U.S. SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2002. Commission file number 1-4307

Husky Energy Inc.

(Exact name of Registrant as specified in its charter)

Canada	**1311**	**Not applicable.**
(Province or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

770 – 8 Avenue S.W.
PO Box 6525 Station D
Calgary, Alberta, Canada T2P 3G7
(403) 298-6111

(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue, New York, New York 10011
(212) 894-8400

(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

None

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

6.25% Notes due 2012

For annual reports, indicate by check mark the information filed with this Form:

☒ Annual information form ☒ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

The Registrant had 417,873,601 Common Shares outstanding at December 31, 2002

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

☐ Yes ☒ No

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to filing requirements for the past 90 days.

☒ Yes ☐ No

PRIOR FILINGS MODIFIED AND SUPERSEDED

The Registrant's Annual Report on Form 40-F for the year ended December 31, 2002, at the time of filing with the Securities and Exchange Commission, modifies and supersedes all prior documents filed pursuant to Sections 13, 14 and 15(d) of the Exchange Act for purposes of any offers or sales of any securities after the date of such filing pursuant to any Registration Statement under the Securities Act of 1933 which incorporates by reference such Annual Report, including without limitation the Registrant's Registration Statement on Form F-9, No. 333-89714.

CONSOLIDATED AUDITED ANNUAL FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION AND ANALYSIS

A. Audited Annual Financial Statements

For consolidated audited financial statements, including the report of independent chartered accountants with respect thereto, see pages 60 through 86 of the Registrant's 2002 Annual Report attached hereto and included herein. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 16 of the Notes to the Consolidated Financial Statements on pages 80 through 86 of such 2002 Annual Report.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 33 through 58 of the Registrant's 2002 Annual Report attached hereto and included herein.

For the purposes of this Annual Report on Form 40-F, only pages 32 through 86 of the Registrants' 2002 Annual Report referred to above shall be deemed filed, and the balance of such 2002 Annual Report, except as it may be otherwise specifically incorporated by reference in the Registrants' Annual Information Form, shall be deemed not filed with the Securities and Exchange Commission as part of this Annual Report on Form 40-F under the Exchange Act.

CONTROLS AND PROCEDURES

See Exhibit No. 4, Management's Discussion and Analysis of the Registrant for the year ended December 31, 2002, to this Annual Report on Form 40-F.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when required to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the

securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

A Form F-X signed by the Registrant and its agent for service of process was filed with the Commission together with the Registrant's Annual Report on Form 40-F for the fiscal year ended December 31, 2001.

SIGNATURE

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

Husky Energy Inc.

March 26, 2003

By: /s/ Neil D. McGee

Name: Neil D. McGee
Title: Vice President & Chief Financial Officer

By: /s/ James D. Girgulis

Name: James D. Girgulis
Title: Vice President, Legal & Corporate Secretary

CERTIFICATIONS

I, John C.S. Lau, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 26, 2003

/s/ John C.S. Lau

John C.S. Lau
President & Chief Executive Officer

I, Neil D. McGee, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 26, 2003

/s/ Neil D. McGee

Neil D. McGee
Vice President & Chief Financial Officer

Form 40-F Table of Contents

Exhibit No.	Document
1.	Renewal Annual Information Form of the Registrant for the fiscal year ended December 31, 2002.
2.	Consolidated Financial Statements of the Registrant for the year ended December 31, 2002, including a reconciliation to United States generally accepted accounting principles.
3.	Management's Discussion and Analysis of the Registrant for the year ended December 31, 2002.
4.	Reconciliation of reserves information set forth on page 91 of the Registrant's 2002 Annual Report.[1]
5.	Wells drilled information set forth on page 48 of the Registrant's 2002 Annual Report.[2]
6.	Consent of KPMG LLP, independent accountants.
7.	Consent of McDaniel and Associates Consultants Ltd., independent engineers.
8.	Certificate of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
9.	Certificate of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

1 Need be included only to the extent such information is incorporated by reference into the AIF.

2 Need be included only to the extent such information is incorporated by reference into the AIF.

Exhibit 1

HUSKY ENERGY INC.

RENEWAL ANNUAL INFORMATION FORM

For the Year Ended December 31, 2002

March 26, 2003

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ABBREVIATIONS

As used in this Annual Information Form, the following terms have the meanings indicated:

API	- American Petroleum Institute
bbl	- barrel
bbls	- barrels
mbbls	- thousand barrels
mmbbls	- million barrels
mcf	- thousand cubic feet
mmcf	- million cubic feet
bcf	- billion cubic feet
mcfge	- thousand cubic feet of gas equivalent
mlt	- thousand long tons
NGL	- natural gas liquids
boe	- barrels of oil equivalent
boe/day	- barrels of oil equivalent per day
bbls/day	- barrels per day
mbbls/day	- thousand barrels per day
mmcf/day	- million cubic feet per day
lt/day	- long tons per day
mlt/day	- thousand long tons per day
MW	- megawatts

Unless otherwise noted, gross reserves or gross production are reserves or production attributable to Husky's interest prior to deduction of royalties; net reserves or net production are reserves or production net of such royalties. Gross or net production reported refers to sales volume, unless otherwise indicated. Natural gas volumes are converted to a boe basis using the ratio of six mcf of natural gas to one bbl of oil and natural gas liquids. Natural gas volumes are stated at the official temperature and pressure basis of the area in which the reserves are located.

HUSKY ENERGY INC.

Husky Energy Inc. ("Husky Energy") was incorporated under the *Business Corporations Act* (Alberta) on June 21, 2000. From the date of its incorporation until August 25, 2000, Husky Energy did not carry on any business. On August 25, 2000, Husky Energy was a party to a plan of arrangement under the *Business Corporations Act* (Alberta) (the "Arrangement") pursuant to which Husky Oil Limited ("Husky Oil"), Husky Oil Operations Limited (a subsidiary of Husky Oil) and Renaissance Energy Ltd. ("Renaissance") were amalgamated under the *Business Corporations Act* (Alberta) and continued as one corporation under the name "Husky Oil Operations Limited" ("HOOL") and the securityholders of Renaissance and Husky Oil exchanged their securities for securities of Husky Energy. Under the Arrangement, Husky Energy acquired 100% of the common shares of HOOL.

Husky Energy has its registered office and its head and principal office at 707 - 8th Avenue S.W., P.O. Box 6525, Station D, Calgary, Alberta, T2P 3G7.

In this Annual Information Form the term "Husky" or "the Company" means Husky Energy and its subsidiaries and partnership interests on a consolidated basis including information with respect to predecessor corporations.

SUBSIDIARIES OF HUSKY

The principal subsidiaries of Husky and place of incorporation, continuance or place of organization, as the case may be, are as follows. All of the following companies are directly or indirectly 100% owned.

Name	Jurisdiction
Subsidiaries of Husky Energy Inc.	
Husky Oil Operations Limited	Nova Scotia
Subsidiaries of Husky Oil Operations Limited	
Husky Oil Limited	Canada
Husky Energy Marketing Inc.	Alberta
Husky (U.S.A.) Inc.	Delaware
HOI Resources Co.	Nova Scotia
Husky Energy International Sulphur Corporation	Alberta
147212 Canada Ltd.	Canada
Subsidiaries of Husky (U.S.A.) Inc.	
Husky Gas Marketing Inc.	Delaware
Subsidiaries of HOI Resources Co.	
Husky Energy International Corporation	Alberta

Name	Jurisdiction
Subsidiaries of Husky Energy International Corporation	
Husky Oil China Ltd.	Alberta
Husky Oil (Madura) Ltd.	Alberta
Husky Oil Overseas Ltd.	Alberta

HISTORY AND DEVELOPMENT OF HUSKY

The following describes the development of Husky's business over the last three years.

Effective January 1, 2000, Husky exchanged interests in the Terra Nova oil field and White Rose oil field, located in the Jeanne d'Arc basin off the east coast of Newfoundland, for producing properties in Alberta. Under the terms of the agreement Husky acquired working interests in the Valhalla and Wapiti fields which produce crude oil, natural gas liquids and natural gas. The properties are located in West Central Alberta near Grande Prairie. In exchange Husky gave up a 4.99% interest in the Terra Nova field and 10% of the White Rose field. Husky retained 12.51% of Terra Nova and 72.5% of White Rose. Terra Nova commenced production in January 2002 and the White Rose development project was sanctioned in March 2002.

In May 2000, Husky redeemed U.S. $71 million (Cdn. $104 million as at that date) of its 8.45% Senior Secured Bonds as a result of the reduction of the ownership interest in the Terra Nova oil field. The amount of the redemption coincided with the reduction of Husky's interest from 17.5% to 12.51%.

On June 18, 2000, Husky Oil and Renaissance entered into an agreement that contemplated the merger of Renaissance and Husky Oil pursuant to a plan of arrangement under the provisions of the *Business Corporations Act* (Alberta). Renaissance was a publicly listed senior oil and gas exploration and development company conducting operations primarily in Western Canada. Pursuant to the arrangement, shareholders of Renaissance received one common share of Husky and a cash payment of $2.50 per share as well as the right to participate in a buyback of approximately 18% of the common shares of Renaissance by shareholders of Husky Oil. Former shareholders of Husky Oil received approximately 71.7% of the common shares of Husky and former shareholders of Renaissance received approximately 28.3% of the common shares of Husky. Pursuant to the arrangement, Husky Oil, Renaissance and Husky Oil Operations Limited amalgamated to form HOOL. Also pursuant to the arrangement, Husky disposed of certain non-energy related assets to the former shareholders of Husky Oil. The arrangement was completed on August 25, 2000 and Husky's common shares commenced trading on the Toronto Stock Exchange on August 28, 2000.

In July 2000, Husky Oil repaid U.S. $116 million of its 10.6% senior notes to retire the issue. The repayment was funded under Husky Oil's syndicated credit facility.

On October 13, 2000, Husky Oil China Ltd., a subsidiary of Husky signed a petroleum contract with the China National Offshore Oil Corporation ("CNOOC") to develop two high quality oilfields in the South China Sea. The Wenchang 13-1 and 13-2 fields are located in the western Pearl River Mouth Basin, approximately 300 kilometres south of Hong Kong and 136 kilometres east of Hainan Island. Husky holds a 40% interest in these fields. At December 31, 2002, Husky's share of gross proved reserves was 30.1 mmbbls of light crude oil.

In December 2000, Husky expanded its acreage position offshore Newfoundland with the acquisition of a 100% working interest in the Grand Bank (339 square kilometres) and Gros Morne (201 square kilometres) Exploration Licenses south and west of the White Rose

Significant Discovery Area. The Grand Bank and Gros Morne Exploration Licenses form a large contiguous exploration area with the Trepassey (100% working interest) and North Amethyst (70% working interest) blocks and the White Rose Significant Discovery Area.

In December 2000, Husky acquired two Exploration Licenses comprising 1,087,000 acres in the South Whale Basin, a new exploration area on the southern Grand Banks. The regional setting of the South Whale Basin is similar to that of the proven hydrocarbon-bearing Jeanne d'Arc and Sable Basins.

In late 2000, Husky acquired a 50% working interest in an adjacent lease to the north of its Kearl lease in east central Alberta where Husky held a 51% working interest.

In January 2001, Husky amended and restated its Canadian syndicated $1 billion bank facility.

On July 4, 2001, Husky acquired all of the outstanding Class A Common Shares and Class B Common Shares of Avid Oil & Gas Ltd. ("Avid"), which it did not already own, pursuant to an offer to purchase dated March 23, 2001. The acquisition of Avid was completed pursuant to a Pre-Acquisition Agreement which provided for the acquisition of the Class A Common Shares of Avid at a price of $5.85 per share and the Class B Common Shares of Avid at a price of $10.00 per share for a total consideration of approximately $82.6 million. Husky had previously owned approximately 38% of the Class A Common Shares of Avid as a result of the acquisition of Renaissance in August 2000.

By December 2001 the White Rose project had received government sanction from the Canada-Newfoundland Offshore Petroleum Board and the Provincial and Federal governments. In March 2002, Husky and its co-venturer announced that they had decided to proceed with the development of the White Rose oil field.

The Terra Nova development project commenced production in January 2002. This project was the first Grand Banks field to be developed with a floating production, storage and offloading system. The first well in the Far East block was successfully drilled in 2001. Husky's share of production from Terra Nova averaged 13,200 barrels of oil per day in 2002.

In June 2002, Husky issued U.S. $400 million of 6.25% senior notes due June 15, 2012. The notes were sold at a price of 99.545% per note to yield 6.312%. The notes were issued under a U.S. $1 billion base shelf prospectus dated June 6, 2002. The proceeds were used to repay existing bank indebtedness and for general corporate purposes.

On July 7, 2002, the Wenchang oil fields, 13-1 and 13-2, produced first oil. The oil fields produce light crude oil similar to the benchmark Minas blend from two production platforms into a floating production, storage and offloading vessel stationed between the two fields.

In September 2002, Husky signed contracts for two exploration leases in the South China Sea. The 23/15 lease comprises 1,327 square kilometres and the 23/20 lease comprises 1,543 square kilometres. The contracts require one well to be drilled on each lease within three years.

In November 2002, Husky announced a significant discovery of natural gas at Shackleton, Saskatchewan. The Company announced that development of the Shackleton area could add 250 bcf to proved reserves within two to three years. Husky held more than 400 sections of land comprising 300,000 acres in this area at year-end.

In December 2002, Husky signed a contract for the 40/30 exploration block in the South China Sea. The block comprises approximately 6,704 square kilometres and the contract requires one well to be drilled within three years.

In December 2002, Husky swapped, with its co-venturer, its working interest in the mining portion of its Kearl oil sands property for its co-venturer's interest in the in-situ portion of the property. As a result Husky now holds 100% working interest in 16,000 acres of lands with in-situ potential.

BUSINESS OF HUSKY

Husky is a publicly held integrated energy and energy related company headquartered in Calgary, Alberta. Husky's operations include the exploration for and development of crude oil and natural gas properties, as well as the production, purchase, transportation, storage and marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke, and the upgrading and refining of crude oil and marketing of refined petroleum products, including gasoline, diesel, alternative fuels and asphalt products.

Upstream Business

Husky's portfolio of assets includes properties that produce light, medium and heavy gravity crude oil, NGL, natural gas and sulphur. As operator of the majority of its properties Husky exercises a high degree of control in its upstream operations. Husky has significant production, gathering and processing facilities throughout the Western Canada Sedimentary Basin. In the Lloydminster heavy oil prone area Husky has a well established position with extensive and concentrated landholdings, producing, gathering and processing facilities as well as heavy crude oil pipeline, upgrading and refining facilities.

At December 31, 2002, Husky was the operator of properties which accounted for approximately 87% of its total working interest production in Western Canada. Husky's undeveloped landholdings in the Western Canada Sedimentary Basin totalled 7.2 million net acres at December 31, 2002.

In the foothills deep basin areas in Alberta Husky operates the Ram River gas plant and has interests in properties that feed the plant including: Blackstone, Ricinus, Limestone, Clearwater, Benjamin, Brown Creek and Stolberg. Husky also has an interest in the Caroline gas plant and field. Further north Husky has interests in the Valhalla and Wapiti crude oil and natural gas fields near Grand Prairie and properties in the Edson area. In north-eastern British Columbia, Husky holds natural gas interests in the Sikanni and Federal area as well as Boundary Lake.

In the plains region of north-west Alberta Husky operates the Rainbow Lake Plant, miscible floods and properties in surrounding areas. Husky has extensive interests in the Peace River Arch, Boyer, Sloat Creek, Marten Hills, Cherpeta and Simons Lake areas. In the east central region of Alberta Husky has extensive property holdings east of Calgary and around Red Deer and Edmonton including major properties at Hussar and Provost.

In southern Alberta and Saskatchewan Husky has extensive property holdings around Taber, Brooks, Jenner and Suffield in southern Alberta and primarily throughout south-western Saskatchewan at Shackleton, Cantaur, Fosterton and Carnduff.

Husky has extensive experience in development, production, transportation and upgrading of heavy crude oil. Husky also has considerable experience and expertise in enhanced recovery of crude oil and horizontal drilling, as well as in natural gas exploration in the foothills along the Canadian Rocky Mountains.

On the east coast of Canada Husky holds a 12.51% working interest in the Terra Nova oil field, which began producing light crude oil in January 2002, and a 72.5% working interest in the White Rose oil field, which was sanctioned in March 2002 and is currently under development.

First oil at the White Rose oil field is currently expected prior to the end of 2005. Husky also holds interests in several exploration and significant discovery licenses in the Jeanne d'Arc Basin.

Husky holds a 40% working interest in the Wenchang oil fields located offshore in the South China Sea. Production at the Wenchang oil fields began in July 2002. Husky also holds interests in several exploration blocks in the South China Sea

Midstream Business

Husky's midstream operations include upgrading of heavy crude oil feedstock into synthetic crude oil, pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas, and cogeneration of electrical and thermal energy, and marketing of Husky's and third party produced crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Refined Products Business

Husky's refined products operations include refining of heavy and light crude oil, marketing of refined petroleum products, including asphalt and alternate fuels, and processing of grain primarily for ethanol production. Husky sells and distributes transportation fuels including ethanol blended fuels through 571 independently operated Husky and Mohawk branded petroleum outlets, including service stations, truck stops and bulk distribution facilities located from the west coast of Canada to the eastern border of Ontario, some of which include 24 hour restaurants, convenience stores, service bays, car washes, fast food sales, bank machines and propane sales.

Upstream Operations

Production

The following table shows Husky's average gross and net daily production of crude oil and NGL and natural gas for the periods indicated.

		Three Months Ended			
	Total 2002	Dec. 31, 2002	Sept. 30, 2002	June 30, 2002	March 31, 2002
Crude Oil			*(mbbls/day)*		
Light and medium crude oil and NGL[1]	125.9	137.8	131.4	116.6	117.5
Lloydminster heavy crude oil[1]	79.4	83.9	80.0	76.9	76.9
Total Gross[2]	205.3	221.7	211.4	193.5	194.4
Net[2]	179.3	190.5	180.7	171.2	174.9
Natural Gas			*(mmcf/day)*		
Gross[2]	569.2	577.4	561.6	571.8	566.0
Net[2]	426.6	435.0	423.7	422.6	424.9

Notes:

(1) Light and medium crude oil includes crude oil that is 20° API gravity or higher, as well as NGL. Heavy crude oil includes crude oil that is lower than 20° API gravity in the Lloydminster area.

(2) Gross volumes are Husky's lessor royalty, overriding royalty and working interest share of production before deduction of royalties. Net volumes are Husky's gross volumes, less royalties.

Production, continued

	Three Months Ended				
	Total 2001	Dec. 31, 2001	Sept. 30, 2001	June 30, 2001	March 31, 2001
Crude Oil			*(mbbls/day)*		
Light and medium crude oil and NGL[1]	112.0	111.3	112.7	108.6	115.5
Lloydminster heavy crude oil[1]	65.4	75.0	69.1	60.3	56.9
Total Gross[2]	177.4	186.3	181.8	168.9	172.4
Net[2]	154.1	164.4	155.1	147.6	149.3
Natural Gas			*(mmcf/day)*		
Gross[2]	572.6	568.7	567.1	570.8	584.0
Net[2]	417.8	427.1	426.0	385.0	433.0

Notes:

(1) Light and medium crude oil includes crude oil that is 20° API gravity or higher, as well as NGL. Heavy crude oil includes crude oil that is lower than 20° API gravity in the Lloydminster area.

(2) Gross volumes are Husky's lessor royalty, overriding royalty and working interest share of production before deduction of royalties. Net volumes are Husky's gross volumes, less royalties.

Capital Expenditures

The following table shows the dollar amounts expended by the Company on property acquisitions, exploration and development for the periods indicated.

	Three Months Ended				
($ millions)	Total 2002	Dec. 31, 2002	Sept. 30, 2002	June 30, 2002	March 31, 2002
Property acquisitions	$ 108	$ 50	$ 24	$ 21	$ 13
Exploration (including drilling)	286	76	58	20	132
Development (including facilities)	1,173	306	318	291	258
	$1,567	$432	$400	$332	$ 403

	Three Months Ended				
	Total 2001	Dec. 31, 2001	Sept. 30, 2001	June 30, 2001	March 31, 2001
Property acquisitions[1]	$ 177	$ 38	$112	$ 19	$ 8
Exploration (including drilling)	267	69	49	65	84
Development (including facilities)	873	246	226	174	227
	$1,317	$353	$387	$258	$319

Note:

(1) Does not include the acquisition of Titanium Oil & Gas Ltd. and Avid Oil & Gas Ltd.

Sales Prices and Lifting Costs

The following table shows the Company's average sales prices, before and after the effect of production hedging, and royalties, for light and medium crude oil and NGL, Lloydminster heavy crude oil and natural gas and average lifting costs on a boe basis for the periods indicated.

