note 6 to the consolidated financial statements.

The Company believes its internally generated liquidity, together with access to external credit resources, will be sufficient to satisfy existing commitments and plans, and also to provide adequate flexibility to take advantage of potential business opportunities.

Common Share Information

(thousands of shares, except per share amounts)		Nine months ended September 30 2002	Year ended December 31 2001
Share price [1]	High	**$ 17.98**	$ 20.95
	Low	**$ 14.00**	$ 13.10
	Close at end of period	**$ 16.70**	$ 16.47
Average daily trading volume		**509**	625
Weighted average number of common shares outstanding			
	Basic	**417,317**	416,100
	Diluted	**419,255**	418,640
Number of common shares outstanding at end of period		**417,584**	416,878

[1] *Trading in the common shares of Husky Energy Inc. ("HSE") commenced on The Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.*

Certain statements contained herein, including statements which may contain words such as "could", "expect", "believe", "will" and similar expressions and statements relating to matters that are not historical facts are forward-looking statements. Actual future results may differ materially. Husky's annual report to shareholders and other documents filed with securities regulatory authorities describe the risks, uncertainties and other factors, such as changes in business plans and estimated amounts and timing of capital expenditures and changes in estimates of future production, that could influence actual results.

CONSOLIDATED BALANCE SHEETS

(millions of dollars)	**September 30 2002**	December 31 2001
	(unaudited)	*(audited)*
Assets		
Current assets		
Cash and cash equivalents	**$ 140**	$ -
Accounts receivable	**732**	376
Inventories	**241**	226
Prepaid expenses	**32**	24
	1,145	626
Property, plant and equipment - (full cost accounting)	**14,017**	13,078
Less accumulated depletion, depreciation and amortization	**4,863**	4,363
	9,154	8,715
Other assets (*note 3*)	**49**	29
	$ 10,348	$ 9,370
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans *(note 5)*	**$ -**	$ 100
Accounts payable and accrued liabilities	**912**	821
Long-term debt due within one year *(note 6)*	**185**	144
	1,097	1,065
Long-term debt *(note 6)*	**2,232**	1,948
Site restoration provision	**242**	212
Future income taxes *(note 8)*	**1,860**	1,659
Shareholders' equity		
Capital securities and accrued return	**357**	367
Common shares *(note 7)*	**3,402**	3,397
Retained earnings	**1,158**	722
	4,917	4,486
	$ 10,348	$ 9,370
Commitments *(note 9)*		
Common shares outstanding *(millions) (note 7)*	**417.6**	416.9

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 amounts as restated.

CONSOLIDATED STATEMENTS OF EARNINGS

(unaudited)

(millions of dollars, except per share amounts)	Three months ended September 30 **2002**	Three months ended September 30 2001	Nine months ended September 30 **2002**	Nine months ended September 30 2001
Sales and operating revenues, net of royalties (*note 3*)	**$ 1,669**	$ 1,470	**$ 4,687**	$ 4,981
Costs and expenses				
Cost of sales and operating expenses (*note 3*)	**1,000**	937	**3,008**	3,152
Selling and administration expenses	**29**	23	**67**	63
Depletion, depreciation and amortization	**239**	205	**683**	593
Interest - net *(note 6)*	**28**	24	**79**	78
Foreign exchange *(note 3)*	**75**	56	**18**	79
Other - net	**1**	3	**-**	7
	1,372	1,248	**3,855**	3,972
Earnings before income taxes	**297**	222	**832**	1,009
Income taxes *(note 8)*				
Current	**26**	5	**60**	15
Future	**98**	99	**210**	385
	124	104	**270**	400
Net earnings	**$ 173**	$ 118	**$ 562**	$ 609
Earnings per share *(note 11)*				
Basic	**$ 0.38**	$ 0.25	**$ 1.31**	$ 1.40
Diluted	**$ 0.38**	$ 0.24	**$ 1.31**	$ 1.39
Weighted average number of common shares outstanding *(millions) (note 11)*				
Basic	**417.5**	416.0	**417.3**	415.9
Diluted	**419.1**	419.2	**419.3**	418.4

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(unaudited)