		Three Months Ended				
		Total 2002	**Dec. 31, 2002**	**Sept. 30, 2002 2002**	**June 30, 2002**	**March 31, 2002**
Before the effect of hedging						
Light and medium crude oil and NGL [1]	*($/bbl)*	$33.16	$35.99	$36.72	$32.42	$26.17
Lloydminster heavy crude oil	*($/bbl)*	$26.09	$25.47	$30.94	$27.02	$20.68
Natural gas	*($/mcf)*	$ 3.83	$ 4.76	$ 3.42	$ 3.98	$ 3.10
Realized prices (after the effect of hedging)						
Light and medium crude oil and NGL[1]	*($/bbl)*	$33.28	$36.64	$36.72	$32.42	$26.17
Lloydminster heavy crude oil	*($/bbl)*	$26.09	$25.47	$30.94	$27.02	$20.68
Natural gas	*($/mcf)*	$ 3.83	$ 4.76	$ 3.42	$ 3.98	$ 3.10
Royalties						
Light and medium crude oil and NGL[1]	*($/bbl)*	$ 4.87	$ 5.26	$ 5.42	$ 4.99	$ 3.65
Lloydminster heavy crude oil	*($/bbl)*	$ 3.08	$ 3.90	$ 4.17	$ 2.48	$ 1.60
Natural gas	*($/mcf)*	$ 0.70	$ 0.90	$ 0.55	$ 0.85	$ 0.50

		Three Months Ended				
		Total 2001	**Dec. 31, 2001**	**Sept. 30, 2001**	**June 30, 2001**	**March 31, 2001**
Before the effect of hedging						
Light and medium crude oil and NGL[1]	*($/bbl)*	$27.19	$19.44	$31.74	$28.86	$28.72
Lloydminster heavy crude oil	*($/bbl)*	$15.85	$10.44	$23.65	$15.52	$13.81
Natural gas	*($/mcf)*	$ 5.47	$ 3.01	$ 3.25	$ 6.57	$ 9.05
Realized prices (after the effect of hedging)						
Light and medium crude oil and NGL[1]	*($/bbl)*	$27.19	$19.44	$31.74	$28.86	$28.72
Lloydminster heavy crude oil	*($/bbl)*	$15.85	$10.44	$23.65	$15.52	$13.81
Natural gas	*($/mcf)*	$ 5.47	$ 3.01	$ 3.25	$ 6.57	$ 9.05
Royalties						
Light and medium crude oil and NGL[1]	*($/bbl)*	$ 5.17	$ 3.64	$ 6.26	$ 5.33	$ 5.45
Lloydminster heavy oil	*($/bbl)*	$ 1.25	$ 0.08	$ 2.33	$ 1.31	$ 1.42
Natural gas	*($/mcf)*	$ 1.25	$ 0.59	$ 0.61	$ 2.02	$ 2.26

Note:

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(1) Light and medium crude oil includes crude oil that is 20° API gravity or higher, as well as NGL. Heavy crude oil includes crude oil that is lower than 20° API gravity in the Lloydminster area.

Oil and Gas Netbacks [1]

The following table shows the Company's average netback for operations classified as light and medium crude oil operations, Lloydminster heavy crude oil operations and natural gas operations for the periods indicated. The classification is based on the oil/gas ratio. The prior year netbacks have been restated to reflect current year classification of certain wellhead and mineral taxes as royalties instead of operating costs.

		Three Months Ended				
		Total 2002	Dec. 31, 2002	Sept. 30, 2002	June 30, 2002	March 31, 2002
Light and medium crude oil	*($/boe)*					
Sales revenue		$33.02	$36.13	$36.18	$32.33	$26.08
Royalties		4.47	4.73	5.09	4.63	3.28
Operating costs		7.35	7.11	7.35	7.30	7.61
G&A		0.41	0.41	0.53	0.30	0.38
Netback		$20.79	$23.88	$23.21	$20.10	$14.81
Lloydminster heavy crude oil	*($/boe)*					
Sales revenue		$26.02	$25.50	$30.82	$27.00	$20.47
Royalties		2.97	3.79	4.05	2.25	1.59
Operating costs		7.03	8.49	6.14	6.94	6.42
G&A		0.41	0.41	0.53	0.30	0.38
Netback		$15.61	$12.81	$20.10	$17.51	$12.08
Natural gas	*($/mcfge)*					
Sales revenue		$ 3.96	$ 4.98	$ 3.60	$ 4.05	$ 3.19
Royalties		0.82	1.05	0.65	0.95	0.59
Operating costs		0.70	0.75	0.76	0.71	0.57
G&A		0.07	0.07	0.09	0.05	0.06
Netback		$ 2.37	$ 3.11	$ 2.10	$ 2.34	$ 1.97
Total Company Netbacks	*($/boe)*					
Sales revenue		$28.17	$31.35	$30.31	$28.21	$22.25
Royalties		4.20	4.98	4.45	4.35	2.90
Operating costs		6.24	6.66	6.19	6.19	5.88
G&A		0.41	0.41	0.53	0.30	0.38
Netback		$17.32	$19.30	$19.14	$17.37	$13.09

		Three Months Ended				
		Total 2001	Dec. 31, 2001	Sept. 30, 2001	June 30, 2001	March 31, 2001
Light and medium crude oil	*($/boe)*					
Sales revenue		$27.42	$19.18	$31.57	$29.51	$29.70
Royalties		4.87	3.33	5.99	5.00	5.32
Operating costs		7.47	8.42	7.55	7.50	6.29
G&A)		0.42	0.50	0.51	0.42	0.25
Netback		$14.66	$ 6.93	$17.52	$16.59	$17.84
Lloydminster heavy crude oil	*($/boe)*					
Sales revenue		$16.00	$10.48	$23.63	$15.73	$14.27
Royalties		1.27	0.11	2.29	1.54	1.27
Operating costs		7.60	7.08	7.30	8.11	8.13
G&A		0.42	0.50	0.51	0.42	0.25

Netback	$ 6.71	$ 2.79	$13.53	$ 5.66	$ 4.62

		Three Months Ended				
		Total 2001	Dec. 31, 2001	Sept. 30, 2001	June 30, 2001	March 31, 2001
Natural gas	*($/mcfge)*					
Sales revenue		$ 5.39	$ 3.06	$ 3.34	$ 6.42	$ 8.75
Royalties		1.30	0.65	0.69	1.57	2.27
Operating costs		0.58	0.67	0.66	0.57	0.43
G&A		0.07	0.08	0.09	0.07	0.04
Netback		$ 3.44	$ 1.66	$ 1.90	$ 4.21	$ 6.01
Total Company Netbacks	*($/boe)*					
Sales revenue		$26.42	$16.55	$25.50	$29.59	$34.80
Royalties		5.04	2.67	4.38	5.78	7.52
Operating costs		6.08	6.54	6.24	6.19	5.31
G&A		0.42	0.50	0.51	0.42	0.25
Netback		$14.88	$ 6.84	$14.37	$17.20	$21.72

Note:

(1) Netbacks reflect the results of operations for leases classified as oil or natural gas. Co-products, such as natural gas produced at an oil property or natural gas liquids produced at a natural gas property, have been converted to equivalent units of oil or natural gas depending on the lease classification.

Producing Wells

The following table presents the number of wells that were producing or capable of producing at December 31, 2002 in which Husky held a working interest.

	Oil Wells		Natural Gas		Total	
As at December 31, 2002	Gross(1)(2)	Net(1)	Gross(1)(2)	Net(1)	Gross(1)	Net(1)
Canada						
Alberta	5,129	3,491	4,382	2,128	9,511	5,619
Saskatchewan	4,568	3,276	479	261	5,047	3,537
British Columbia	200	56	27	11	227	67
Manitoba	3	1			3	1
Newfoundland	6	1			6	1
	9,906	6,825	4,888	2,400	14,794	9,225
International						
China	21	8			21	8
Libya	2	1			2	1
	23	9			23	9
	9,929	6,834	4,888	2,400	14,817	9,234

Notes:

(1) The number of gross wells is the total number of wells in which Husky owns a working interest. The number of net wells is the sum of the fractional interests owned in the gross wells.

(2) Includes 197 gross oil wells and 278 gross natural gas wells which were completed in two or more formations and from which the production is not commingled. For the purposes of this table multiple completions are counted as single wells. Where one of the completions in a given well is an oil completion, the well is classified as an oil well.

Drilling Activity

Husky's gross and net exploratory and development drilling activities in Western Canada for the years ended December 31, 2002 and 2001 are set forth on page 48 of Husky's 2002 Annual Report and is incorporated herein by reference.

Reserves

Husky's oil and gas reserves as of December 31, 2002 are based on constant prices and costs as prepared internally by Husky's engineers. Husky uses a formalized process for determining, approving and booking reserves. This process provides for all reserves evaluation to be done on a consistent basis using established definitions and guidelines. Approval of any significant reserve additions and changes requires review by an internal panel of qualified technical experts.

The Company's engineers determined Husky's oil and gas reserves as of December 31, 2002 and approximately 65% of the Company's proved oil and gas reserves were reviewed by McDaniel and Associates Consultants Ltd. In the opinion of McDaniel and Associates Consultants Ltd. the properties included in the review were determined in accordance with generally accepted reserves determination methods and in sufficient detail to provide confident estimates of proved reserves for the aggregate reserves reviewed. McDaniel and Associates Consultants Ltd. further indicated that their reserves estimates for the aggregate of the properties included in the review were approximately 10% lower than Husky's reserves estimates for the same properties.

The following table presents Husky's proved producing, proved non-producing and probable reserves and associated future net cash flows as at December 31, 2002. Future net revenues, based on constant prices and costs, are presented net of royalties, operating costs and future development costs and prior to deductions for overhead, interest and income tax charges. Estimated future net revenues based on constant prices and costs assume continuation of year end economic conditions including market demand and government policy, which are subject to uncertainty and may differ materially in the future. It should not be assumed that the discounted value of estimated future net reserves is representative of the fair market value of the reserves.

	Crude oil & NGL *(mmbbls)*		**Natural Gas** *(bcf)*		**Future Net Cash Flows Before Tax(3)(4)** *($ millions)*		
	Gross(1)	**Net(1)**	**Gross(1)**	**Net(1)**	**Undiscounted**	**10%**	**15%**
Proved producing(2)	422.5	374.0	1,297.1	1,063.0	$14,961	$ 8,848	$ 7,635
Proved non-producing(2)	146.7	126.8	797.4	649.7	5,850	2,998	2,338
Proved(2)	569.2	500.8	2,094.5	1,712.7	20,811	11,846	9,973
Probable(2)	452.2	403.4	402.8	321.3	11,420	5,321	3,925
Total	1,021.4	904.2	2,497.3	2,034.0	$32,231	$17,167	$13,898

Notes:

(1) Gross reserves are Husky's lessor royalty, overriding royalty and working interest share of reserves, before deduction of royalties. Net reserves are gross reserves, less royalties.

(2) These reserve categories have the same meanings as those set out in National Policy Statement #2B.

(3) The discounted future net cash flows at December 31, 2002 were based on the year-end spot NYMEX natural gas price of U.S. $4.60/mmbtu and on a spot WTI crude oil price of U.S. $31.21/bbl.

(4)

Future Capital Costs ($ millions undiscounted)	**Total**	**2003**	**2004**
Proved developed	$ 450	$ 85	$ 38
Proved undeveloped	837	272	165
	1,287	357	203
Probable	2,196	587	545
	$3,483	$944	$748

Future capital costs include estimated development capital expenditures necessary to gain access to proved undeveloped reserves and probable

reserves as well as estimated capital expenditures necessary to maintain production of proved developed reserves.

Reserve Reconciliation

Reconciliation of the gross reserves and net reserves of Husky are set forth on pages 94 and 91, respectively, of Husky's 2002 Annual Report and are incorporated herein by reference.

Reserves and Production by Principal Area

Husky's estimate of its proved reserves by area as of December 31, 2002 and daily average production of crude oil, NGL and natural gas by area are as follows:

Light/Medium Crude Oil and NGL

	Proved Reserves (mmbbls)	Production (mbbls/day)
Canada		
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	31.3	7.8
Foothills Deep Gas area	23.3	7.3
Ram River area	3.1	0.7
Northwest Alberta Plains		
Rainbow Lake area	85.1	8.8
Peace River Arch area	10.8	3.8
East Central Alberta		
Provost area	41.5	24.9
North area	1.5	0.8
South area	5.6	3.2
Southern Alberta and Saskatchewan		
South Alberta area	24.5	16.8
South Saskatchewan area	76.3	21.3
Lloydminster Area		
Wainwright/Wildmere area	16.5	4.5
Other	0.9	0.3
	320.4	100.2
East Coast Canada	31.0	13.2
	351.4	113.4
International		
China	30.1	12.2
Indonesia	6.4	
Libya	0.6	0.3
	388.5	125.9
Lloydminster Heavy Crude Oil		
Lloydminster area		
Primary production	115.1	68.4
Thermal production	65.6	11.0
	180.7	79.4
	569.2	205.3

Natural Gas

Western Canada	Proved Reserves (bcf)	Production (mmcf/day)
British Columbia and Foothills		
Alberta and BC Plains area	108.9	32.4
Foothills Deep Gas area	230.7	97.3
Ram River area	256.7	66.9
Northwest Alberta Plains		
Rainbow Lake area	248.8	16.9
Northern Alberta area	489.8	133.4
East Central Alberta		
Provost area	51.2	13.3
North area	137.1	58.7
South area	146.0	61.1
Southern Alberta and Saskatchewan		
South Alberta area	31.4	15.8
South Saskatchewan area	147.7	21.9
Lloydminster Area	87.6	44.3
Other	15.7	7.2
	1,951.6	569.2
International		
Indonesia	142.9	—
	2,094.5	569.2

Landholdings

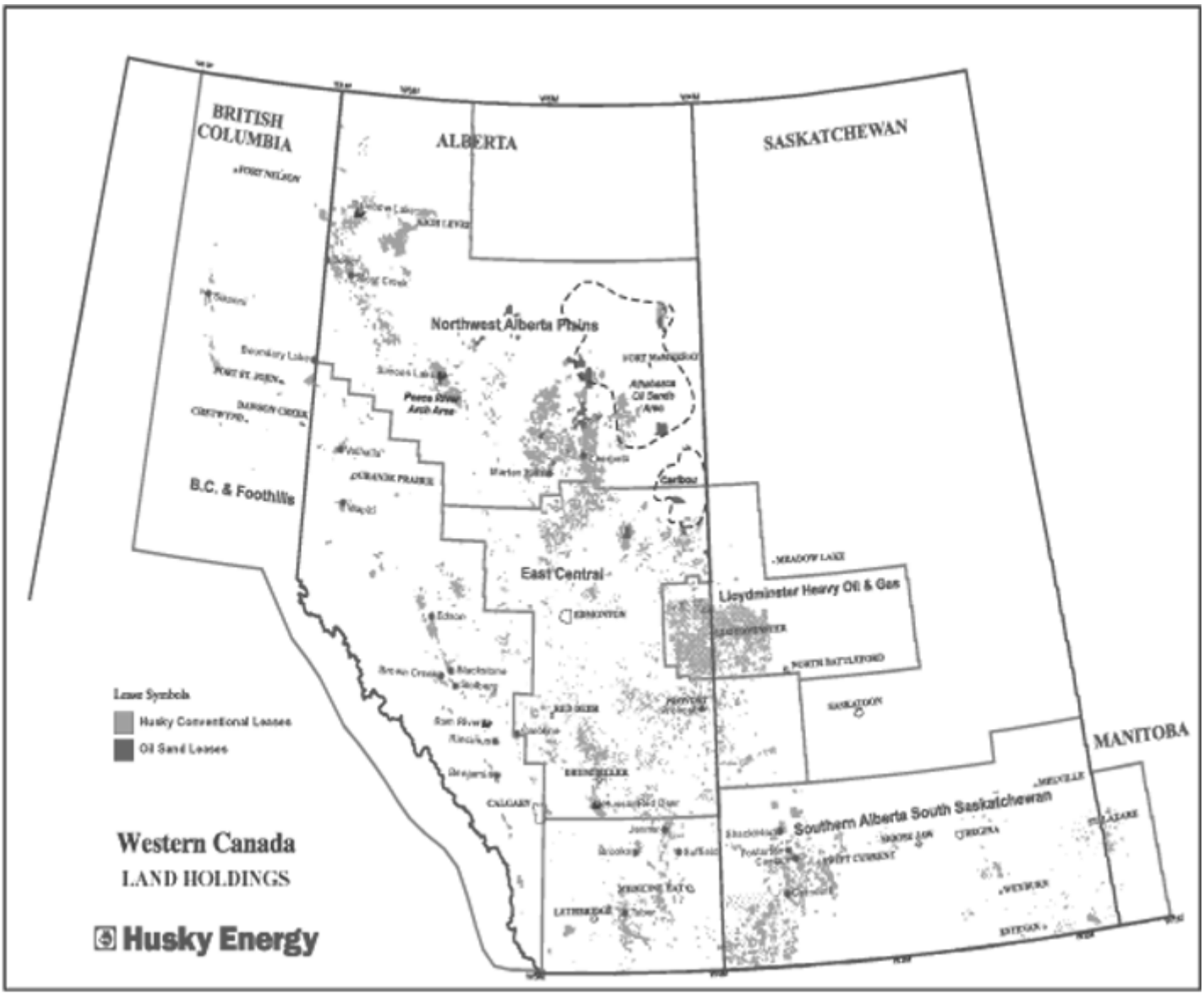
Husky's undeveloped acreage as at December 31, 2002 is set forth on page 48 of Husky's 2002 Annual Report and is incorporated herein by reference. Husky's developed acreage as at December 31, 2002 is summarized below:

	Developed Acreage	
	Gross	Net
	(thousands of acres)	
Western Canada		
Alberta	2,863	2,443
Saskatchewan	523	465
British Columbia	101	63
Manitoba	1	1
	3,488	2,972
Eastern Canada	35	4
	3,523	2,976
China	17	7
Libya	7	2
	3,547	2,985

Description of Major Properties and Facilities

Husky's portfolio of producing assets in Western Canada include properties that produce light, medium and heavy gravity crude oil, NGL, natural gas and sulphur. Husky's upstream strategy in Western Canada in recent years has been to further delineate and exploit its core producing areas and to increase its interest in such areas through selective asset acquisitions, divestitures and trades. Husky believes that it can benefit from both operating efficiencies and increased control over the development strategy and the pace of capital investment in these areas.

Husky assembled a cost management team in order to continue to focus on operating cost management and production optimization efforts. A group of experienced engineering and operating staff work with the business unit and field teams to identify and quantify opportunities to reduce costs and improve reliability and increase efficiency of core assets. Once this multi-discipline team has evaluated and prioritized opportunities, projects are returned to the business unit for approval and execution. As the cost management team reviews more assets, it will be able to pass on best practices to other operating areas.



LLOYDMINSTER HEAVY OIL AND GAS

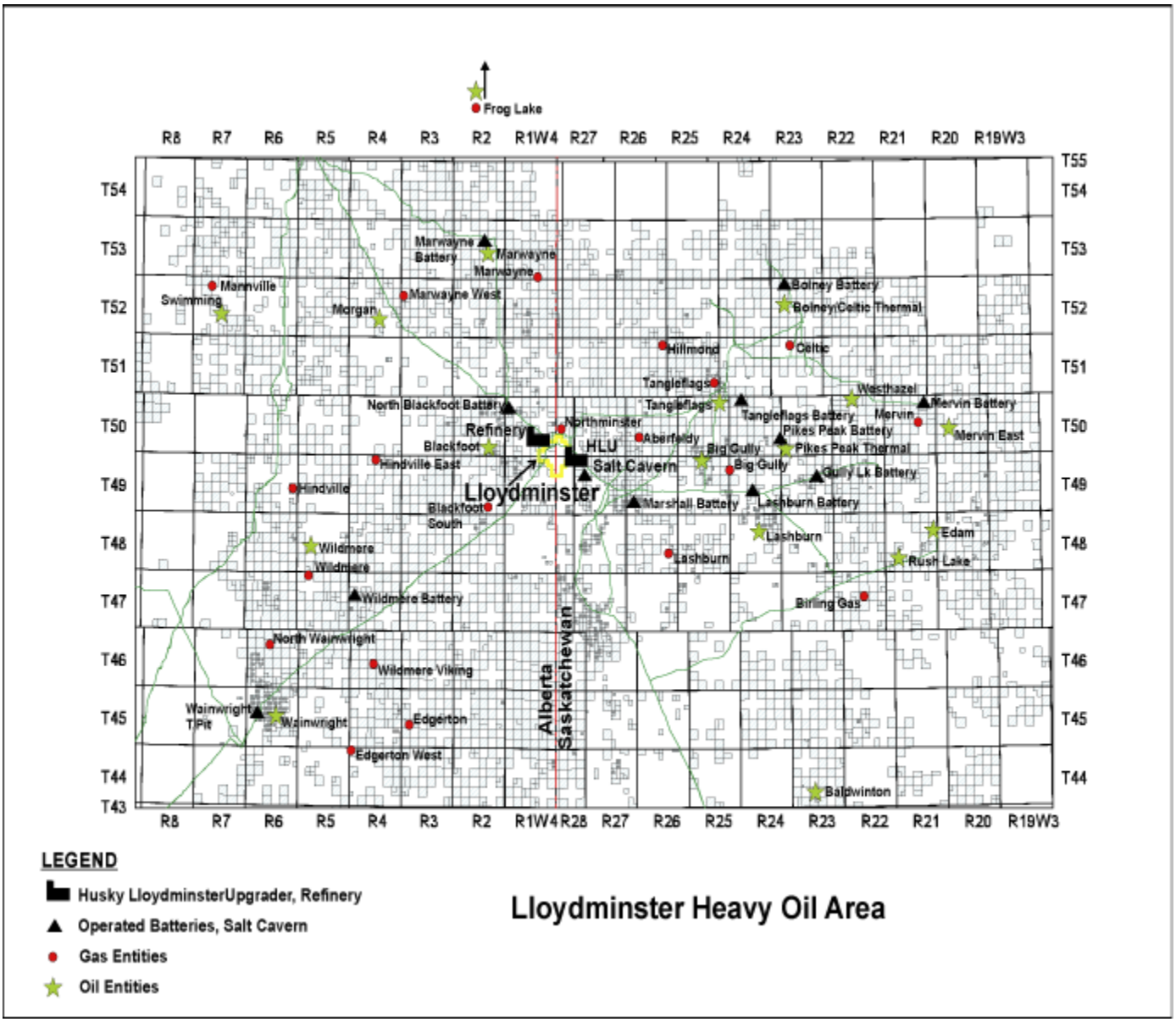
Husky's heavy oil assets are concentrated in a large producing area covering more than 14,800 square kilometres in the Lloydminster area in the provinces of Saskatchewan and Alberta. Approximately 80% of Husky's proved reserves in the region are contained in the heavy crude oil producing fields of Pikes Peak, Edam, Tangleflags, Celtic, Bolney, Westhazel, Big Gully, Hillmond, Mervin, Marwayne, Lashburn, Baldwinton and Rush Lake, and in the medium gravity crude oil producing fields of Wildmere and Wainwright. These fields contain extensive accumulations of heavy crude oil at relatively shallow depths. Husky maintains a land position of approximately 1.5 million net acres in the Lloydminster area, of which approximately two-thirds is undeveloped.

Husky currently produces from oil and gas wells ranging in depth from 455 to 700 metres and holds a 100% working interest in the majority of these wells. Husky produces heavy oil from the Lloydminster area using a variety of techniques, including standard primary production methods, as well as steam injection and horizontal well technology. Husky has increased primary production from the area through cold production techniques which utilize progressive cavity pumps capable of simultaneous production of sand and heavy oil from unconsolidated formations. Husky's gross heavy and medium crude oil production from the area totalled 83.9 mbbls/day in 2002. Approximately 68.4 mbbls/day of that total was primary production of heavy crude oil, approximately 11.0 mbbls/day was production from Husky's Pikes Peak cyclic steam operation and Bolney/Celtic thermal project and approximately 4.5 mbbls/day was from the medium gravity waterflooded fields in the Wainwright and Wildmere areas. Husky believes that the future growth from this area will be driven by primary heavy oil production and new thermal projects.

Husky's infrastructure in the Lloydminster area is extensive. Husky owns and operates 16 oil treating facilities, all of which are tied into Husky's heavy oil pipeline systems. These pipeline systems transport heavy crude oil from the field locations to Husky's Lloydminster asphalt refinery, to the Husky Lloydminster Upgrader and to the Enbridge Pipeline and Express Pipeline systems at Hardisty, Alberta.

Husky is focused on increasing its heavy oil production and believes that its undeveloped land position in the Lloydminster area, coupled with the application of improved technologies, a reduced cost structure and increased upgrading capacity, will provide strong growth opportunities for heavy oil production.

Husky also produces natural gas from shallow natural gas pools in the Lloydminster area that are generally small (approximately 1 to 2 bcf of proved reserves), but numerous. Husky's total gross natural gas production from the area was 44.3 mmcf/day during 2002.



NORTHWEST ALBERTA PLAINS

Rainbow Lake Area

Rainbow Lake, located approximately 900 kilometres north-west of Edmonton, Alberta, is the site of Husky's largest light oil production operation in Western Canada. Husky operates a number of crude oil pools in the Rainbow basin, with an average working interest of 54%. Husky's production in this area is derived from more than 50 oil and gas pools extending over 1,300 square kilometres.

Husky uses secondary and tertiary oil recovery methods extensively in the Rainbow Lake area. Husky has developed considerable expertise in these methods, which include injecting water, natural gas and NGL into the oil reservoirs to enhance crude oil recovery. The use of tertiary recovery programs, such as miscible floods, has increased the estimated amount of recoverable

crude oil-in-place from 50% to 70% of the original crude oil-in-place in certain pools. As a consequence of implementing these natural gas and NGL re-injection programs, historically only small volumes of gas and NGL have been marketed from the Rainbow Lake area prior to 2002. In 2002, Husky initiated the recovery of natural gas from several and pools. NGL recovery is forecast to begin in the 2005-2008 timeframe and is expected to generate revenues once crude oil production from the pools is complete. Husky uses horizontal drilling techniques, including the re-entry of existing wellbores, to maintain crude oil production and to increase recovery rates. Husky is continuing exploration efforts to supplement its development initiatives in the Rainbow Lake area. Husky's gross production from this area averaged 8.8 mbbls/day of light crude oil and NGL and 16.9 mmcf/day of natural gas during 2002.

Husky holds a 50% interest in, and operates, the Rainbow Lake processing plant. The processing design rate capacity of the plant is 69 mbbls/day of crude oil and water and 230 mmcf/day of raw gas. The extraction design capacity is 17 mbbls/day of NGL. The plant currently is operating at near capacity levels. A 100 mmcf/day high inlet pressure plant expansion was commissioned in the fourth quarter of 2001 to accelerate oil recovery, and to accommodate additional gas volumes resulting from the exploration effort.

Peace River Arch Area

The Peace River Arch area of northern Alberta, which includes the Red Earth, Seal, Utikuma, Lubicon and other properties, is a major light oil producing area located approximately 370 kilometres north-west of Edmonton. Husky operates and holds an average 80% working interest in several properties in this area. Over the last three years, Husky has maintained gross production from properties in this area, at approximately 3.8 mbbls/day of crude oil, through acquisitions, stepout drilling and waterflood optimization. Husky plans to increase its exploration for both crude oil and natural gas targets in this area.

Boyer Area

The Boyer area of Alberta is approximately 600 kilometres north-west of Edmonton, Alberta. Husky is the operator and holds approximately 450,000 net acres. The area holds a shallow, Bluesky gas reservoir that is characterized as low deliverability and low decline that is being developed with a drilling density of two wells per section. Husky intends to continue to develop this area by drilling undeveloped sections and infill drilling. Gross production from this area in 2002 averaged 26 mmcf/day of natural gas.

Sloat Creek Area

The Sloat Creek or Chinchaga area of Alberta is located close to the British Columbia border approximately 570 kilometres north-west of Edmonton, Alberta. Husky is the operator and holds an approximate 95% working interest in 230,000 acres of gas prone land. The Bluesky, DeBolt, Elkton and Shunda zones that lie an average of approximately 1,030 metres deep and the Slave Point zone at an average depth of 1,800 metres characterize the area. Husky intends to continue to develop this area with infill, stepout and exploratory drilling so that existing pools can be optimized and new pools can be placed on production.

Husky owns a 30 mmcf/day high pressure booster compression plant that feeds a third party operated sour gas plant and is 50% owner in a 12 mmcf/day low pressure booster that feeds a 40% owned sweet gas processing facility operated by a third party. Gross production from this area averaged 16.4 mmcf/day of natural gas in 2002.

Marten Hills Area

The Marten Hills Area of Alberta is located 212 kilometres north-west of Edmonton, Alberta. Husky is the operator and holds 578,000 net acres of gas prone land. The Clearwater, Colony, McMurray and Wabiskaw zones that lie at an average depth of 600 metres characterize the area.

Husky intends to continue to develop this area with infill, stepout and exploratory drilling so that existing pools can be optimized and new pools can be placed on production.

Husky owns a 100% interest in a series of nine sales compressor stations, a 95% interest in a compressor station at Rock Island, a 37.5% interest in a third party operated facility at Peerless and a 3% interest in the third party operated Marten Hills unit. Husky also processes its 100% working interest non-unit gas through the Marten Hills unit facility. Gross production from this area averaged 43 mmcf/day of natural gas in 2002.

Cherpeta and Saleski Areas

The Cherpeta area of Alberta is located 230 kilometres north of Edmonton, Alberta and the Saleski area is located approximately 140 kilometres further north from Cherpeta. Husky is the operator and holds an interest in 580,000 net acres of gas prone land. The Nisku, Clearwater, Colony, McMurray and Wabiskaw zones that lie at an average depth of 600 metres characterize the area. The Grosmont zone that lies between 450 and 500 metres characterizes the Saleski area. Husky intends to continue to develop this area with infill, stepout and exploratory drilling so that existing pools can be optimized and new pools can be placed on production.

Husky owns on average from 60-95% working interest in the Cherpeta area and 49% of the Saleski area and operates a series of sales compressor stations, gas plants and sales pipeline. Gross production from these areas averaged 39.5 mmcf/day of natural gas in 2002.

Simons Lake Area

The Simons Lake area of Alberta is located 386 kilometres north-west of Edmonton, Alberta. Husky is the operator and holds 275,000 net acres of gas prone land. The Bluesky, DeBolt, Elkton and Shunda zones that lie at an average depth of 600 metres characterize the area.

Husky holds 100% working interest in a 10 mmcf/day sour gas processing facility and 34% working interest in a high pressure booster station operated by a third party that feeds a separate third party owned sour gas processing facility. Gross production from this area averaged 6.3mmcf/day of natural gas in 2002.

BRITISH COLUMBIA AND FOOTHILLS

Ram River Area

The Ram River area is located in west central Alberta and includes the large Blackstone, Ricinus and Clearwater/Limestone natural gas fields.

The Blackstone field is the most prolific of these fields and contains four high deliverability natural gas wells, capable of combined raw gas production of 122 mmcf/day. Husky holds a 34% interest in three unitized wells and a 50% interest in a fourth well, and acts as the contract operator of the Blackstone wells. Production from these wells is processed at the Husky operated Ram River gas plant.

Husky holds an average 72% interest in, and is the operator of, the Ram River sour gas plant and related processing facilities. The Ram River plant has the capacity to process 622 mmcf/day of sour gas, resulting in sales gas capacity of 525 mmcf/day. The plant also has the capacity to produce in excess of 2.8 mlt/day of sulphur from raw gas. During 2002, the plant operated at approximately 90% of its design rate capacity. The Ram River plant processes in excess of 11% of Husky's total gross natural gas production, which includes an average of 40.0 mmcf/day of Husky gross sales gas from the Blackstone, Brown Creek and Stolberg fields and an average of 23.6 mmcf/day of Husky production from Ricinus and Clearwater/Limestone and Benjamin

fields, in addition to processing third-party volumes. In addition, gross production from Ferrier, which is processed at another gas plant, averaged 3.3 mmcf/day of natural gas bringing the total production of natural gas from the Ram River area to 66.9 mmcf/day in 2002.

Husky's sour gas pipeline network supports the Ram River plant. Husky operates a network of 845 kilometres of sour gas pipelines in the Ram River area and holds a 30% interest in 684 kilometres of this pipeline system. The sour gas processed at the Ram River plant is produced from 18 sour gas fields located as far as 145 kilometres from the Ram River plant.

Husky believes that the Ram River plant and the extensive infrastructure of gathering pipelines, transmission systems and rail lines, which support the plant, represents a strategic base for the natural gas exploration and development planned by Husky in this part of the foothills region. In addition, this region is an active exploration and production area for other producers and provides additional opportunities for generating revenue by processing third party natural gas.

Boundary Lake Area

Husky holds a 50% working interest in the Boundary Lake Gas Unit and 19% to 34% interest in the Boundary Lake oil unit in north-east British Columbia. Husky's natural gas production from this area is derived from five Belloy sour gas pools, which is processed at the nearby Boundary Lake processing plant. Husky's gross production from this area was 17 mmcf/day of natural gas and 2.2 mbbls/day crude oil and NGL from the Boundary Lake units during 2002.

Valhalla and Wapiti Area

Husky holds a 30% interest in three Valhalla oil units, a 100% interest in 350 Valhalla non-unit waterflood wells and a 100% interest in the Wapiti property. Production is primarily from the Doe Creek and Cardium zones and consists of light crude oil, natural gas liquids and natural gas. Husky's gross production from these properties averaged 5.5 mbbls/day of crude oil and NGL and 7.3 mmcf/day of natural gas in 2002.

Caroline Area

Husky holds an 11% working interest in the 32,000 acre Caroline natural gas field located approximately 97 kilometres north-west of Calgary. The field has a high proportion of NGL and as a result the economics of this field are enhanced.

Husky also holds an 11% interest in the Caroline sour gas processing facility. The plant is presently running at a license limit of 118% of design capacity and is processing approximately 129 mmcf/day of total plant sales gas and 45 mbbls/day of NGL. The plant and liquid acceleration gas recycle plant were at 97% capacity in 2002 which resulted in Husky gross production of 4.9 mbbls/day NGL and 13.9 mmcf/day natural gas in 2002.

Edson Area

Husky holds an average 85% working interest in two gas processing facilities and associated gas gathering systems in the Edson area. Husky operated lands in the Edson area total approximately 56,000 gross acres. Husky has an interest in approximately 150 Cardium wells in this area that averaged gross production of 29.5 mmcf/day of natural gas and 1.3 mbbls/day of NGL in 2002.

Sikanni Area

Husky holds approximately 32,000 net acres in the Sikanni and Federal area of north-east British Columbia, which averaged gross production of 26.5 mmcf/day of natural gas from four wells in 2002. The production flows through Husky owned gathering systems for processing at third party plants at the Sikanni and McMahon gas plants.

EAST CENTRAL ALBERTA

Athabasca Area

The Athabasca area is located north of Edmonton up to township 70 in the north and from the Alberta-Saskatchewan border in the east to the Alberta foothills in the west. The area target is predominantly shallow gas, ranging from 455 to 910 metres, in the multi-zone Palaeozoic Mannville. The main producing areas are Athabasca, Craigend and Cold Lake. Husky operates 31 facilities with an extensive pipeline system with an average working interest of 90% in the producing wells. Husky intends to continue to develop this area with infill, stepout and exploratory wells to optimize recovery and develop new pools in order to keep the facilities operating at capacity. Husky's gross production from this area averaged 59 mmcf/day of natural gas and 700 bbls/day of crude oil in 2002.

Red Deer and Hussar Area

The Red Deer and Hussar area falls between township 23-50 and range 1W4-5W5 with the core of the area between Calgary, Drumheller and Sylvan Lake. Husky operates 18 facilities with extensive gas gathering systems in this area. In 2002 gross production from this area averaged 61 mmcf/day of natural gas and crude oil and NGL of 3.0 mbbls/day. Husky intends to continue to develop the natural gas potential of this area with infill, stepout and exploratory wells to optimize gas recovery and develop new pools in order to operate the facilities at capacity.

Provost Area

The centre of the Provost area is approximately 240 kilometres south-east of Edmonton. It is predominantly a medium crude oil area that averaged gross production of approximately 25 mbbls/day of crude oil and 13 mmcf/day of natural gas in 2002. Husky intends to selectively drill lower risk oil locations and focus on managing operating costs and improving oil recovery. There is significant competition in the area for land as well as infrastructure. Husky has a dominant position and maintains close to 100% working interest in most of its facilities.

SOUTHERN ALBERTA AND SASKATCHEWAN

In Southern Alberta and Saskatchewan the Company sold properties, which were producing approximately 7,000 — 7,500 boe/day effective October 1, 2002. As of December 31, 2002, the Company held 1.45 million net acres in Saskatchewan and 370,000 net acres in Alberta. The Company also has a small holding in Manitoba.

Southern Saskatchewan Area

Husky is a prominent operator in south-western Saskatchewan primarily producing medium gravity crude oil, with some natural gas and light crude oil. During 2002, gross production from this area averaged 20.2 mbbls/day of crude oil and of 21.9 mmcf/day of natural gas. Properties in south-eastern Saskatchewan produced 1.1 mbbls/day of crude oil per day in 2002.

Husky operates 31 oil batteries and six gas facilities in the Southern Saskatchewan area. The oil pools in this area are exploited using pressure maintenance and waterflood recovery operations.

The Shackleton/Lacadena Milk River shallow gas project was accelerated in the last half of 2002. During that period 144 wells were drilled and two new gas facilities were built. As a result, the project was producing at a rate of 28 mmcf/day at December 31, 2002 (average December monthly production was 23 mmcf/day).

Southern Alberta Area

Taber, Brooks and Jenner/Suffield are Husky's three core areas in southern Alberta. Husky operates 28 oil facilities and three natural gas facilities with an average working interest of 95%. Oil production is mainly medium gravity crude with the majority of reserves being supported by waterfloods or active aquifers. Natural gas production is from a mixture of deep and shallow formations. At Taber, Husky is operating an alkaline-polymer flood to increase recovery from the Cretaceous Mannville reservoir. During 2002, gross production from this area averaged 16.8 mbbls/day of crude oil and 15.8 mmcf/day of natural gas.

ATHABASCA, COLD LAKE AND PEACE RIVER

Husky currently holds interests in 430,609 acres in the bitumen prone areas of Athabasca, Cold Lake and Peace River. Husky is currently conducting evaluation drilling and production feasibility studies in the Cold Lake and Athabasca areas. Recent improvements in fiscal regimes for these types of project, together with advances in technology which have reduced costs for in situ projects, have enhanced the commercial viability of these projects. In situ projects are currently being designed for the Tucker and Kearl areas.

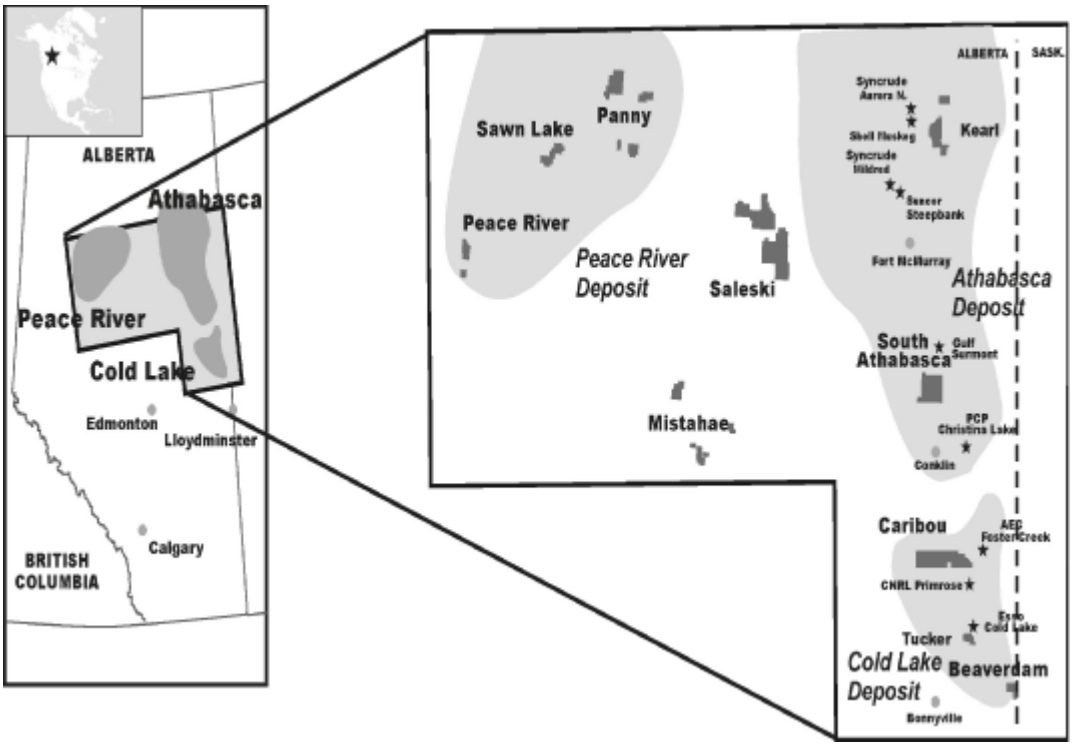
In the Athabasca area, Husky and its co-venturer recently completed an asset exchange of the Kearl properties in December 2002. Under the terms of the asset exchange, Husky increased its working interest in the in situ project area from approximately 80% to 100%. Husky also acquired an additional 25.5 net sections of 100% interest land adjacent to the project area. In exchange Husky divested its entire interest in the area designated for bitumen mining. This arrangement is expected to improve the efficiency of the exploitation of the bitumen resource.

In addition to interests in the 350,929 net acres in the Cold Lake and Athabasca regions in north-eastern Alberta, Husky holds an interest in 79,680 net acres in the Peace River region of northern Alberta.

General Location Name	Oil Sand Area	Gross Acres	Net Acres	Husky Operator
South Athabasca— over riding royalty	Athabasca	35,705	—	No
South Athabasca	Athabasca	33,058	16,529	Yes
Kearl — Insitu	Athabasca	56,800	56,800	Yes
Misthae	Athabasca	28,160	28,160	Yes
Saleski	Athabasca	154,880	154,880	Yes
Beaverdam	Cold Lake	11,520	11,520	Yes
Caribou	Cold Lake	35,840	35,840	Yes
Lobstick	Cold Lake	37,120	37,120	Yes
Tucker	Cold Lake	10,080	10,080	Yes
Panny	Peace River	47,360	47,360	Yes
Peace River	Peace River	11,840	11,840	Yes
Sawn Lake	Peace River	20,480	20,480	Yes
		482,843	430,609	

Note:

(1) Husky also has the exclusive right to acquire an additional 65,280 acres in the Caribou area.