(millions of dollars)	Three months ended September 30 **2002**	Three months ended September 30 2001	Nine months ended September 30 **2002**	Nine months ended September 30 2001
Beginning of period	**$ 1,037**	$ 657	**$ 722**	$ 304
Net earnings	**173**	118	**562**	609
Dividends on common shares	**(38)**	(37)	**(113)**	(112)
Return on capital securities (net of related taxes and foreign exchange)	**(14)**	(14)	**(13)**	(26)
Foreign exchange (retroactive adjustment)	**-**	-	**-**	(51)
End of period	**$ 1,158**	$ 724	**$ 1,158**	$ 724

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 amounts as restated.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

(millions of dollars, except per share amounts)	Three months ended September 30 **2002**	Three months ended September 30 2001	Nine months ended September 30 **2002**	Nine months ended September 30 2001
Operating activities				
Net earnings	**$ 173**	$ 118	**$ 562**	$ 609
Items not affecting cash				
Depletion, depreciation and amortization	**239**	205	**683**	593
Future income taxes	**98**	99	**210**	385
Foreign exchange - non cash *(note 3)*	**77**	55	**7**	70
Other	**3**	1	**(1)**	2
Cash flow from operations	**590**	478	**1,461**	1,659
Change in non-cash working capital *(note 10)*	**(140)**	(15)	**(156)**	(93)
	450	463	**1,305**	1,566
Financing activities				
Bank operating loans financing - net	**-**	4	**(100)**	(23)
Long-term debt issue	**-**	-	**972**	-
Long-term debt repayment	**(9)**	(29)	**(655)**	(332)
Return on capital securities payment	**(15)**	(15)	**(31)**	(30)
Debt issue costs	**(2)**	-	**(9)**	-
Deferred credits	**-**	(3)	**-**	(3)
Proceeds from exercise of stock options	**1**	3	**5**	5
Dividends on common shares	**(38)**	(37)	**(113)**	(112)
Change in non-cash working capital *(note 10)*	**(140)**	43	**(148)**	45
	(203)	(34)	**(79)**	(450)
Available for investing	**247**	429	**1,226**	1,116
Investing activities				
Capital expenditures	**(426)**	(414)	**(1,213)**	(1,038)
Corporate acquisitions	**-**	(91)	**-**	(125)
Asset sales	**65**	27	**82**	63
Other	**(8)**	1	**(18)**	4
Change in non-cash working capital *(note 10)*	**90**	48	**63**	(20)
	(279)	(429)	**(1,086)**	(1,116)
Increase in cash and cash equivalents	**(32)**	-	**140**	-
Cash and cash equivalents at beginning of period	**172**	-	**-**	-
Cash and cash equivalents at end of period	**$ 140**	$ -	**$ 140**	$ -
Cash flow from operations per share *(note 11)*				
Basic	**$ 1.39**	$ 1.13	**$ 3.44**	$ 3.93
Diluted	**$ 1.39**	$ 1.12	**$ 3.43**	$ 3.91

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 amounts as restated.

Notes to the Consolidated Financial Statements

Nine months ended September 30, 2002 (*unaudited*)