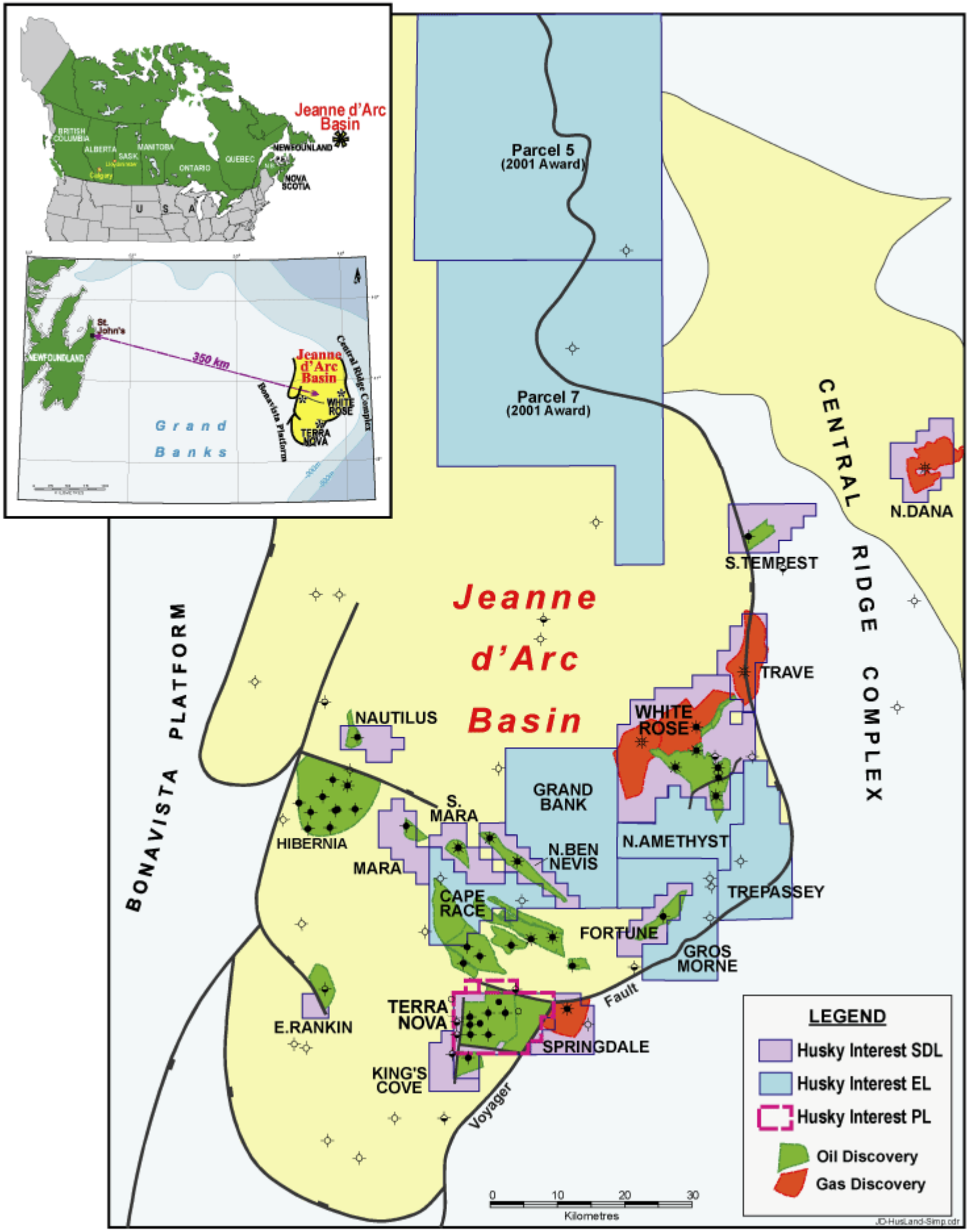


OFFSHORE EAST COAST — CANADA

Husky's offshore east coast exploration and development program is focused primarily in the Jeanne d'Arc basin on the Grand Banks offshore the coast of Newfoundland, which contains the Hibernia, Terra Nova and White Rose oil fields. Husky has ownership interests in the Terra Nova and White Rose oil fields as well as in a number of smaller fields in the central part of the basin. Husky presently holds an approximate 36% average working interest in 12 Significant Discovery License ("SDL") areas in the Jeanne d'Arc basin and a 21% average working interest in nine Exploration Licenses on the Grand Banks. Husky believes that its geotechnical expertise, drilling experience and extensive database with respect to offshore the east coast of Canada provide a strong foundation for future development. Husky believes that there is exploration potential in the area, and that its position off the east coast of Canada will provide growth opportunities for light crude oil production in the medium to long-term.

In 2002 Husky drilled two exploration wells in the Jeanne d'Arc Basin. A well (EL1044) was drilled on the Trepassey Exploration Licence and a well (EL 1055) was drilled on the Gros Morne Exploration Licence. Both structures were water bearing in the main reservoir zone. At Trepassey, hydrocarbons were encountered in a secondary zone, although not in commercial quantities.

Grand Banks - Jeanne d'Arc Basin



Terra Nova Oil Field

The Terra Nova oil field is located approximately 350 kilometres east south-east of St. John's, Newfoundland, 35 kilometres south-east of the Hibernia oil field, in 91 to 100 metres of water. The Terra Nova oil field is divided into three distinct areas, known as the Graben, the East Flank and the Far East areas.

As at December 31, 2002, there were six development wells drilled in the Graben area, three producing wells and three injection wells. In the East Flank area there were also three producing wells and three injection wells drilled. Drilling operations will continue with a 24 well depletion plan for the Graben and East Flank areas. A delineation well in the Far East Block encountered 82 metres of net pay confirming the reserve sands extend to this area and may provide additional reserves. A second well, that was intended to be a water injection well, was drilled in the Far East block. This well encountered poor porosity in the target horizon and was plugged back. The well may be re-drilled to a different location in the future. A third well may be drilled in the Far East block during 2003. During 2002, Husky booked 31.0 million barrels of crude oil to the proved oil reserves category. These reserves are estimated to be capable of being produced using primary and secondary (waterflood and gasflood) production techniques.

Husky's initial pooled interest in the Terra Nova field was 17.5%, which was subsequently reduced to 12.51% by a property exchange transaction in early 2000. This interest is subject to change, pending redetermination once the field has been further delineated. Production at Terra Nova commenced in January 2002 with an initial production rate of 110 mbbls/day of oil and averaged approximately 145 mbbls/day in the fourth quarter of 2002. Husky's share of production from Terra Nova was 4.8 million barrels in 2002.

White Rose Oil Field

The White Rose oil field, which is operated by Husky, is located 354 kilometres off the coast of Newfoundland, approximately 48 kilometres east of the Hibernia field on the eastern portion of the Jeanne d'Arc basin.

During 2001, Husky awarded the front end engineering design contracts for a floating production storage and offloading system, the subsea production system and the glory hole, a deep excavation in the sea bed to protect well heads from iceberg incursion. In that same year, a contract was entered into for the design and construction of the glory hole long lead excavation equipment. Lump sum bids were also received for the floating production storage offloading system subcontracts (comprised of hull, topsides and turret).

Husky filed a development application with Canada-Newfoundland Offshore Petroleum Board in January 2001. Following formal public review hearings, the project received the requisite regulatory approvals in December 2001 from the Canada-Newfoundland Offshore Petroleum Board, Provincial Government and Federal Government. In March 2002, Husky and its co-venturer announced their decision to proceed with the development of the White Rose oil field. Current plans provide for a total of 19 to 21 wells to be drilled to recover crude oil over a 10 to 15 year period. Annualized peak production is expected to be approximately 92,000 barrels of oil per day sustained for approximately four years. Excavation of the subsea glory holes commenced in the third quarter of 2002 and will recommence in the first half of 2003. Development drilling is expected to commence in the second half of 2003. Engineering, procurement and construction of the floating production, storage and offloading vessel and subsea facilities are progressing.

INTERNATIONAL

Offshore China

Wenchang

On October 13, 2000, Husky signed a petroleum contract with the China National Offshore Oil Corporation ("CNOOC") to develop two oil fields in the South China Sea. The oil fields are located in the western Pearl River Mouth Basin, approximately 300 kilometres south of Hong Kong and 135 kilometres east of Hainan Island.

The project was completed and commenced production in July 2002. The Company holds a 40% working interest in the project and spent approximately $253 million to first oil. The Wenchang 13-1 and 13-2 oil fields are producing from fixed platforms and 21 producing wells in 100 metres of water into a floating production, storage and offloading vessel stationed between the fields. The blended crude oil from the two fields averages approximately 35° API, similar to the benchmark Minas blend. At December 31, 2002 Husky's proved reserves at Wenchang amounted to 30.1 mmbbls of crude oil. Production from first oil in July 2002 to December 31, 2002 averaged 25.3 mbbls/day.

Block 39-05

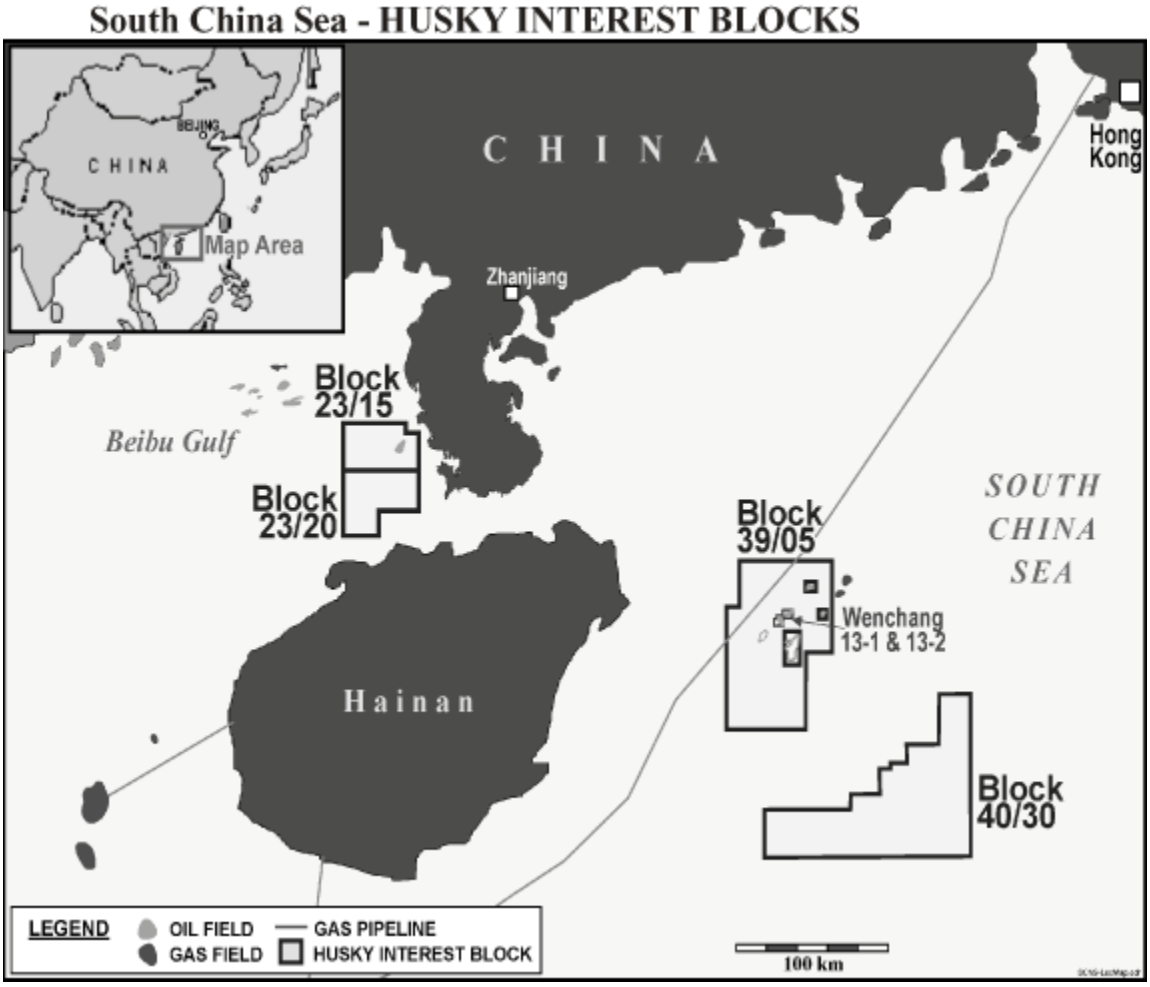
Husky executed a production sharing contract with CNOOC for the 5,740 square kilometres 39-05 Exploration Block surrounding the Wenchang 13-1/2 fields. Husky has committed to drill three exploration wells within seven years and CNOOC has the right to participate in development of any discoveries up to a 51% working interest. In January 2003 the Qionghai 18-1-3 exploration well was plugged and abandoned without testing and in February 2003 the Wenchang 8-1-1 was plugged and abandoned without testing.

Blocks 23-15 and 23-20

Husky executed a production sharing contract for the 23-15 and 23-20 exploration blocks in September 2002. Both leases are located in the South China Sea north of Hainan, within 80 kilometres of the Weizhan oil fields. The 23-15 lease is 1,327 square kilometres and the 23-20 lease is 1,543 square kilometres. The work program requires Husky to drill a single exploration well in each lease within three years. CNOOC has the right to participate in development of any discoveries up to a 51% working interest.

Block 40-30

Husky executed a production sharing contract for the 40-30 exploration block in December 2002. The lease is located in the South China Sea approximately 100 kilometres south of the 13-1 and 13-2 oil fields. The lease is 6,704 square kilometres and requires the drilling of one exploration well within three years. CNOOC has the right to participate in development of any discoveries up to a 51% working interest.



Madura Strait, Indonesia

Husky is party to a production sharing contract, which provides for various cost and production sharing arrangements, relating to a 690,412 acre block in the Madura Strait offshore Java, Indonesia. Ten exploration and appraisal wells have been drilled in the block, resulting in discoveries of two natural gas fields. The Indonesian state oil company granted commercial status and approved a plan of development for one of these fields in order to supply natural gas to a proposed independent power plant near Pasuruan, East Java. Husky and its co-venturer signed a gas supply agreement for the development in September 1997. However, the construction of the power plant and development of the natural gas field have been postponed pending resolution of energy market and finance issues arising from the economic conditions in Indonesia that occurred shortly after the contract was signed. In January 2003, Husky signed a memorandum of understanding to begin discussions intended to finalize a natural gas sales agreement for Madura production.

Shatirah, Libya

Husky has an interest in a minor crude oil production operation in the Shatirah field, onshore Libya.

DISTRIBUTION OF OIL AND GAS PRODUCTION

Crude Oil and NGL

Husky provides heavy crude oil feedstock to its upgrader and its asphalt refinery, which are located at Lloydminster. The combined dry crude feedstock requirements of the upgrader and asphalt refinery are equal to approximately 85% of Husky's heavy crude oil production from the Lloydminster area. Husky also markets heavy crude oil production directly to refiners located in the U.S. mid-west and eastern U.S. and Canada. Husky markets its light and synthetic crude oil production to third party refiners in both Canada and the United States. Natural gas liquids are sold to local petrochemical end users and refiners in North America.

Husky markets a significant amount of third party volumes of light crude oil, heavy crude oil and NGL in addition to its own production.

Natural Gas

The following table shows the distribution of Husky's gross average daily natural gas production for the years indicated:

	Years ended December 31,		
	2002	**2001**	**2000**
		(mmcf/day)	
Sales to end users			
United States	375	413	240
Canada	115	106	81
	490	519	321
Sales to aggregators	49	40	25
Internal use[1]	30	14	12
	569	573	358

Note:

(1) Husky consumes natural gas for fuel at several of its facilities.

Husky also markets a significant volume of third party natural gas production in addition to its own production.

Midstream Operations

Overview

The midstream operations of Husky include upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading), pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas, extraction of NGL from natural gas, cogeneration of electrical and thermal energy (Infrastructure) and the purchase and marketing of Husky's and other producers' crude oil, natural gas, natural gas liquids, sulphur, petroleum coke and electrical power (Marketing).

Upgrading Operations

Husky owns and operates the Husky Lloydminster Upgrader, which is a heavy oil upgrading facility located in Lloydminster, Saskatchewan.

The Husky Lloydminster Upgrader is designed to process blended heavy crude oil feedstock into high quality, low sulphur synthetic crude oil. Synthetic crude oil is used as feedstock for the refining of premium transportation fuels in Canada and the United States. In addition, the Husky Lloydminster Upgrader recovers the diluent, which facilitates pipeline transportation of heavy crude oil, from the blended heavy oil feedstock.

The Husky Lloydminster Upgrader has created a new market for heavy crude oil in Western Canada, which Husky believes has facilitated, and will continue to stimulate, heavy oil production in the area. The Husky Lloydminster Upgrader was commissioned in 1992 with an original design capacity of 46 mbbls/day of synthetic crude oil. Actual production has ranged considerably higher than the original design rate capacity as a result of throughput modifications and improved reliability. The upgrader's current rated capacity is 54 mbbls/day. Production at the upgrader averaged 55.7 mbbls/day of synthetic crude oil and 9.7 mbbls/day of diluent in 2002 compared with 59.8 mbbls/day of synthetic crude oil and 11.8 mbbls/day of diluent in 2001. Throughput at the upgrader in 2002 was lower than 2001 due to a scheduled maintenance turnaround during 2002. In addition to synthetic crude oil and diluent, the Husky Lloydminster Upgrader also produced, as by-products of its upgrading operations, approximately 311 lt/day of sulphur and 760 lt/day of petroleum coke during 2002. These products are sold in local and international markets. The profitability of Husky's upgrading operations is primarily dependent upon the differential between the price of synthetic crude oil and the price of heavy crude oil.

Infrastructure and Marketing

HEAVY OIL PIPELINE SYSTEMS AND PROCESSING FACILITIES

Husky has been involved in the gathering, transporting and storage of heavy crude oil in the Lloydminster area since the early 1960s. Husky's crude oil pipeline systems include approximately 1,900 kilometres of pipeline and are capable of transporting in excess of 528 mbbls/day of blended heavy crude oil, diluent and synthetic crude oil. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through the Husky Lloydminster Upgrader and Husky's asphalt refinery in Lloydminster. Blended heavy crude oil and synthetic crude oil from the upgrading operations are moved south to Hardisty, Alberta to a connection to the Enbridge Pipeline system and the Express Pipeline system. The crude oil is transported to eastern and southern markets on these pipelines. Husky's crude oil pipeline systems also have feeder pipeline interconnections with the Cold Lake Partnership Pipeline the Enbridge Athabasca Pipeline and the Talisman Chauvin Pipeline.

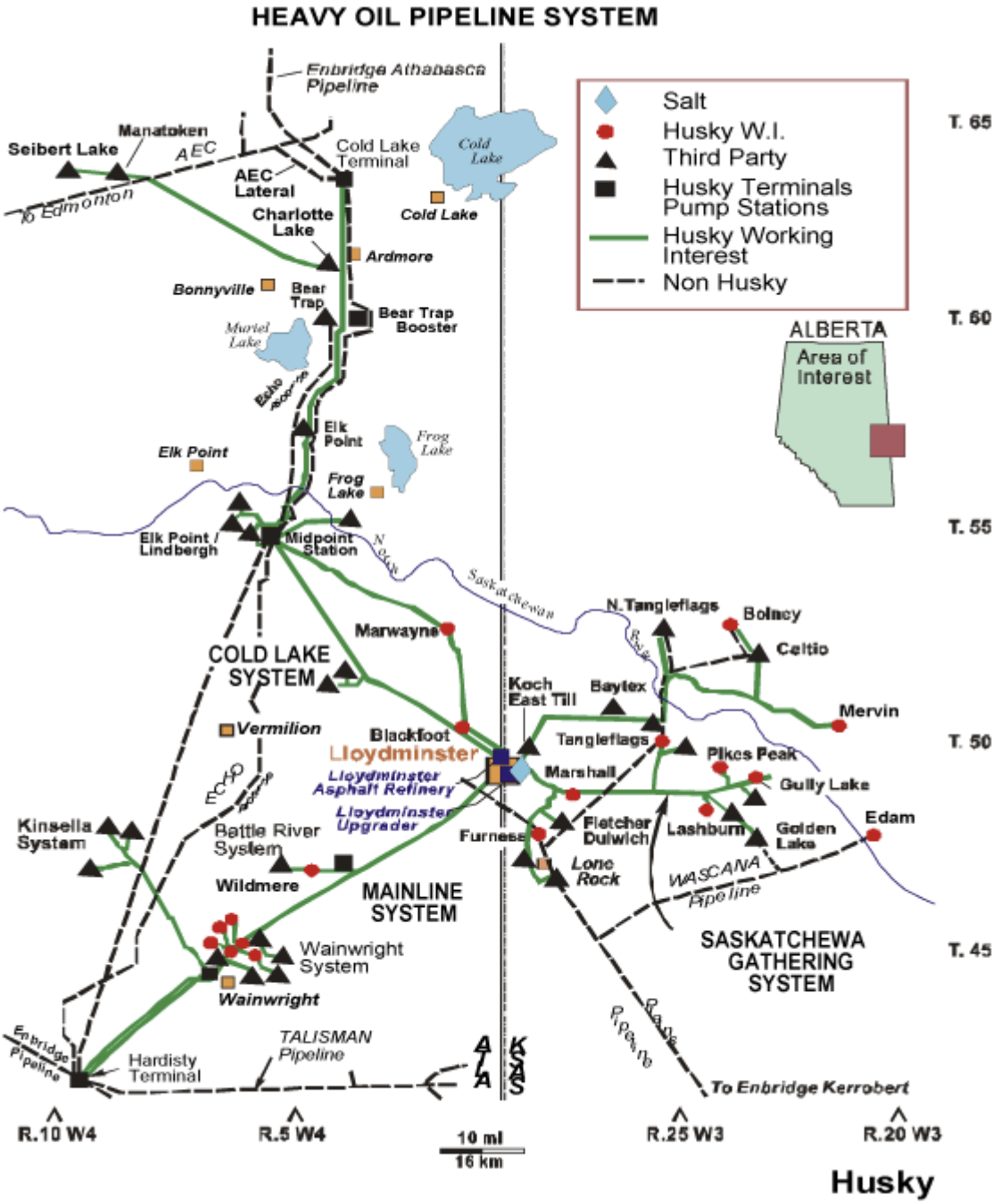
The following table shows the average daily pipeline throughput for the periods indicated:

	Years ended December 31,		
	2002	**2001**	**2000**
		(mbbls/day)	
Combined pipeline throughput	457	537	528

In recent years Husky has expanded and expects to further expand its heavy crude pipeline systems to capitalize on anticipated increases in heavy oil production from the Lloydminster and Cold Lake areas. Husky considers the expansion and optimization of its pipeline systems in the

Lloydminster area to be necessary to further its own development objectives in the area. As a result of recent expansion of mainline pipeline systems in the area, competition for throughput volumes has increased.