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

Note 1 Segmented Financial Information

	Upstream		Midstream: Upgrading		Midstream: Infrastructure and Marketing		Refined Products		Corporate and Eliminations [4]		Total	
	2002	2001	**2002**	2001	**2002**	2001	**2002**	2001	**2002**	2001	**2002**	2001
Three months ended September 30 [1]												
Sales and operating revenues, net of royalties	**$ 738**	$ 549	**$ 192**	$ 255	**$ 953**	$ 796	**$ 431**	$ 429	**$ (645)**	$ (559)	**$ 1,669**	$ 1,470
Costs and expenses [2]	**173**	163	**182**	214	**904**	758	**390**	369	**(544)**	(485)	**1,105**	1,019
EBITDA	**565**	386	**10**	41	**49**	38	**41**	60	**(101)**	(74)	**564**	451
Depletion, depreciation and amortization	**218**	185	**4**	5	**5**	5	**9**	7	**3**	3	**239**	205
Operating profit	**$ 347**	$ 201	**$ 6**	$ 36	**$ 44**	$ 33	**$ 32**	$ 53	**(104)**	(77)	**325**	246
Interest - net									**28**	24	**28**	24
Earnings (loss) before income taxes									**(132)**	(101)	**297**	222
Current income taxes									**26**	5	**26**	5
Future income taxes									**98**	99	**98**	99
Net earnings (loss)									**$ (256)**	$ (205)	**$ 173**	$ 118
Capital expenditures - Three months ended September 30	**$ 401**	$ 387	**$ 9**	$ 5	**$ 2**	$ 6	**$ 9**	$ 7	**$ 5**	$ 9	**$ 426**	$ 414
Nine months ended September 30 [1]												
Sales and operating revenues, net of royalties	**$ 1,884**	$ 1,798	**$ 608**	$ 739	**$ 2,863**	$ 3,227	**$ 984**	$ 1,075	**$ (1,652)**	$ (1,858)	**$ 4,687**	$ 4,981
Costs and expenses [2]	**496**	447	**545**	556	**2,716**	3,081	**895**	946	**(1,559)**	(1,729)	**3,093**	3,301
EBITDA	**1,388**	1,351	**63**	183	**147**	146	**89**	129	**(93)**	(129)	**1,594**	1,680
Depletion, depreciation and amortization	**620**	535	**13**	13	**14**	13	**25**	22	**11**	10	**683**	593
Operating profit	**$ 768**	$ 816	**$ 50**	$ 170	**$ 133**	$ 133	**$ 64**	$ 107	**(104)**	(139)	**911**	1,087
Interest - net									**79**	78	**79**	78
Earnings (loss) before income taxes									**(183)**	(217)	**832**	1,009
Current income taxes									**60**	15	**60**	15
Future income taxes									**210**	385	**210**	385
Net earnings (loss)									**$ (453)**	$ (617)	**$ 562**	$ 609
Capital expenditures - Nine months ended September 30	**$ 1,136**	$ 964	**$ 30**	$ 10	**$ 12**	$ 36	**$ 22**	$ 17	**$ 13**	$ 11	**$ 1,213**	$ 1,038
Identifiable assets - As at September 30 [3]	**$ 7,752**	$ 7,172	**$ 622**	$ 572	**$ 408**	$ 393	**$ 323**	$ 319	**$ 1,243**	$ 806	**$ 10,348**	$ 9,262

[1] 2001 amounts as restated.
[2] Costs and expenses include cost of sales and operating expenses, selling and administration expenses, foreign exchange and other - net.
[3] Identifiable assets by segment are the total assets specifically attributable to those operations at September 30. Corporate accounts include accounts receivable, inventories, prepaid expenses, other assets and corporate assets.
[4] 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, 2001, 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, 2001. Certain information provided for prior periods has been reclassified to conform with current presentation.

Cash and Cash Equivalents

Cash and cash equivalents consists of cash on hand and deposits with a maturity of less than three months.

Note 3 Accounting Changes

Effective January 1, 2002, the Company retroactively adopted the revised recommendations of the Canadian Institute of Chartered Accountants on Foreign Currency Translation. The new recommendations eliminated the deferral and amortization of foreign exchange gains and losses on long-term monetary items. This change resulted in a reduction of retained earnings at January 1, 2001 of $51 million. This change also resulted in a reduction to other assets of $133 million, a reduction to the future income tax liability of $36 million and an increase to capital securities of $17 million as at December 31, 2001. Net earnings for the nine months ended September 30, 2001 were reduced by $43 million and retained earnings were reduced by $56 million, which included an adjustment to the accrued return on the capital securities.

In 2001 and previously, the Company presented certain crown charges as a component of operating expenses. These charges have been reclassified as royalties for 2002 and for all comparative periods presented in these financial statements. There is no impact on the earnings or cash flow of the Company as a result of this change.

Note 4 Financial Instruments and Risk Management

Commodity Marketing Activities

In September 2002 the Company entered into variable price physical forward sales with respect to crude oil of 20,000 bbls/day for October and November 2002. The physical sales were hedged by a number of financial transactions in which Husky pays the same variable pricing but receives fixed pricing. The average fixed price Husky receives under these financial transactions for October production is U.S. $30.513/bbl and the average fixed price for the November production is U.S. $30.178/bbl.

Interest Rate Risk

The Company has entered into interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms:

Debt	Amount (millions)	Swap Maturity	Swap Rate (%)
6.875% notes	U.S. $ 35	November 15, 2003	U.S. LIBOR - 13 bps
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.125% notes	U.S. $150	November 15, 2006	U.S. LIBOR + 235 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps
6.25% senior notes	U.S. $150	June 15, 2012	U.S. LIBOR + 88 bps

During the first nine months of 2002, the Company recognized a gain of $20 million from interest rate management activities (2001 - gain of $1 million).

Sale of Accounts Receivable

The Company has an agreement to sell net trade receivables of up to $200 million on a continual basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, to be paid on an ongoing basis. The average effective rate during the first nine months of 2002 was 2.73 percent (first nine months 2001 - 5.28 percent). The Company has potential exposure to an immaterial amount of credit loss under this agreement. At September 30, 2002, $50 million of net trade receivables had been sold under the agreement.

Note 5 Bank Operating Loans

At September 30, 2002 the Company did not have any outstanding bank operating loans compared with $100 million at December 31, 2001. The Company has $195 million in short-term borrowing facilities available to it. The interest rates applicable to these facilities vary and are based on Canadian prime, Bankers' Acceptance, money market rates or U.S. dollar equivalents.

Note 6 Long-term Debt

			Maturity	**Sept. 30 2002**	Dec. 31 2001
Long-term debt					
Revolving syndicated credit facility	*-2001*	*U.S. $116*	2006	**$ -**	$ 185
6.25% notes	*-2002*	*U.S. $400*	2012	**634**	-
6.875% notes	*-2002 & 2001*	*U.S. $150*	2003	**238**	239
7.125% notes	*-2002 & 2001*	*U.S. $150*	2006	**238**	239
7.55% debentures	*-2002 & 2001*	*U.S. $200*	2016	**317**	318
8.45% senior secured bonds	*-2002*	*U.S. $162;*			
	2001	*U.S. $173*	2003-12	**258**	276
Private placement notes	*-2002*	*U.S. $83;*			
	2001	*U.S. $85*	2002-5	**132**	135
Medium-term notes			2003-9	**600**	700
Total long-term debt				**2,417**	2,092
Amount due within one year				**(185)**	(144)
				$ 2,232	$ 1,948

At September 30, 2002, the Company did not have any borrowings under the Company's $940 million syndicated credit facility. Interest rates under the 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.

Interest - net consists of:

	Three months ended September 30		Nine months ended September 30	
	2002	2001	**2002**	2001
Long-term debt	**$ 35**	$ 36	**$ 95**	$ 113
Short-term debt	**-**	2	**2**	4
	35	38	**97**	117
Amount capitalized	**(7)**	(13)	**(17)**	(37)
	28	25	**80**	80
Interest income	**-**	(1)	**(1)**	(2)
	$ 28	$ 24	**$ 79**	$ 78

Note 7 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 during 2002 were as follows:

	Three months ended September 30		Nine months ended September 30	
	Number of Common Shares	Amount	Number of Common Shares	Amount
Balance at beginning of period	417,471,558	$ 3,401	416,878,093	$ 3,397
Exercised for cash - options and warrants	112,826	1	706,291	5
Balance at September 30, 2002	**417,584,384**	**$ 3,402**	**417,584,384**	**$ 3,402**

As the Company follows the intrinsic value method of accounting for stock-based compensation, no compensation cost has been recognized for its fixed stock option plan. Had compensation cost for the Company's stock option plan been determined based on the fair value at the grant dates for awards under the plan after January 1, 2002, the Company's pro-forma net earnings and earnings per share would have been the same as those reported.

The weighted average fair market value of options granted in the first nine months of 2002 was $5.99 per option. The fair value of each option granted was estimated on the date of grant using the Modified Black-Scholes option-pricing model with the following assumptions:

Modified Black-Scholes Assumptions	
Risk-free interest rate	3.5%
Volatility	45%
Expected life	Five years
Expected annual dividend per share	$0.36

A summary of the status of the Company's fixed stock option plan and changes during 2002 is presented below:

Fixed Options	Three months ended September 30, 2002		Nine months ended September 30, 2002	
	Number of Shares *(thousands)*	Weighted Average Exercise Prices	Number of Shares *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	8,309	$13.87	8,602	$13.78
Granted	-	-	329	$16.32
Exercised	(113)	$13.57	(356)	$13.58
Forfeited	(127)	$14.72	(506)	$14.34
Outstanding, September 30	**8,069**	**$13.86**	**8,069**	**$13.86**
Options exercisable at September 30			5,084	$13.72

At September 30, 2002, the options outstanding had exercise prices ranging from $11.16 to $19.76 with a weighted average contractual life of 3.0 years.