Husky operates 16 heavy crude oil processing facilities located throughout the Lloydminster area. These facilities process Husky's and other producers' raw heavy crude oil from the field by removing sand, water and other impurities to produce clean dry heavy crude oil. The heavy crude oil is then blended with a diluent to meet pipeline specifications for transportation.



COGENERATION

Husky has a 50% interest in a 215 MW natural gas fired cogeneration facility at the site of the Husky Lloydminster Upgrader. The plant was commissioned in December 1999. Electricity produced at the facility is being sold to Saskatchewan Power Corporation under a 25 year power purchase agreement. Thermal energy (steam) is sold to the Husky Lloydminster Upgrader.

Husky has a 50% interest in a 90 MW natural gas fired cogeneration facility adjacent to Husky's Rainbow Lake processing plant. The cogeneration plant produces electricity for the Alberta Power Pool and thermal energy (steam) for the Rainbow Lake processing plant. It provides power directly to the Alberta Power Pool and is the result of an agreement with the Alberta Transmission Administrator to provide additional electricity generating capacity and system stability for north-western Alberta. The power plant has the capability of being expanded to approximately 110 MW in total. Husky is the operator of the facility.

NATURAL GAS STORAGE FACILITIES

Husky has been operating a natural gas storage facility at Hussar, Alberta since April 2000. The facility has a working storage capacity of 17 bcf of natural gas. Husky is continuing to evaluate additional storage opportunities within Western Canada. Western Canada and Alberta in particular, may prove to be a potential key storage hub for arctic gas development.

MARKETING

Husky is a marketer of both its own and third party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. Husky also markets petroleum coke, a by-product from the Lloydminster upgrader. Husky supplies feedstock to its upgrader and asphalt refinery from its own and third party heavy oil production sourced from the Lloydminster and Cold Lake areas. Husky also sells blended heavy crude oil directly to refiners based in the United States and Canada. Husky's extensive infrastructure in the Lloydminster area supports its heavy crude oil refining and marketing operations.

Husky markets light and medium crude oil and NGL sourced from its own production and third party production. Light crude oil is acquired for processing by third party refiners at Edmonton, Alberta and by the Company's refinery at Prince George, British Columbia. Husky markets the synthetic crude oil produced at its upgrader in Lloydminster to refiners in Canada and the United States.

Husky markets natural gas sourced from its own production and third party production. Husky is currently committed to contracts with third parties, which in aggregate do not exceed amounts forecast to be deliverable from Husky's reserves. Husky's contracts are with customers located in eastern Canada/north-eastern United States (27%), mid-west United States (34%), Western Canada (30%) and west coast United States (9%). The natural gas volumes contracted are primarily at market price (92%). The terms of the contracts are up to one year (50%), one year to five years (15%) and over five years (35%). Husky has acquired rights to firm pipeline capacity to transport the natural gas to most of these markets.

The oil and gas product marketing component of Husky's business has experienced strong growth since the early 1990s. Husky has developed its marketing operations to include the acquisition of third party volumes in order to increase growing internal natural gas demand, increase volumes and enhance the value of its midstream assets. Husky plans to expand its marketing operations by continuing to increase marketing activities. Husky believes that this increase will generate synergies with the marketing of its own production volumes and the optimization of its assets.

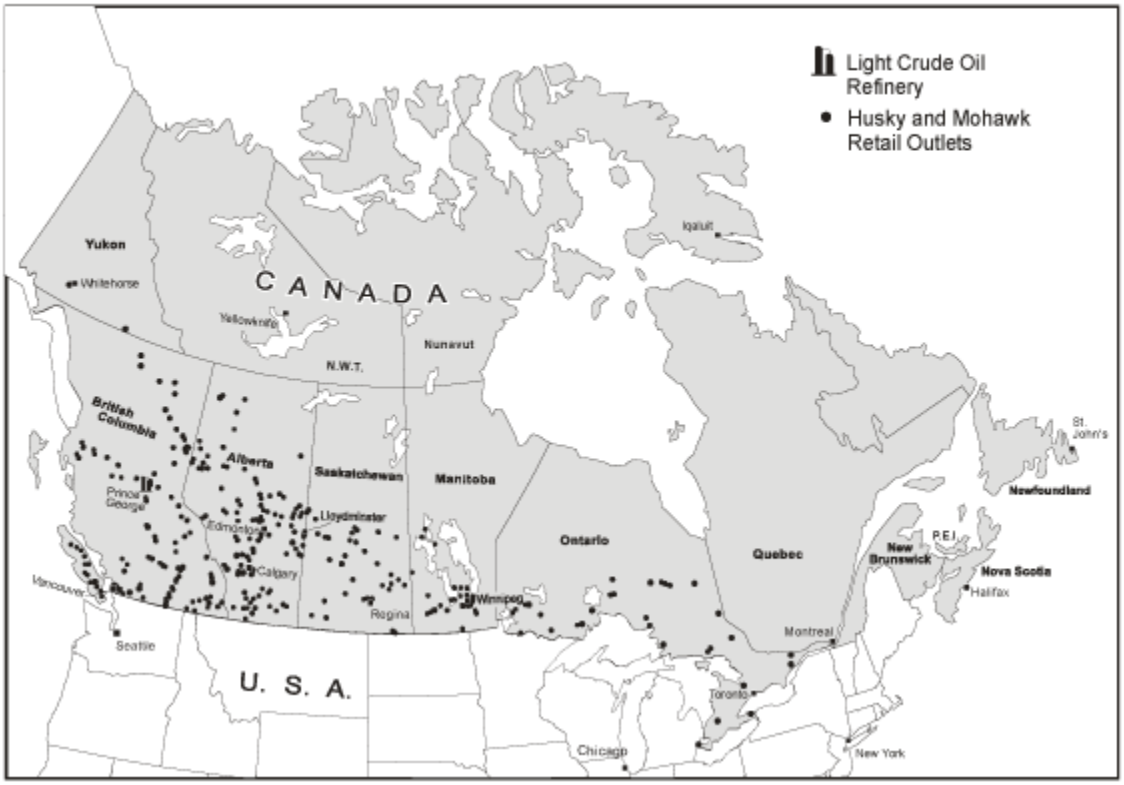
Refined Products

Overview

Husky's refined products operations include refining and retail, commercial and wholesale marketing of refined petroleum products. This network provides a platform for substantial non-fuel related businesses.

Light oil refined products are produced at Husky's refinery at Prince George, British Columbia and are also acquired from other third party refiners and marketed through Husky and Mohawk branded retail and commercial petroleum outlets and through direct marketing to third party dealers and end users. Asphalt and residual products are produced at Husky's asphalt refinery at Lloydminster, Alberta and marketed directly or through Husky's 10 terminals located throughout Western Canada.

Branded Petroleum Outlets



Branded Petroleum Outlets and Commercial Distribution

DISTRIBUTION

As of December 31, 2002, there were 571 independently operated Husky and Mohawk branded petroleum outlets, including service stations, truck stops and bulk distribution facilities located from Vancouver Island on the west coast of Canada to the eastern border of Ontario. The truck stop network is strategically located on major highways and serves the retail market and commercial transporters 24 hours per day, 365 days per year with quality products and full service Husky House restaurants. At most locations, the truck stop network also features the proprietary "Route Commander" cardlock system that enables commercial users to purchase

products using a card system that will electronically process transactions and provide detailed billing, sales tax and other information. A variety of full and self serve retail locations under the Mohawk and Husky brand names serve urban and rural markets, while Husky and Mohawk bulk distributors offer direct sales to commercial and farm markets in Western Canada.

Independent retailers or agents operate all Husky and Mohawk branded outlets. Branded outlets feature varying services such as 24 hour service, convenience stores, service bays, car washes, Husky House full service family style restaurants, proprietary and co-branded quick serve restaurants, bank machines and alternate fuels such as propane and compressed natural gas. In addition to conventional gasolines, ethanol blended fuels branded as "Mother Nature's" gasoline and additive enhanced "Diesel Max" are offered in selected markets together with Chevron and Mohawk lubricants. Husky supplies refined petroleum products to its branded independent retailers on an exclusive basis and also provides financial and other assistance for location improvements, marketing support and related services. Husky's brands are promoted through various national and university athletic sponsorships as well as advertising designed to reach both national and regional audiences.

The following table shows the number of Husky and Mohawk branded petroleum outlets by class of trade and by province as of December 31, 2002.

Branded Petroleum Outlets	British Columbia & Yukon	Alberta	Saskatchewan	Manitoba	Ontario	Total
Truck Stops	7	5	5	2	17	36
Travel Stops	2	3			2	7
Full Serve	60	71	21	31	7	190
Full/Self Serve	62	58	7	19	10	156
Self Serve	63	74	11	6	3	157
Bulk Distributor	5	13	5	1	1	25
	199	224	49	59	40	571
Cardlocks[(1)]	18	14	6	4	20	62
Convenience Stores[(1)]	152	177	50	48	11	438
Restaurants[(2)]	10	9	6	2	18	45

Notes:

(1) All of these are located at a branded petroleum outlet.

(2) One Husky House restaurant in Calgary, Alberta is not located at a petroleum outlet.

Husky also markets refined petroleum products directly to various commercial markets, including independent dealers, national rail companies and major industrial and commercial customers in Western Canada and the north-western United States.

The following table shows Husky's average daily sales volumes of light refined petroleum products for the periods indicated:

	Years ended December 31,		
	2002	2001	2000
		(mbbls/day)	
Gasoline	26.3	25.4	24.9
Diesel fuel	20.7	21.1	20.3
Liquefied petroleum gas	1.3	1.3	1.6
	48.3	47.8	46.8

Husky's current strategy in respect of its petroleum product outlets includes continuing to increase profits and sales through the strategic location of new outlets, the enhancement of ancillary non-fuel income streams, the modernization, automation and upgrading of existing petroleum product outlets, expanding customer loyalty programs and the sale of non-core locations. Husky also plans to continue to enter into strategic alliances with third parties to sell various consumer products at Husky and Mohawk branded petroleum outlets in order to generate revenue and increase demand for other products and services provided at those outlets. Husky is pursuing acquisitions and joint venture opportunities to further enhance its existing distribution network.

SUPPLY

Prince George Refinery. Husky owns and operates a refinery at Prince George, British Columbia, which has capacity to refine more than 10,000 bbls/day of light crude oil into a full range of refined petroleum products. The crude oil feedstock for the Prince George refinery is produced primarily in north-eastern British Columbia by other producers and delivered to Husky's refinery by pipeline. Husky is pursuing acquisitions and joint venture opportunities to further enhance its existing refining capacity.

Other Supply Arrangements. In addition to the refined petroleum products supplied by the Prince George refinery, Husky has established processing arrangements with other refiners. Processing arrangements allow Husky to participate in industry refining margins. Primarily Husky production and some third party purchased crude oil is delivered to refiners, who process the crude oil into refined products, which are then marketed by Husky in its retail networks and to its wholesale customers. During 2002, these refiners processed an average of approximately 30.9 mbbls/day of crude oil for Husky, yielding approximately 27.8 mbbls/day of refined petroleum products. During 2002, Husky also purchased approximately 9.6 mbbls/day of refined petroleum products from refiners and acquired approximately 6.5 mbbls/day of refined petroleum products pursuant to exchange agreements with third party refiners.

Minnedosa, Manitoba — Ethanol Plant. Husky owns an ethanol plant at Minnedosa, Manitoba that produces 10 million litres per year. Ethanol is an oxygenate derived from biomass, which, when added to gasoline, promotes fuel combustion, raises octane levels and inhibits water from freezing in fuel lines. The ethanol blended gasoline (Mother Nature's Fuel) has received federal government recognition for its low combustion emissions. Husky is actively repositioning its supply of ethanol as ethanol-blended gasoline is now available at all Husky and Mohawk outlets.

Asphalt Products

Husky has been in the paving and specialty asphalt business for over 50 years. Husky supplies asphalt products to customers across Western Canada and the north-western and midwestern United States. Husky has a significant market share for paving asphalt, emulsified asphalt and asphalt products sold in Western Canada. Most of the asphalt sold is used for paving and other industrial purposes. Husky's Pounder Emulsions division manufactures modified and conventional road application emulsion products. Additional non-asphalt based road maintenance products are marketed and distributed through the Western Road Management division of Husky. Demand for higher quality asphalt products has allowed Husky to increase sales into the United States and Eastern Canada, with products occasionally being shipped as far away as Texas, Florida and New Brunswick. In 2002, 49 percent of Husky's asphalt production was exported to the United States. Husky plans to continue its efforts to improve its asphalt business by increasing its modified asphalt production capacity to produce better products at a lower cost. Husky is also studying the feasibility of expanding its production and distribution capacity.

Husky's asphalt distribution network consists of nine emulsion plants and terminals located at Kamloops and Prince George, British Columbia; Watson Lake, Yukon; Edmonton and Lethbridge, Alberta; Lloydminster, Saskatoon and Yorkton, Saskatchewan; and Winnipeg, Manitoba. Husky also utilizes independent terminals at Langley, British Columbia.

All of Husky's asphalt requirements are supplied by its Lloydminster, Alberta asphalt refinery. The refinery was commissioned in 1983, replacing a Husky facility that had been operating since 1947. The refinery was designed specifically to produce asphalt from heavy crude oil at a rate of 25 mbbls/day. The crude oil feedstock for the Lloydminster refinery is supplied through Husky's pipeline systems from the supply of heavy crude oil in the region, including Husky's heavy crude oil.

The following table shows the average daily sales volumes of products produced at the Lloydminster refinery, for the years indicated:

	Years ended December 31,		
	2002	**2001**	**2000**
		(mbbls/day)	
Asphalt	12.7	12.6	12.0
Residual and other	8.1	8.8	8.2
	20.8	21.4	20.2

Refinery throughput averaged 22.0 mbbls/day of blended heavy crude oil feedstock during 2002. Diluent included in the feedstock, extracted and returned to the field averaged 2.6 mbbls/day in 2002. Due to the seasonal demand for asphalt products the refinery historically has operated at full capacity only during the normal paving season in Canada and the northern United States. Husky has implemented various plans to increase refinery throughput during the other months of the year, such as producing low sulphur diesel, entering into custom processing arrangements and developing other U.S. and international markets for asphalt products.

HUMAN RESOURCES

The number of employees in each business segment was as follows:

Business Segment	Number of Employees at December 31, 2002	2001
Upstream	1,560	1,451
Midstream	344	314
Refined Products	329	332
Corporate and business support	520	501
	2,753	2,598

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following table sets out financial information with respect to Husky for the periods indicated. This information should be read in conjunction with the Consolidated Financial Statements of Husky which are contained in its 2002 Annual Report.

	Years ended December 31,		
	2002	2001	2000
		($millions except per share data)	
Statement of Earnings Data Sales and operating revenues	$ 6,384	$6,596	$5,066
Cash flow from operations	2,096	1,946	1,399
Net Earnings (loss)	804	654	438
Per share — Basic	1.88	1.49	1.28
Per share — Diluted	1.88	1.48	1.28
Balance Sheet Data			
Total assets	10,575	9,370	8,829
Shareholders' equity	5,127	4,486	3,985
Total long term debt	1,964	1,948	2,311
Dividend per share	$ 0.09[1]	$ 0.09[1]	0.09[2]

Notes:

(1) Declared and paid in respect of each quarter in 2002 and 2001.

(2) Dividend in respect of the fourth quarter of 2000 declared on February 14, 2001 and paid on April 1, 2001.

There were no changes in accounting policies, major acquisitions or divestitures, or major changes in the nature of Husky's business that affect the comparability of this annual data, except for (i) the adoption of the recommendations of the Canadian Institute of Chartered Accountants with respect to accounting for foreign exchange effective January 1, 2002, (ii) the adoption of the recommendations of the Canadian Institute of Chartered Accountants with respect to accounting for income taxes effective January 1, 1999; (iii) the acquisition of Renaissance; and (iv) the adoption of the recommendations of the Canadian Institute of Chartered Accountants in respect of the calculation and presentation of earnings per share. Description of these changes are contained

in Notes 3(f), 10, 6 and 11, respectively, to the Consolidated Financial Statements of Husky which are contained in Husky's 2002 Annual Report and are incorporated herein by reference.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's discussion and analysis of financial condition and results of operations for the fiscal years ended December 31, 2002 and December 31, 2001 is contained on pages 32 through 58 of Husky's 2002 Annual Report and is incorporated herein by reference.

MARKET FOR SECURITIES

Husky's common shares are listed and posted for trading on the Toronto Stock Exchange under the trading symbol "HSE".