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

Note 8 Income Taxes

Income tax expense in the first nine months of 2002 included an adjustment to future income taxes of $27 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. The same period in 2001 included an adjustment to future income taxes of $42 million resulting from a reduction to the Alberta corporate income tax rate.

Note 9 Commitments

The Company has awarded various contracts for the construction of the floating production, storage and offloading vessel and several other components of the White Rose development project with expected completion dates in 2005. The Company's share of the total value of contractual obligations at September 30, 2002 was $1.0 billion. As at September 30, 2002, the Company had spent $201 million on these contracts.

Note 10 Cash Flows

	Three months ended September 30		Nine months ended September 30	
	2002	2001	**2002**	2001
a) Changes in non-cash working capital were as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ (276)**	$ 143	**$ (314)**	$ 249
Inventories	**3**	5	**(15)**	(43)
Prepaid expenses	**(10)**	(1)	**(8)**	(2)
Accounts payable and accrued liabilities	**93**	(71)	**96**	(272)
Change in non-cash working capital	**(190)**	76	**(241)**	(68)
Relating to:				
Financing activities	**(140)**	43	**(148)**	45
Investing activities	**90**	48	**63**	(20)
Operating activities	**$ (140)**	$ (15)	**$ (156)**	$ (93)
b) Other cash flow information:				
Cash taxes paid	**$ 6**	$ -	**$ 20**	$ 13
Cash interest paid	**$ 24**	$ 33	**$ 94**	$ 106

Note 11 Net Earnings and Cash Flow from Operations Per Common Share

	Three months ended September 30		Nine months ended September 30	
	2002	2001	**2002**	2001
Cash flow from operations	**$ 590**	$ 478	**$ 1,461**	$1,659
Return on capital securities	**(9)**	(8)	**(25)**	(24)
Cash flow from operations available to common shareholders	**$ 581**	$ 470	**$ 1,436**	$1,635
Net earnings	**$ 173**	$ 118	**$ 562**	$ 609
Return on capital securities (net of related taxes and foreign exchange)	**(14)**	(16)	**(14)**	(27)
Net earnings available to common shareholders	**$ 159**	$ 102	**$ 548**	$ 582
Weighted average number of common shares outstanding - Basic *(millions)*	**417.5**	416.0	**417.3**	415.9
Effect of dilutive stock options and warrants	**1.6**	3.2	**2.0**	2.5
Weighted average number of common shares outstanding - Diluted *(millions)*	**419.1**	419.2	**419.3**	418.4
Cash flow from operations				
Per share - Basic	**$ 1.39**	$ 1.13	**$ 3.44**	$ 3.93
- Diluted	**$ 1.39**	$ 1.12	**$ 3.43**	$ 3.91
Net earnings				
Per share - Basic	**$ 0.38**	$ 0.25	**$ 1.31**	$ 1.40
- Diluted	**$ 0.38**	$ 0.24	**$ 1.31**	$ 1.39

Terms and Abbreviations

bbls	barrels
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
mcfe	thousand cubic feet of gas equivalent
GJ	gigajoule
mmbtu	million British Thermal Units
mmlt	million long tons
NGL	natural gas liquids
hectare	1 hectare is equal to 2.47 acres
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
Cold Production	A production process that achieves high recovery rates through the use of progressive cavity pumps, which simultaneously produce heavy oil and sand from unconsolidated formations.
EBITDA	Earnings from operations before interest, income taxes and depletion, depreciation and amortization
Equity	Capital securities and accrued return, shares and retained earnings
Free Cash Flow	Cash flow from operations less capitalized administration and capitalized interest
Operating Profit	Earnings from operations before interest and taxes
Total Debt	Long-term debt including current portion and short-term debt

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 Wednesday, October 30, 2002 at 4:15 p.m. Eastern time to discuss Husky's third quarter results. To participate, please dial 1 (888) 793-1753 beginning at 4:05 p.m. Eastern time. Media are invited to participate in the call on a listen-only basis by dialing 1 (888) 793-1716 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 20953120. The PostView will be available until Wednesday November 13, 2002.

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