DIRECTORS AND OFFICERS

The following are the names and municipalities of residence of the directors and officers of Husky, their positions and offices with Husky and their principal occupations during the past five years. The directors shall hold office until the next annual meeting of Husky shareholders or until their respective successors have been duly elected or appointed.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
Li, Victor T.K. Hong Kong	Co-Chairman and Director	Managing Director of Cheung Kong (Holdings) Limited (an investment holding company) since 1999 and Deputy Chairman since 1994. Mr. Li has also been Deputy Chairman of Hutchison Whampoa Limited (an investment holding company) since 1999 and Executive Director since 1995, as well as Chairman of Cheung Kong Infrastructure Holdings Limited (an infrastructure development company) since 1996 and of CK Life Sciences Int'l., (Holdings) Inc. (a biotechnology company) since 2002. Mr. Li is also an Executive Director of Hongkong Electric Holdings Limited (a holding company) and a Director of The Hong Kong and Shanghai Banking Corporation Limited. Mr. Li is a member of the Chinese People's Political Consultative Conference of the People's Republic of China and he is also a member of the Commission on Strategic Development and the Business Advisory Group of the Hong Kong Special Administrative Region. Mr. Li holds a Bachelor of Science degree in Civil Engineering and a Master of Science degree in Structural Engineering.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
Fok, Canning K.N. Hong Kong	Co-Chairman and Director	Group Managing Director of Hutchison Whampoa Limited since 1993 and Executive Director since 1984. Mr. Fok is the Chairman of Hutchison Telecommunications (Australia) Limited (a telecommunications company) since 1999, Hutchison Harbour Ring Limited (an investment holding company) since 2002 and Partner Communications Company Ltd. (a telecommunications company) since 1998 and the Deputy Chairman of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited. Mr. Fok is also a director of Cheung Kong (Holdings) Limited and Hutchison Whampoa Finance (CI) Limited (a finance company). Mr. Fok holds a Bachelor of Arts degree and is a member of the Australian Institute of Chartered Accountants.
Glynn, Martin J.G. Vancouver, British Columbia	Director	President, Chief Executive Officer and a director of HSBC Bank Canada since late 1999 and Chief Operating Officer from 1997 to 1999. From 1982 Mr. Glynn held various senior executive positions with HSBC Bank Canada (formerly Hongkong Bank of Canada). Mr. Glynn has been a Director and Chief Operating Officer of HSBC North America Inc. since 2002, and a Director of HSBC Bank USA and Chairman and director of HSBC Canadian Direct Insurance Incorporated. Mr. Glynn is also a director of Wells Fargo HSBC Trade Bank N.A. in the United States. Mr. Glynn is also a member of the Board of Governors for the University of British Columbia.
Greene, Ronald G.[1] Calgary, Alberta	Director	President and Chief Executive Officer of Tortuga Investment Corp. (an investment holding company), Chairman of Denbury Resources Inc. and a Director of WestJet Airlines Ltd. Mr. Greene was the founder and Chairman of Renaissance Energy Ltd. until its merger with Husky Oil Limited in 2000.
Hui, Terence C.Y. Vancouver, British Columbia	Director	President & Chief Executive Officer, Concord Pacific Group Inc. (a real estate development company) since 1997, President of Adex Securities Inc. (a financial services company) since 1992 and Chairman of Maximizer Software Inc. (formerly Multiactive Software Inc.) (a computer software company) since 1995. Mr. Hui was President and Chief Executive Officer of Pacific Place Developments Corp. (a real estate development company) from 1992 to 2001.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
Kinney, Brent D. Dubai, United Arab Emirates	Director	Independent businessman. Mr. Kinney is a director of Dragon Oil plc in the United Arab Emirates.
Kluge, Holger Toronto, Ontario	Director	Corporate Director. Mr. Kluge was President, Personal and Commercial Bank, Canadian Imperial Bank of Commerce from 1990 to 1999 and a director from 1992 to 1999. Mr. Kluge is a director of Hongkong Electric Holdings Limited, Hutchison Telecommunications (Australia) Limited, TOM.COM LIMITED and Assante Corp. (a financial planning company). Mr. Kluge holds a Bachelor of Commerce degree and a Master's degree in Business Administration.
Koh, Poh Chan Hong Kong	Director	Finance Director, Harbour Plaza Hotel Management (International) Ltd. Miss Koh was Executive Vice President and Chief Financial Officer of Husky Oil Ltd. from 1992 to 1997.
Kwok, Eva L. Vancouver, British Columbia	Director	Chairman, a director and Chief Executive Officer, Amara International Investment Corp. (an investment holding company) since 1992 and President from 1992 to 1996. Mrs. Kwok is a director of Air Canada, Bank of Montreal Group of Companies and Telesystem International Wireless Inc. and since 2002 of CK Life Sciences Int'l., (Holdings) Inc. (a biotechnology company).
Kwok, Stanley T.L. Vancouver, British Columbia	Director	President, Stanley Kwok Consultants (an architecture and development company) since 1993. Mr. Kwok has been a director since 1997, and was Chairman from 1996 to 1998 of Amara International Investment Corp. Mr. Kwok is a director of Cheung Kong (Holdings) Limited and CTC Bank of Canada.
Lau, John C.S. Calgary, Alberta	President & Chief Executive Officer and Director	President & Chief Executive Officer of Husky Energy Inc. since August 2000. Prior thereto, Mr. Lau was Chief Executive Officer of Husky Oil Limited since 1993.
Matthews, Wilmot L.[1] Toronto, Ontario	Director	Mr. Matthews has been involved in all aspects of investment banking by serving in various positions with Nesbitt Burns Inc. and its predecessor companies from 1964 until his retirement in 1996, most recently as Vice Chairman and Director. Mr. Matthews is currently President of Marjad Inc. (a personal investment company). Mr. Matthews is Chairman and Chief Executive Officer of Helptrain Inc. (a sales, marketing, E-learning and E-business process company) and a Director of WestJet Airlines Ltd.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
Shaw, Wayne E. Toronto, Ontario	Director	Barrister and Solicitor, Stikeman Elliott LLP.
Shurniak, William Australia	Deputy Chairman and Director	Director and Chairman of ETSA Utilities (a utility company) since 2000, Powercor Australia Limited (a utility company) since 2000 and CitiPower Pty Ltd. (a utility company) since 2001. Mr. Shurniak has also been a director of Envestra Limited (a natural gas distributor) since 2000 and Downer Edi Ltd. (an engineering services company) since 2001. Mr. Shurniak was an Executive Director and Group Finance Director of Hutchison Whampoa Limited from 1984 to 1997 and has remained a director of Hutchison Whampoa Limited since then. Mr. Shurniak was a director and Deputy Chairman of Asia Satellite Telecommunications Holdings Limited (a telecommunications company) from 1996 to 1999. Mr. Shurniak holds an Honorary Doctor of Laws degree from the University of Saskatchewan and from The University of Western Ontario.
Sixt, Frank J. Hong Kong	Director	Group Finance Director of Hutchison Whampoa Limited since 1998 and Executive Director since 1991. Mr. Sixt is the Chairman of TOM.COM LIMITED since 1999. Mr. Sixt is also an Executive Director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited and a director of Cheung Kong (Holdings) Limited, Hutchison Whampoa Finance (CI) Limited, Hutchison Telecommunications (Australia) Limited and Partner Communications Company Ltd. Mr. Sixt was also a director of Orange plc. from 1998 to 2000 and of Voice Stream Wireless Corp. from 2000 to 2001. Mr. Sixt holds a Master's degree in Arts and a Bachelor's degree in Civil Law and is a member of the Bar and of the Law Society of the Provinces of Quebec and Ontario, Canada.
McGee, Neil D. Calgary, Alberta	Vice President & Chief Financial Officer	Vice President & Chief Financial Officer of Husky since August 2000. Prior thereto Mr. McGee was Vice President and Chief Financial Officer of Husky Oil Limited since 1998. Prior to joining Husky Oil Limited Mr. McGee was with Hutchison Whampoa Limited first as group legal advisor and Corporate Secretary and then as Senior Manager of Corporate Finance and Corporate Secretary.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
Ingram, Donald R. Calgary, Alberta	Senior Vice President, Midstream & Refined Products	Senior Vice President, Midstream and Refined Products of Husky since August 2000. Prior thereto Mr. Ingram was Vice President, Downstream of Husky Oil Limited from 1994 until 1999 when he became Vice President of Midstream of Husky Oil Limited.
Girgulis, James D. Calgary, Alberta	Vice President, Legal & Corporate Secretary	Vice President, Legal & Corporate Secretary of Husky since August 2000. Mr. Girgulis joined Husky Oil Limited in 1994 as part of the legal group and became General Counsel and Corporate Secretary in 1999.

Note:

(1) Will not be standing for re-election at the annual meeting on April 30, 2003.

The board of directors has an Audit Committee (as required by the *Business Corporations Act* (Alberta)) currently consisting of M.J.G. Glynn, T. C.Y. Hui, W.L. Matthews and W.E. Shaw, and a Compensation Committee currently consisting of C.K.N. Fok, R.G. Greene, H. Kluge, E.L. Kwok and F.J. Sixt, and a Health, Safety and Environment Committee currently consisting of B.D. Kinney, H. Kluge and S.T.L. Kwok and a Corporate Governance Committee currently consisting of H. Kluge, E.L. Kwok and W.L. Matthews. Husky does not have an Executive Committee. As Messrs. Greene and Matthews are not standing for re-election as directors at the 2003 annual shareholders' meeting their term on the committees which they are currently members will end on the date of that meeting.

As at February 28, 2003, the directors and officers of Husky, as a group, owned beneficially, directly or indirectly, or exercised control or direction over 1,609,865 common shares of Husky representing less than 1% of the issued and outstanding common shares.

Conflicts of Interest

Certain officers and directors of Husky are also officers and/or directors of other companies engaged in the oil and gas business generally and which, in certain cases, own interests in oil and gas properties in which Husky holds or may in future hold an interest. As a result, situations arise where the interests of such directors and officers conflict with their interests as directors and officers of other companies. In the case of the directors the resolution of such conflicts is governed by applicable corporate laws which require that directors act honestly, in good faith and with a view to the best interests of Husky and, in respect of the *Business Corporations Act* (Alberta), Husky's governing statute, that directors declare, and refrain from voting on, any matter in which a director may have a conflict of interest.

Corporate Cease Trade Order or Bankruptcies

None of those persons who are directors, officers or promoters of the Corporation is, or has been within the past ten years, a director, officer or promoter of any other corporation that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the access to any statutory exemptions for a period of more than 30 consecutive days, or was declared bankrupt or made a voluntary assignment in bankruptcy, made a proposal under

any legislation relating to bankruptcy or insolvency or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of that person.

Penalties or Sanctions

None of the persons who are directors, officers or promoters of the Corporation have, within the ten years prior to the date of this Annual Information Form, been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded corporation, or theft or fraud.

DIVIDEND POLICY

The board of directors of Husky have established a dividend policy that pays quarterly dividends. Since August 2000, the Corporation has paid a quarterly dividend of $0.09 ($0.36 annually) per common share. However, there can be no assurance that further dividends will be declared. The declaration and payment of dividends will be at the discretion of the board of directors of Husky which will consider earnings, capital requirements, financial condition of Husky and other relevant factors.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and options to purchase common shares, and interests of insiders in material transactions is contained in Husky's Management Information Circular dated March 26, 2003 (the "Information Circular"), prepared in connection with the Annual Meeting of shareholders to be held on April 30, 2003.

Additional financial information is provided in Husky's Consolidated Financial Statements and Management's Discussion and Analysis for the most recently completed fiscal year ended December 31, 2002, contained in Husky's 2002 Annual Report.

Copies of the Information Circular, the financial statements, including any interim financial statements, additional copies of this Annual Information Form, including one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form, and if Husky is in the course of a distribution pursuant to a short-form prospectus or a preliminary short-form prospectus, any other documents incorporated therein by reference may be obtained upon request from the Vice President, Legal & Corporate Secretary of Husky, 40th Floor, 707 8th Avenue S.W., Calgary, Alberta T2P 1H5, Telephone: (403) 298-7333; Facsimile: (403) 298-7323.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intends," "plans," "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors

discussed throughout this Annual Information Form. Among the key factors that have a direct bearing on the Company's results of operation are the nature of the Company's involvement in the business of exploration, development and production of oil and natural gas reserves and the fluctuation of the exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under "Management's Discussion and Analysis of Financial Condition and Results of Operations", incorporated by reference from the Company's 2002 Annual Report and elsewhere in this Annual Information Form.

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

Exhibit 3

HUSKY ENERGY INC.

2002
Management's Discussion and Analysis

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements and Auditors' Report included in this Annual Report. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada. The effect of significant differences between Canadian and United States accounting principles is disclosed in note 16 of the Consolidated Financial Statements. The following discussion and analysis refers primarily to 2002 compared with 2001, unless otherwise indicated. An abridged discussion and analysis of the salient variances between 2001 and 2000 is provided on page 23. 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 of gas equivalent ("mcfge") are based on a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. All production volumes quoted are gross, the Company's working interest share before royalties, and realized prices include the effect of hedging gains and losses, unless otherwise indicated.

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

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer (its principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of a date within 90 days prior to the filing of this Annual Report (the "evaluation date"), that the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Security and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes to Internal Controls and Procedures for Financial Reporting

There have been no significant changes to Husky's internal controls or in other factors that could significantly affect these controls subsequent to the evaluation date and the filing date of this Annual Report.

Forward-Looking Statements

Certain of the statements set forth under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report 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 and are based upon Husky's current belief as to the outcome and timing of such future events. There are numerous risks and uncertainties that can affect the outcome and timing of such events, including many factors beyond the control of Husky. These factors include, but are not limited to, the matters described under the heading "Business Environment". Should one or more of these risks or uncertainties occur, or should any of the underlying assumptions prove incorrect, Husky's actual results and plans for 2003 and beyond could differ materially from those expressed in the forward-looking statements.

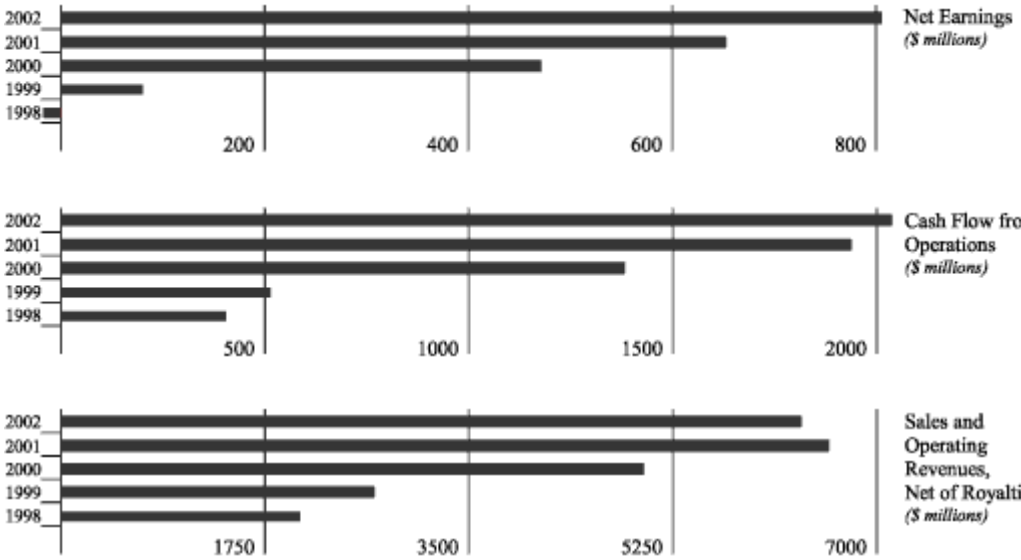
Overview

Husky's operations are organized into three major business segments:

- The upstream segment includes the exploration for and the development and production of crude oil and natural gas in Western Canada, offshore the Canadian East Coast and offshore Southern China and other international areas.
- The midstream segment is organized into two reportable business segments; heavy crude oil upgrading operations, and infrastructure and commodity marketing operations. The infrastructure and commodity marketing segment comprises heavy crude oil pipeline and processing operations, natural gas storage, cogeneration operations and crude oil and natural gas marketing.
- The refined products segment consists of refining of crude oil and marketing of refined petroleum products including asphalt products.

Year ended December 31 ($ millions, except per share amounts and production)	2002	% Change	2001[1]	% Change	2000[1]
Net earnings	$ 804	23	$ 654	49	$ 438
Per share — Basic	1.88	26	1.49	16	1.28
— Diluted	1.88	27	1.48	16	1.28
Cash flow from operations	2,096	8	1,946	39	1,399
Per share — Basic	4.94	7	4.60	8	4.26
— Diluted	4.92	8	4.57	7	4.26
Sales and operating revenues, net of royalties	6,384	(3)	6,596	30	5,066
Daily production, before royalties					
Light/medium crude oil & NGL *(mbbls/day)*	125.9	12	112.0	76	63.6
Lloydminster heavy crude oil *(mbbls/day)*	79.4	21	65.4	22	53.5
Natural gas *(mmcf/day)*	569.2	(1)	572.6	60	358.0
Barrels of oil equivalent (6:1) *(mboe/day)*	300.2	10	272.8	54	176.8

(1) 2001 and 2000 amounts as restated. Refer to note 3 of the Consolidated Financial Statements.



Consolidated Results Summary

Total consolidated revenue during 2002 was three percent lower than in 2001 primarily as a result of lower natural gas prices. The effect of lower natural gas prices was most noticeable in the infrastructure and marketing segment with respect to natural gas marketing revenues.

Higher net earnings and cash flow in 2002 compared with 2001 were attributable to increased earnings from:

- the upstream business segment
- the commodity marketing and infrastructure business segment

partially offset by lower earnings from:

- the upgrading business segment
- the refined products business segment

Upstream

Earnings from the upstream segment increased by $206 million to $688 million in 2002 compared with $482 million in 2001 due to:

- higher realized oil prices

- higher crude oil production
- lower natural gas royalties

partially offset by:

- lower prices for natural gas
- higher operating costs

Midstream

Earnings from the midstream segment decreased by $95 million to $161 million in 2002 compared with $256 million in 2001 due to:

- narrower upgrading differentials
- lower pipeline throughput

partially offset by:

- higher oil and gas commodity marketing income
- higher cogeneration income
- lower energy related upgrading operating costs

Refined Products

Earnings from the refined products segment decreased by $31 million to $32 million in 2002 compared with $63 million in 2001 due to:

- lower margins on asphalt sales

partially offset by:

- improved gasoline and distillate margins

Corporate

Corporate charges decreased by $70 million to $77 million in 2002 from $147 million in 2001, due to:

- lower foreign exchange losses on translation of U.S. dollar denominated long-term debt

partially offset by:

- higher intersegment profit eliminations
- higher corporate asset depreciation
- higher net interest expense

Business Environment

Husky's financial results are significantly influenced by its business environment, in particular, by crude oil and natural gas prices, the costs to find, develop, produce and deliver crude oil and natural gas, the demand for and ability to deliver natural gas, the exchange rate between the Canadian dollar and the U.S. dollar, refined product margins, the demand for Husky's pipeline capacity, the demand for refined petroleum products, government regulation and the cost of borrowing.

Average Benchmark Prices

	2002	2001	2000
West Texas Intermediate ("WTI") *(U.S. $/bbl)*	$ 26.08	$ 25.97	$ 30.20
NYMEX natural gas *(U.S. $/mmbtu)*	$ 3.25	$ 4.38	$ 3.91
AECO natural gas *($/GJ)*	$ 3.86	$ 5.97	$ 4.76
WTI/Lloyd blend differential *(U.S. $/bbl)*	$ 6.47	$ 10.74	$ 8.20
U.S./Canadian dollar exchange rate *(U.S. $)*	$ 0.637	$ 0.646	$ 0.673

Commodity Prices

Husky's earnings depend largely on the profitability of its upstream business, which is significantly affected by fluctuations of oil and gas prices. Commodity prices have been, and are expected to be, volatile due to a number of factors beyond Husky's control. The prices received for the crude oil and NGL sold by Husky are related to the price of crude oil in world markets. Prices for heavy crude oil and other lesser quality crudes trade at a discount or differential to light sweet crude oil.

Average benchmark oil prices were marginally higher during 2002 after rising throughout most of the year. The price for West Texas Intermediate ("WTI") crude oil began the year at U.S. $21.13/bbl and ended at U.S. $31.21/bbl, averaging U.S. $26.08/bbl for the year, slightly higher than U.S. $25.97/bbl in 2001 and significantly less than the U.S. $30.20/bbl in 2000.

The opposite trend occurred for average heavy crude oil differentials, which averaged U.S. $6.47/bbl for WTI/Lloyd blend during 2002 compared with U.S. $10.74/bbl during 2001. The narrower differential tends to improve Husky's financial results as the Company's crude oil production is weighted toward heavier gravity crudes. In periods of wider differentials, Husky's upgrader offsets some of the effect of lower heavy crude prices. Husky's realized price for light/medium crude oil and NGL averaged $33.28/bbl in 2002 compared with $27.19/bbl in 2001 and heavy crude oil averaged $26.09/bbl in 2002 compared with $15.85/bbl in 2001.

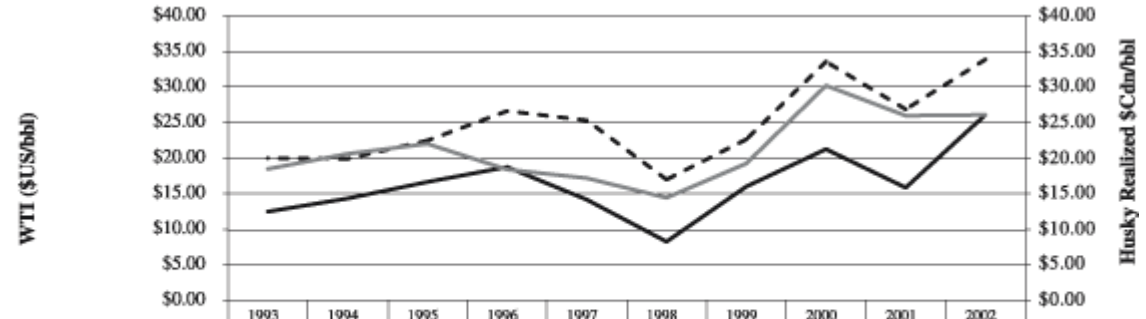
Toward the end of 2002 the Organization of Petroleum Exporting Countries ("OPEC") announced cuts to their production that were intended to keep prices within a U.S. $22 and $28/bbl price band. OPEC has maintained their production discipline for the past three years and prices have fluctuated within the price

band. World crude oil prices increased toward the end of 2002 and into 2003 as a result of a number of events in addition to OPEC's decision to cut actual production: colder than normal temperatures; uncertainty over the near-term in respect of Iraq; and, the crippling oil industry strikes in Venezuela. On February 11, 2003 WTI was U.S. $35.43/bbl.

The price of natural gas is affected by regional supply and demand factors in North America, particularly those affecting in the United States such as weather patterns, pipeline delivery capacity, the availability of alternative sources of less costly energy supply, inventory levels and general industry activity levels. Periodic imbalances between supply and demand for natural gas are common and result in volatile pricing. The price of natural gas, unlike crude oil, is not subject to the influence of an organization like OPEC.

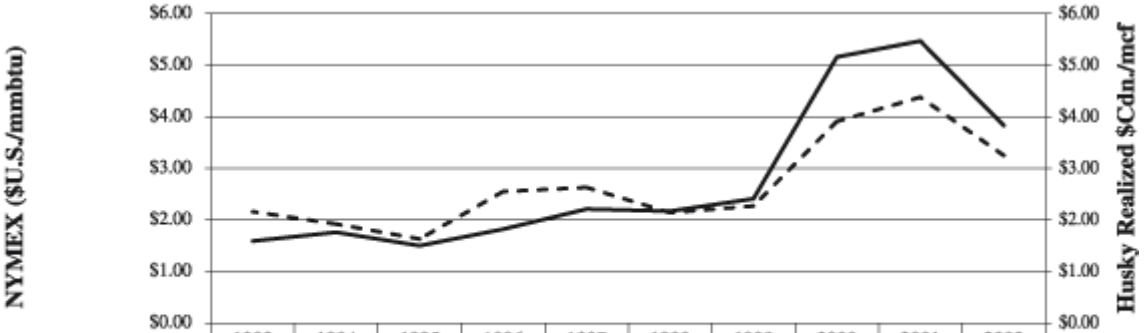
Natural gas prices realized by Husky are based either on fixed price contracts, spot prices or the New York Mercantile Exchange ("NYMEX") or other United States or domestic regional market prices. The NYMEX near-month price for natural gas ended 2002 at U.S. $4.79/mmbtu and was U.S. $5.98/mmbtu on February 11, 2003.

WTI and Husky Realized Crude Oil Price



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
West Texas Intermediate ("WTI") (U.S. $)	$18.48	$20.61	$22.01	$18.40	$17.18	$14.43	$19.24	$30.20	$25.97	$26.08
Husky realized heavy crude oil price	$12.48	$14.33	$16.65	$18.75	$14.16	$8.26	$16.00	$21.26	$15.85	$26.09
Husky realized light/medium crude oil price	$20.00	$19.91	$22.47	$26.62	$25.31	$16.99	$22.63	$33.56	$26.87	$33.86

NYMEX Natural Gas and Husky Realized Natural Gas Price



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
NYMEX natural gas (U.S. $)	$2.16	$1.92	$1.63	$2.55	$2.63	$2.14	$2.27	$3.91	$4.38	$3.25
Husky realized natural gas price	$1.59	$1.76	$1.50	$1.82	$2.21	$2.17	$2.41	$5.16	$5.47	$3.83

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which affect refinery feedstock costs, and third-party refined product purchases. Husky's ability to maintain refined product margins in an environment of higher feedstock costs is contingent upon its ability to pass higher costs on to its customers.

The profitability of Husky's heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil produced exceed the costs of the heavy oil feedstock plus the related operating costs. An increase in the price of blended heavy crude oil feedstock which is not accompanied by an equivalent increase in the price of synthetic crude oil would reduce the profitability of Husky's

upgrading operations. Husky has significant crude oil production that trades at a discount to light crude oil, and any negative effect of a narrower differential on upgrading operations would be more than offset by a positive effect on revenues in the upstream segment.

Husky's portfolio of light, medium and heavy crude oil and natural gas reserves and the efficient operation of its upgrader, refineries and other infrastructure provide opportunities to take advantage of any increases in commodity prices while assisting in managing price volatility.

Foreign Exchange

Husky's results are affected by the exchange rate between the Canadian and U.S. dollars. The majority of Husky's revenues are received in U.S. dollars or from the sale of commodities that receive prices determined by reference to U.S. benchmark prices. Accordingly, a change in the value of the Canadian dollar relative to the U.S. dollar has the effect of increasing or decreasing revenues unlike many of Husky's expenditures, which are in Canadian dollars. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2002, 78 percent or $2.1 billion of Husky's long-term debt and capital securities were denominated in U.S. dollars. At the end of 2002, U.S. $20 million of forward foreign exchange collars were in place with an average cap of $1.54 and floor of $1.49. The terms of the collars range from March 2003 to September 2004. The U.S./Cdn. exchange rate at the end of 2002 was $1.58. On January 23, 2003, the Company executed an arrangement under which it swapped its U.S. $150 million 6.875 percent notes due November 2003. The notes were effectively swapped to $229 million 8.5 percent notes, at an effective exchange rate of $1.525. Refer to note 15 of the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments to manage foreign currency risk.

Interest Rates

Husky is exposed to interest rate fluctuations on its floating rate debt and derivative financial instruments with sensitivity to interest rates. The Company maintains a portion of its total debt in floating rate facilities. The Company will occasionally fix its floating rate debt or create a variable rate for its fixed rate debt using derivative financial instruments.

At December 31, 2002 substantially all of Husky's outstanding long-term debt was at fixed rates, however U.S. $535 million had been swapped to floating rates at an average of London Inter Bank Offered Rate ("LIBOR") plus 1.62 percent. These arrangements mature as follows:

- U.S. $35 million in November 2003
- U.S. $150 million in November 2006
- U.S. $200 million in November 2011
- U.S. $150 million in June 2012

In January, 2003 Husky unwound the U.S. $35 million swap due November 2003. The proceeds amounted to $2.0 million and will be recognized in income over the period to November 2003. In addition $200 million of fixed rate debt was swapped into floating rate debt at Canadian Bankers' Acceptance Rate ("CDOR") plus 1.75 percent until July 2009.

Husky's average effective interest rate during 2002 was 6.70 percent before interest rate swaps and 5.48 percent after swaps. Refer to note 15 of the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments to manage interest rate risk.

Environmental Regulation

Most aspects of Husky's business are subject to environmental laws and regulations. Similar to other companies in the oil and gas industry, Husky incurs costs for preventive and corrective actions. Changes to regulations could have an adverse effect on Husky's results of operations and financial condition.

International Operations

Husky's international operations may be affected by a variety of factors including political and economic developments, expropriation, exchange controls, currency fluctuations, royalty and tax increases, retroactive tax claims, import and export regulations and other foreign laws or policies affecting foreign trade or investment.

Risk Management

Husky uses derivative financial instruments when deemed appropriate to hedge exposure to changes in the price of crude oil and natural gas and fluctuations in interest rates and foreign currency exchange rates. Husky does not engage in transactions involving derivative financial instruments for trading or other speculative purposes. Refer to note 15 of the Consolidated Financial Statements for further disclosure on the Company's use of derivative financial instruments.

Business Plan

Husky's 2003 business plan assumes that:

- WTI will average U.S. $24.00/bbl and the WTI/Lloyd blend differential will average U.S. $6.25/bbl
- NYMEX natural gas price will average U.S. $3.75/mcf
- the Canadian dollar will average U.S. $0.65
- U.S. $LIBOR will average 2.50 percent
- Husky's total production will average 305 to 325 mboe/day. The composition is estimated to be 120 to 130 bbls/day light crude oil & NGL, 85 to 90 mbbls/day heavy crude oil and 580 to 620 mmcf/day natural gas

Husky plans to invest capital in the following segments in 2003:

Year ended December 31 ($ millions)	2003 Estimate
Upstream	
Western Canada	$ 1,040
East Coast Canada	560
International	55
	1,655
Midstream	100
Refined Products	60
Corporate	25
	$ 1,840

Strategic Plan

The 2003 capital program will continue to implement Husky's long-term strategic plan of increasing reserves and production in the upstream business segment and expansion and optimization of the midstream and refined products businesses.

The light crude oil potential of the Western Canada Sedimentary Basin, although considerable, is diminishing since discovery of large accumulations of light crude oil is becoming less probable. Declining production from Husky's light and medium crude oil producing properties in Western Canada is planned to be more than offset by further exploitation of heavy oil in the Lloydminster region of Alberta and Saskatchewan, continued development of oil sands potential in Alberta, production from the White Rose offshore project and further increases of production from new projects in China. Activities related to the development of oil sands in 2003 include submission of an environmental impact assessment and project application for the Tucker and Kearl, Alberta in-situ projects and the drilling of more than 200 stratigraphic test wells at Kearl. Activities in China include evaluation of the newly acquired exploration blocks in the South China Sea. The White Rose development project is progressing and a semi-submersible drilling rig has been secured for development drilling in 2002.

The undiscovered natural gas potential of the Western Canada Sedimentary Basin is considered to be very good and is concentrated in the western portion of the basin. Husky's natural gas production is expected to increase as a result of exploration and development activities concentrated in the foothills and deep basin region west of the fifth meridian in Alberta and British Columbia as well as the northern plains district of Alberta.

During 2003 Husky intends to invest:

- in excess of $1 billion on upstream capital programs located throughout the Western Canada Sedimentary Basin

- approximately $100 million in the midstream segment primarily for further debottlenecking of the Lloydminster Upgrader
- approximately $60 million in the refined products segment primarily for further upgrading of the marketing outlet system

Husky has implemented a corporate hedging plan to protect cash flow and earnings in 2003. The most critical aspect of the plan is to hedge commodity price realizations. The parameters of the plan are as follows:

- crude oil forward sales at a minimum of U.S. $29.00/bbl
- natural gas forward sales at a minimum of U.S. $5.00/mmbtu in non-heating or inventory building months and U.S. $5.25/mmbtu during heating or inventory draw-down months
- no more than 50 percent of annual forecast production will be hedged

There is no plan currently to hedge the Canadian dollar or crude oil differentials.

At February 14, 2003 the Company had hedged 26 mmbbls of crude oil primarily from April through to December 2003 at an average price of U.S. $29.50/bbl. At February, 14, 2003 the Company had hedged 37 bcf of natural gas primarily in the second and third quarters of 2003 at an average price of U.S. $5.20/mmbtu. This amounts to 34 percent of Husky's estimated crude oil production and 17 percent of its estimated natural gas production during 2003. In addition, Husky executed a put option program for approximately 3.7 mmbbls from July to December 2003 at a strike price of U.S. $27.00/bbl. The cost of the program was U.S. $6.1 million.

Results of Operations

Upstream

Upstream Earnings Summary

Year ended December 31 ($ millions)	2002	2001	2000
Gross revenues	$ 3,120	$ 2,667	$ 2,055
Royalties	460	502	351
Hedging (gain)/loss	(5)	—	155
Net revenues	2,665	2,165	1,549
Operating and administrative expenses	729	648	375
Depletion, depreciation and amortization	851	728	407
Income taxes	397	307	315
Earnings	$ 688	$ 482	$ 452

Net Revenue Variance Analysis

($ millions)	Light/ Medium Crude Oil & NGL	Lloyd-minster Heavy Crude Oil	Natural Gas	Other	Total
Year ended December 31, 2000					
Net revenues	$ 632	$ 357	$ 534	$ 26	$ 1,549
Price changes	(348)	(253)	59	(8)	(550)
Volume changes	632	114	404	—	1,150
Royalties	(52)	29	(128)	—	(151)
Hedging	49	102	4	—	155
Processing	—	—	—	12	12
Year ended December 31, 2001					
Net revenues	913	349	873	30	2,165
Price changes	276	297	(342)	8	239
Volume changes	138	81	(7)	—	212
Royalties	(16)	(56)	113	—	41
Hedging	5	—	—	—	5

Processing	—	—	—	3	3
Year ended December 31, 2002					
Net revenues	$ 1,316	$ 671	$ 637	$ 41	$ 2,665

Daily Production, Before Royalties

Year ended December 31	2002	2001	2000
Light/medium crude oil & NGL *(mbbls/day)*	125.9	112.0	63.6
Lloydminster heavy crude oil *(mbbls/day)*	79.4	65.4	53.5
Natural gas *(mmcf/day)*	569.2	572.6	358.0
Barrels of oil equivalent (6:1) *(mboe/day)*	300.2	272.8	176.8

Average Realized Prices

Year ended December 31	2002	2001	2000
Light/medium crude oil & NGL *($/bbl)*	$ 33.16	$ 27.19	$ 35.88
Hedging (gain)/loss	(0.12)	—	2.46
Light/medium crude oil & NGL price realized	$ 33.28	$ 27.19	$ 33.42
Lloydminster heavy crude oil *($/bbl)*	$ 26.09	$ 15.85	$ 26.45
Hedging (gain)/loss	—	—	5.19
Lloydminster heavy crude oil price realized	$ 26.09	$ 15.85	$ 21.26
Natural gas price *($/mcf)*	$ 3.83	$ 5.47	$ 5.18
Hedging (gain)/loss	—	—	0.02
Natural gas price realized	$ 3.83	$ 5.47	$ 5.16

Product Mix

Year ended December 31	2002	2001	2000
Percentage of upstream sales revenues, after royalties			
Light/medium crude oil & NGL	49%	42%	40%
Lloydminster heavy crude oil	25%	16%	23%
Natural gas	26%	42%	37%
	100%	100%	100%

Royalty Rates

Year ended December 31	2002	2001	2000
Percentage of upstream sales revenues, before royalties			
Light/medium crude oil & NGL	15%	19%	20%
Lloydminster heavy crude oil	11%	8%	15%
Natural gas	18%	23%	19%
Total	15%	19%	19%

2002 compared with 2001

Husky's earnings from the upstream segment increased by $206 million (43 percent) to $688 million in 2002 from $482 million in 2001.

Husky's total revenues from upstream operations were $3,120 million in 2002 compared with $2,667 million in 2001 as a result of:

- higher sales volume and price realization for crude oil

the effect of which was offset partially by:

- lower natural gas prices

Higher production volumes of crude oil were due to:

- the ongoing Lloydminster heavy oil development programs
- Terra Nova and Wenchang commencing production in January and July, respectively

Operating costs per unit of production increased three percent in 2002 compared with 2001 as a result of:

- light/medium crude oil properties under secondary and tertiary recovery schemes in Western Canada
- extensive shallow gas production in Western Canada

partially offset by:

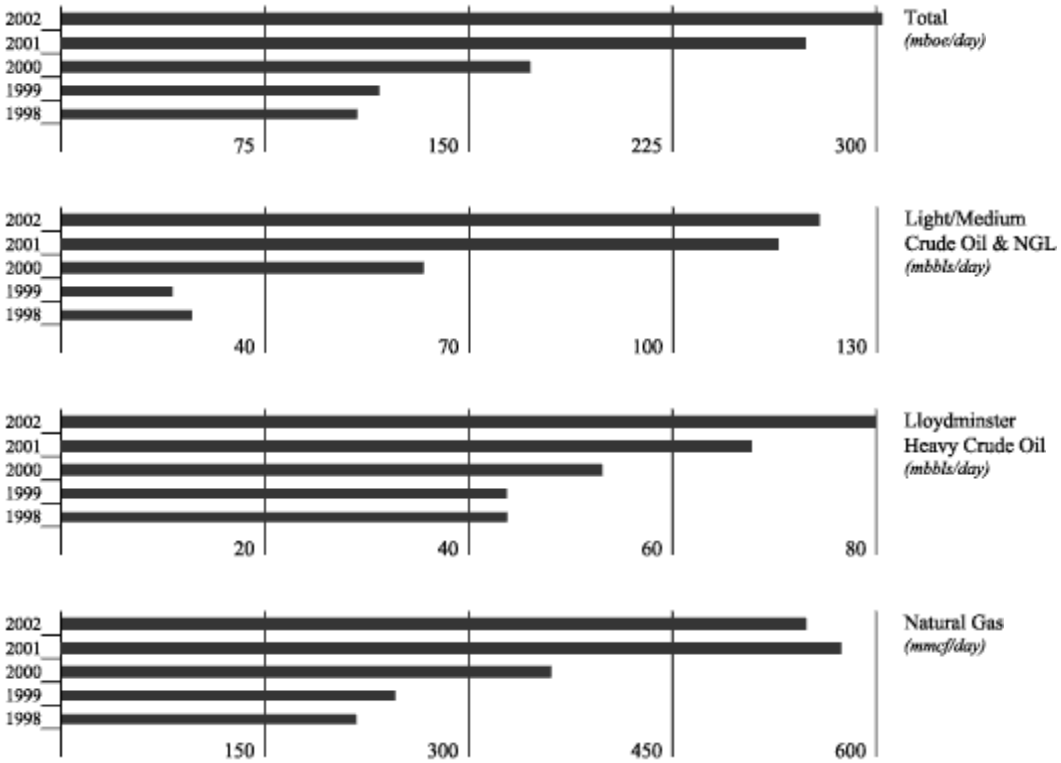
- lower unit operating costs at Terra Nova, Wenchang and at the heavy oil operations at Lloydminster

Depletion, depreciation and amortization ("DD&A") increased to $7.76/boe in 2002 from $7.31/boe in 2001 and resulted from:

- higher maintenance capital for properties under secondary and tertiary recovery and shallow natural gas and offshore operations requiring large infrastructure capital

Income taxes increased in 2002 compared with 2001 reflecting higher pre-tax earnings offset in part by rate reductions in British Columbia and Alberta.

Daily production, before Royalties



Operating Netbacks[1]

Western Canada

Light/Medium Crude Oil Netbacks[2]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 31.10	$ 27.39	$ 35.68
Royalties	5.25	4.87	6.42
Hedging (gain)/loss	(0.15)	—	2.46
Operating costs	8.50	7.47	6.23
Netback	$ 17.50	$ 15.05	$ 20.57

Lloydminster Heavy Crude Oil Netbacks[2]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 26.02	$ 16.00	$ 26.45
Royalties	2.97	1.27	3.00
Hedging (gain)/loss	—	—	5.19
Operating costs	7.03	7.60	6.15
Netback	$ 16.02	$ 7.13	$ 12.11

Natural Gas Netbacks[3]

Year ended December 31 (per mcfge)	2002	2001	2000
Sales revenues	$ 3.96	$ 5.39	$ 5.28
Royalties	0.82	1.30	1.18
Hedging (gain)/loss	—	—	0.02
Operating costs	0.70	0.58	0.49
Netback	$ 2.44	$ 3.51	$ 3.59

Total Western Canada Upstream Netbacks[2]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 27.04	$ 26.42	$ 31.41
Royalties	4.45	5.04	5.42
Hedging (gain)/loss	(0.05)	—	2.40
Operating costs	6.55	6.08	5.27
Netback	$ 16.09	$ 15.30	$ 18.32

Terra Nova Light/Medium Crude Oil Netbacks

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 35.47	$ —	$ —
Royalties	0.36	—	—
Operating costs	3.62	—	—

Netback	$ 31.49	$ —	$ —

(1) 2001 and 2000 amounts as restated. Refer to note 3 of the Consolidated Financial Statements.

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

(3) Includes associated co-products converted to mcfge.

Wenchang Light/Medium Crude Oil Netbacks

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 44.36	$ —	$ —
Royalties	2.65	—	—
Operating costs	2.15	—	—
Netback	$ 39.56	$ —	$ —

Total Upstream Netbacks[1]

Year ended December 31 (per boe)	2002	2001	2000
Sales revenues	$ 28.12	$ 26.42	$ 31.41
Royalties	4.20	5.04	5.42
Hedging (gain)/loss	(0.05)	—	2.40
Operating costs	6.24	6.08	5.27
Netback	$ 17.73	$ 15.30	$ 18.32

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

Upstream Capital Expenditures

Year ended December 31 ($ millions)	2002	2001	2000
Exploration			
Western Canada	$ 304	$ 236	$ 118
East Coast Canada	41	81	63
International	9	5	—
	354	322	181
Development			
Western Canada	730	786	301
East Coast Canada	417	110	131
International	66	99	87
	1,213	995	519
	$ 1,567	$ 1,317	$ 700

Western Canada

Capital expenditures reflect exploration and exploitation of properties in central and southern Alberta, southern Saskatchewan, the foothills, deep basin and northern region of Alberta and north eastern British Columbia and the increasing pace of development in the Lloydminster heavy oil area. Many of the properties located in Alberta and Saskatchewan are crude oil properties under secondary pressure maintenance schemes or shallow natural gas properties, which require extensive optimization and rationalization.

Capital expenditures in the Lloydminster heavy oil areas of Alberta and Saskatchewan in the last two years were $273 million and $324 million, respectively. Husky drilled 369 wells in the Lloydminster area in 2002 compared with 490 wells in 2001 resulting in 327 and 415 oil well completions and 25 and 39 natural gas well completions in 2002 and 2001, respectively. In 2002, expansion of the heavy oil thermal project at Bolney/Celtic, Saskatchewan continued. Capital spending on the project totalled $36 million and productive capacity had been increased from 3,000 bbls/day to 5,000 bbls/day by year-end. Capital spending for the natural gas development in the Shackleton area of southern Saskatchewan totalled $61 million and 2002 exit production volume was approximately 30 mmcf/day.

Exploration spending in Western Canada increased by $68 million to $304 million in 2002 from $236 million in 2001 and $118 million in

2000. Exploration spending remains focused on natural gas prone areas in the deep basin areas of western Alberta and the foothills and northern plains of Alberta and British Columbia.

East Coast Canada

Husky's 2002 capital spending in the Jeanne d'Arc Basin totalled $458 million. Capital spending on the White Rose development project amounted to $395 million (including $24 million of capitalized interest). The Terra Nova oil field development was commissioned in January 2002. Additional development capital spending for Terra Nova amounted to $22 million during the year. The remaining $41 million was for other Jeanne d'Arc Basin exploration.

International

Internationally, Husky's capital expenditures totalled $75 million during 2002, $66 million of which was spent on the Wenchang oil field development in the South China Sea. Wenchang was commissioned in July 2002. The remainder was spent on an exploration program in the South China Sea, which began in late 2002. The Qionghai 18-1-3 well in the South China Sea was plugged and abandoned in January 2003 without testing and the Wenchang 8-1-1 was plugged and abandoned without testing in February, 2003.

Reserve Additions

The efficient replacement of the Company's oil and gas productive capacity is the fundamental key to the growth of value. During the three years ended December 31, 2002, Husky has replaced an average of 120 percent of production on a boe basis, exclusive of acquisitions and divestitures. Over the three years ended December 31, 2002 reserves were added at an average cost of $10.12/boe.

During 2002, extensions of proved acreage and improved recovery added 44 mmbbls to proved reserves of crude oil and NGL, 19 mmbbls of which was from Terra Nova. Technical revisions added 12 mmbbls to crude oil and NGL reserves, primarily from Bolney/Celtic. Net divestitures amounted to 11 mmbbls. During 2002 discoveries, extensions and improved recovery added 387 bcf to proved reserves of natural gas. The larger additions were 133 bcf from Boyer in northern Alberta, 82 bcf from Shackleton in southern Saskatchewan and 36 bcf from discoveries in Kiskiu and Ansell in the Alberta foothills and deep basin. Net divestitures of non-core properties amounted to 13 bcf and technical revisions amounted to negative 37 bcf.

At December 31, 2002, the present value of future net cash flows after tax from the Company's proved oil and gas reserves, based on prices and costs in effect at year-end and discounted at 10 percent, was $7.2 billion compared with $2.8 billion at the end of 2001.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers was engaged to evaluate 65 percent of Husky's proved oil and gas reserves. The firm's aggregate proved reserve estimates were approximately 10 percent lower than Husky's estimates which are set out below.

Summary of Reserves

Light/Medium Crude Oil & NGL Reserves

	2002		2001		2000	
Year ended December 31 (mmbbls)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved developed	323	280	329	287	338	283
Proved undeveloped	65	52	101	89	102	88
Total proved	388	332	430	376	440	371

Lloydminster Heavy Crude Oil Reserves

	2002		2001		2000	
Year ended December 31 (mmbbls)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved developed	116	109	96	92	65	63
Proved undeveloped	65	60	73	72	49	47
Total proved	181	169	169	164	114	110

Natural Gas Reserves

Year ended December 31 (bcf)	2002 Gross	2002 Net	2001 Gross	2001 Net	2000 Gross	2000 Net
Proved developed	1,547	1,273	1,577	1,342	1,580	1,276
Proved undeveloped	548	440	389	332	329	269
Total proved	2,095	1,713	1,966	1,674	1,909	1,545

Barrels of Oil Equivalent

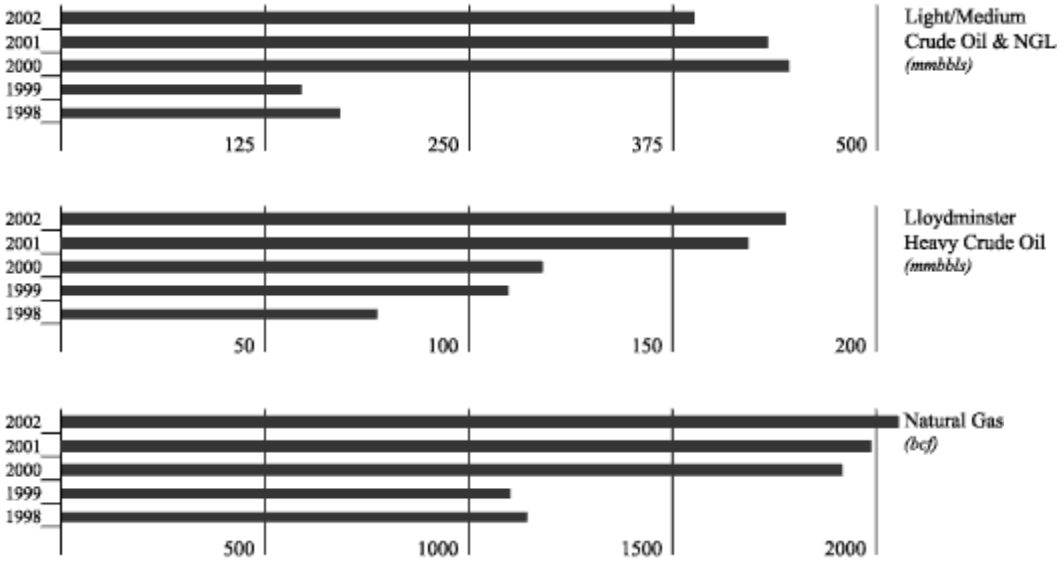
Year ended December 31 (mmboe)	2002 Gross	2002 Net	2001 Gross	2001 Net	2000 Gross	2000 Net
Proved developed	697	601	688	603	666	559
Proved undeveloped	221	185	239	216	206	180
Total proved	918	786	927	819	872	739

Reserve Life Index[1]

Year ended December 31 (years)	2002	2001	2000
Light/medium crude oil & NGL	8.5	10.5	10.2
Lloydminster heavy crude oil	6.2	7.0	5.4
Natural gas	10.0	9.4	9.0
Barrels of oil equivalent	8.4	9.3	8.7

(1) *Includes total proved reserves.*

Gross Proved Reserves



Finding and Development Costs

Total[1]

Year ended December 31	2000-2002	2002	2001	2000
Total capitalized costs *($ millions)*	$3,314.9	$1,505.1	$1,172.0	$ 637.8
Proved reserve additions and revisions *(mmboe)*	327.6	114.5	120.4	92.7
Average cost per boe	$ 10.12	$ 13.14	$ 9.73	$ 6.88

(1) Excludes acquisitions/divestitures.

Western Canada[2]

Year ended December 31	2000-2002	2002	2001	2000
Total capitalized costs *($ millions)*	$2,298.7	$ 978.5	$ 920.1	$ 400.1
Proved reserve additions and revisions *(mmboe)*	256.9	94.8	112.9	49.2
Average cost per boe	$ 8.95	$ 10.32	$ 8.15	$ 8.13

(2) Excludes oil sands and acquisitions/divestitures.

Production Replacement

Total

Year ended December 31	2000-2002	2002	2001	2000
Production *(mmboe)*	273.9	109.6	99.6	64.7
Proved reserve additions and revisions *(mmboe)*	327.6	114.5	120.4	92.7
Production replacement ratio (excluding acquisitions/divestitures) *(percent)*	120	104	121	143
Proved reserve additions and revisions (including acquisitions/divestitures) *(mmboe)*[1]	372.6	100.9	154.5	117.2
Production replacement ratio (including acquisitions/divestitures) *(percent)*[1]	136	92	155	181

Western Canada[2]

Year ended December 31	2000-2002	2002	2001	2000
Production *(mmboe)*	264.3	100.2	99.5	64.6
Proved reserve additions and revisions *(mmboe)*	256.9	94.8	112.9	49.2
Production replacement ratio (excluding acquisitions/divestitures) *(percent)*	97	95	113	76
Proved reserve additions and revisions (including acquisitions/divestitures) *(mmboe)*[1]	301.9	81.2	147.0	73.7
Production replacement ratio (including acquisitions/divestitures) *(percent)*[1]	114	81	148	114

(1) Excludes 2000 Renaissance acquisition.

(2) Excludes oil sands.

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 netback by the proved finding and development cost on a boe basis. Netback is defined as upstream net sales revenues less operating and administrative costs per boe of production.

Total

Year ended December 31	2000-2002	2002	2001	2000
Netback *($/boe)*	$ 16.89	$ 17.66	$ 15.23	$ 18.15
Proved finding and development cost *($/boe)*	$ 10.12	$ 13.14	$ 9.73	$ 6.88
Recycle ratio	1.67	1.34	1.57	2.64

Western Canada[1]

Year ended December 31	2000-2002	2002	2001	2000
Netback *($/boe)*	$ 16.29	$ 16.07	$ 15.21	$ 18.30
Proved finding and development cost *($/boe)*	$ 8.95	$ 10.32	$ 8.15	$ 8.13
Recycle ratio	1.82	1.56	1.87	2.25

(1) Excludes oil sands.

Western Canada Drilling

		2002		2001		2000	
Year ended December 31 (wells)		Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	21	20	78	76	16	13
	Gas	139	131	102	90	30	20
	Dry	15	14	36	34	9	9
		175	165	216	200	55	42
Development	Oil	497	453	594	542	411	363
	Gas	485	453	251	221	92	70
	Dry	58	55	68	63	30	28
		1,040	961	913	826	533	461
Total		1,215	1,126	1,129	1,026	588	503

Undeveloped Land Holdings

	2002		2001	
Year ended December 31 (thousands of acres)	Gross	Net	Gross	Net
Western Canada				
Alberta	5,416	4,907	5,980	5,373
Saskatchewan	2,098	1,986	2,066	1,921
British Columbia	314	273	188	141
Manitoba	13	13	76	75
	7,841	7,179	8,310	7,510
Northwest Territories and Arctic	463	175	1,538	409
Eastern Canada	2,414	2,104	1,878	1,471
Total Canada	10,718	9,458	11,726	9,390
International	4,464	2,066	1,425	697
Total	15,182	11,524	13,151	10,087

Results of Operations
Midstream

Upgrading Earnings Summary

Year ended December 31 ($ millions, except where indicated)	2002	2001	2000
Gross margin	$ 246	$ 428	$ 321
Operating costs	154	192	158
Other expenses (recoveries)	(6)	(12)	5
DD&A	18	17	16
Income taxes	26	73	54
Earnings	$ 54	$ 158	$ 88
Upgrader throughput[1] *(mbbls/day)*	65.4	71.7	70.0
Synthetic crude oil sales *(mbbls/day)*	59.3	59.5	60.6
Upgrading differential *($/bbl)*	$ 10.81	$ 17.91	$ 13.77
Unit operating cost[2] *($/bbl)*	$ 6.48	$ 7.35	$ 6.17

(1) Throughput includes diluent returned to the field.

(2) Based on throughput.

Upgrading Earnings Variance Analysis ($ millions)	
Year ended December 31, 2000	$ 88
Volume	(8)
Differential	115
Operating costs — energy related	(29)
Operating costs — non-energy related	(5)
Other	17
DD&A	(1)
Income taxes	(19)
Year ended December 31, 2001	158
Volume	(1)
Differential	(181)
Operating costs — energy related	39
Operating costs — non-energy related	(1)
Other	(6)
DD&A	(1)
Income taxes	47
Year ended December 31, 2002	$ 54

Infrastructure and Marketing Earnings Summary

Year ended December 31 ($ millions, except where indicated)	2002	2001	2000
Gross margin			
Pipeline	$ 55	$ 86	$ 87
Other infrastructure and marketing	147	111	30
	202	197	117
Other expenses	10	10	1
DD&A	20	17	15
Income taxes	65	72	45
Earnings	$ 107	$ 98	$ 56

Aggregate pipeline throughput *(mbbls/day)*	457	537	528

2002 compared with 2001

Total midstream earnings decreased by $95 million (37 percent) to $161 million in 2002 from $256 million in 2001 due to:

- upgrading differential narrowing to average $10.81/bbl in 2002 versus $17.91/bbl in 2001

partially offset by:

- lower energy related operating costs

Lower throughput in 2002 compared with 2001 was due to a plant turnaround in June and subsequent operational problems. However synthetic crude oil sales in 2002 were augmented by sales of third party product.

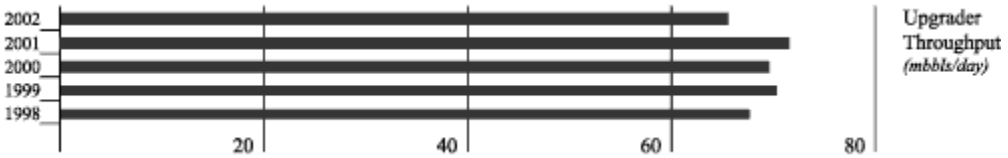
Infrastructure and marketing operations earnings increased nine percent in 2002 due to:

- improved crude oil and natural gas commodity margins
- higher cogeneration income

partially offset by:

- reduced heavy crude pipeline throughput

Lower income taxes in 2002 compared with 2001 related to lower pre-tax earnings and rate reductions in British Columbia and Alberta and federal rate reductions for non-resource income.



Midstream Capital Expenditures

Midstream capital expenditures in 2002 were primarily for upgrader, pipeline and cogeneration plant upgrades and upgrader debottlenecking front-end engineering.

Year ended December 31 ($ millions)	2002	2001	2000
Upgrader	$ 41	$ 47	$ 12
Infrastructure and marketing	17	58	47
	$ 58	$ 105	$ 59

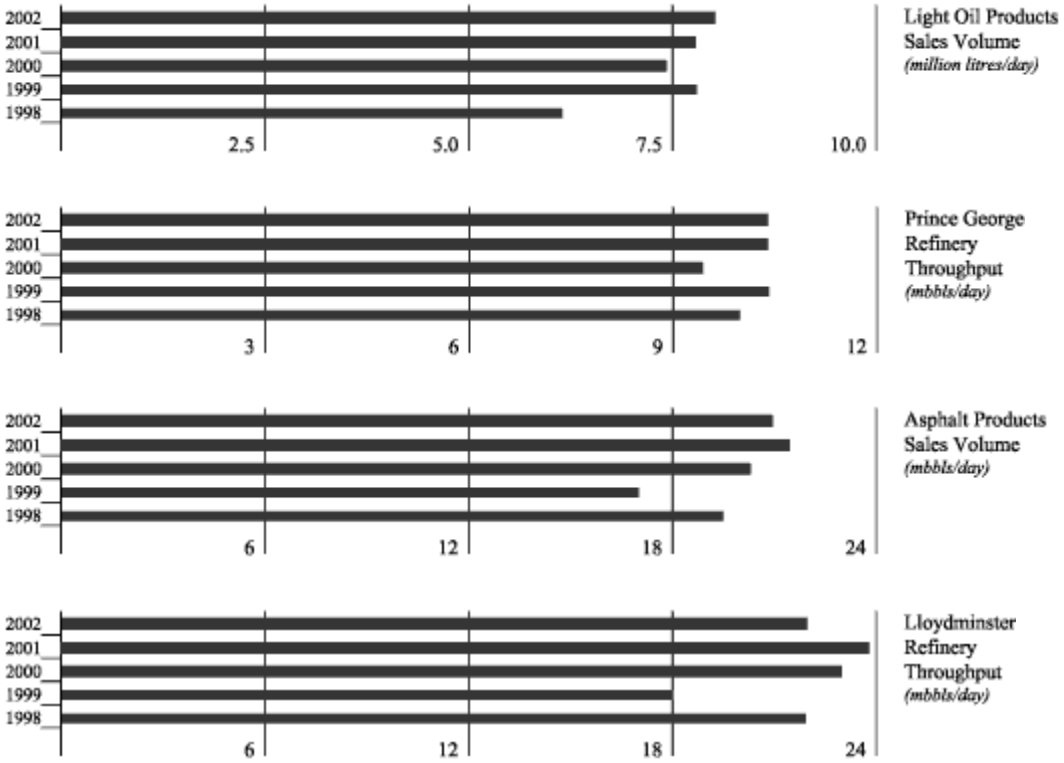
Results of Operations
Refined Products

Refined Products Earnings Summary

Year ended December 31 ($ millions, except where indicated)	2002	2001	2000
Gross margin			
Fuel sales	$ 81	$ 69	$ 55
Ancillary sales	26	27	26
Asphalt sales	45	106	38
	152	202	119
Operating and other expenses	64	59	60
DD&A	34	31	28
Income taxes	22	49	15
Earnings	$ 32	$ 63	$ 16
Number of fuel outlets	571	580	579
Refined product sales volume			
Light oil products *(million litres/day)*	7.7	7.6	7.4
Asphalt products *(mbbls/day)*	20.8	21.4	20.2
Refinery throughput			
Lloydminster refinery *(mbbls/day)*	22.0	23.7	23.4
Prince George refinery *(mbbls/day)*	10.1	10.2	9.2

2002 compared with 2001

Total refined products earnings decreased by $31 million (49 percent) to $32 million in 2002 from $63 million in 2001. Earnings from asphalt product operations were lower in 2002 due to higher heavy crude oil feedstock costs. Light oil refined product earnings increased primarily due to improved fuel margins.



Refined Products Capital Expenditures

In 2002, capital expenditures of $28 million were directed toward marketing outlet improvements, the remainder was spent on refinery maintenance.

Results of Operations
Corporate

Interest

Interest expense less interest income and capitalized interest was $104 million in 2002 compared with $101 million in 2001. Interest capitalized in 2002 was $26 million compared with $51 million in 2001 reflecting the completion of the Terra Nova development project and the resultant cessation of interest being capitalized to the project. Interest continued to be capitalized to the White Rose development project in 2002. Interest income was $1 million in both 2002 and 2001. Total interest paid on short- and long-term debt in 2002 was $131 million compared with $153 million in 2001 reflecting lower interest rates in 2002. Husky's effective interest rate for 2002 after the effect of swaps was 5.48 percent compared with 6.86 percent during 2001.

Foreign Exchange

Foreign exchange losses during 2002 comprised $13 million of cash losses and $11 million of non-cash realized losses on long-term debt offset by $11 million of unrealized gains on long-term debt. Foreign exchange cash losses were related to other monetary items, primarily foreign exchange collars.

In June 2002, U.S. $400 million of 10-year debt securities were issued. The Canadian dollar equivalent on issue was $617 million based on an exchange rate of $1.5432. On December 31, 2002 the exchange rate was $1.5796 generating a loss of approximately $15 million, and offsetting gains on other U.S. dollar denominated debt.

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, as is the practice in the United States, are reflected in earnings in the period they occur. Results from prior periods have been restated to reflect this change. The U.S./Canadian exchange rates expressed in Canadian dollars at December 31, 2002, 2001, 2000 and 1999 were $1.5796, $1.5926, $1.5002 and $1.4433, respectively.

Income Taxes

Income tax expense in 2002 amounted to $420 million, substantially unchanged from 2001. Income tax in 2002 reflected the effect of the British Columbia and Alberta corporate income tax rate reductions and a reduction of the federal corporate income tax rate for non-resource income. Current taxes in 2002 comprised $41 million on Wenchang earnings, $18 million of capital tax and the remainder for other taxes.

At December 31, 2002 Husky's tax pools consisted of the following:

($ millions)	
Canadian Development Expense	$ 960
Canadian Oil and Gas Property Expense	942
Foreign Exploration and Development Expense	247
Undepreciated Capital Costs	1,515
Other	36
	$ 3,700

Corporate Capital Expenditures

Corporate capital expenditures amounted to $23 million in 2002 and $22 million in 2001 and were primarily for computer hardware and software and office furniture and equipment.

Sensitivity Analysis

The following table shows the effect on net earnings and cash flow of changes in certain key variables. The analysis is based on business

conditions and production volumes during 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)	($/share)[6]	($ millions)	($/share)[6]
WTI benchmark crude oil price[1]	U.S. $1.00/bbl	101	0.24	64	0.15
NYMEX benchmark natural gas price[2]	U.S. $0.20/mmbtu	39	0.09	23	0.05
Light/heavy crude oil differential[3]	Cdn. $1.00/bbl	(28)	(0.07)	(17)	(0.04)
Light oil margins	Cdn. $0.005/litre	14	0.03	8	0.02
Asphalt margins	Cdn. $1.00/bbl	8	0.02	5	0.01
Exchange rate (U.S. $ per Cdn. $)[4]	U.S. $0.01	(41)	(0.10)	(26)	(0.06)
Interest rate[5]	1%	(12)	(0.03)	(8)	(0.02)

(1) *Excludes the impact of hedging. Hedged oil volumes at December 31, 2002 were immaterial.*

(2) *Includes decrease in earnings related to natural gas consumption.*

(3) *Includes impact of upstream and upgrading operations only.*

(4) *Assumes no foreign exchange gains or losses on U.S. $ denominated long-term debt and other monetary items. In 2002 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 $19 million in net earnings based on December 31, 2002 U.S. $ denominated debt levels.*

(5) *Interest rate sensitivity based on annual weighted obligations.*

(6) *Based on December 31, 2002 common shares outstanding of 417.9 million.*

Liquidity and Capital Resources

Financial Ratios

Year ended December 31	2002	2001	2000
Cash flow — operating activities *($ millions)*	$ 1,892	$ 1,930	$ 1,209
— financing activities *($ millions)*	$ 3	$ (423)	$ (558)
— investing activities *($ millions)*	$ (1,589)	$ (1,507)	$ (651)
Debt to capital employed *(percent)*	31.8	32.8	37.4
Debt to cash flow from operations	1.1	1.1	1.7
Corporate reinvestment ratio[1]	0.8	0.8	0.6

(1) *Capital and investment expenditures divided by cash flow from operations.*

In 2002 cash generated by operating activities was $1,892 million, a decrease of $38 million from the $1,930 million recorded in 2001 and an increase of $683 million from the $1,209 million in 2000. Lower cash from operating activities in 2002 was primarily due to higher accounts receivable and inventories. Cash used in investing activities amounted to $1,589 million in 2002, an increase of $82 million from the $1,507 million in 2001 and an increase of $938 million from the $651 million in 2000.

In 2002 cash provided from financing activities comprised $972 million from the issuance of long-term debt and $9 million of proceeds from the exercise of stock options. Cash utilized by financing activities in 2002 comprised $778 million for debt repayment, $151 million for dividends on common shares, $31 million for return on capital securities payment, $9 million for debt issue costs and a change of $9 million in non-cash working capital.

In 2001 financing activities utilized a net $423 million comprising debt repayments, net of issues, of $290 million, dividends of $150 million, return on capital securities payment of $30 million and reduction of site restoration provision of $4 million partially offset by a change of $42 million in non-cash working capital and proceeds of $9 million from the exercise of stock options.

In 2002 investing activities comprised $1,695 million for capital expenditures and acquisition costs partially offset by asset sales of

$93 million and other adjustments of $13 million. In 2001 investing activities comprised $1,598 million of capital expenditures and acquisition costs partially offset by asset sales of $67 million and other adjustments of $24 million.

Cash and cash equivalents at December 31, 2002 totalled $306 million compared with a nil balance at the beginning of the year. During January 2003, $200 million of the cash was utilized to settle the accounts under the Company's receivable sales agreement outstanding at the end of the year. Total debt, net of cash and cash equivalents was $2,079 million at December 31, 2002.

Financing Activities

As at December 31, 2002 Husky's outstanding long-term debt totalled $2,385 million, including amounts due within one year, compared with $2,092 million at December 31, 2001.

At December 31, 2002 there were no drawings under the Company's $940 million revolving syndicated credit facility. Interest rates on this facility vary and are 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.

At December 31, 2002 the Company had utilized in support of letters of credit $12 million of its $195 million in short-term credit facilities. The interest rates applicable to these facilities vary and are based on Canadian prime, Bankers' Acceptance, money market rates or U.S. dollar equivalents.

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 9 of the Consolidated Financial Statements.

Effective January 23, 2003 the Company swapped the U.S. $150 million 6.875 percent notes due November 2003 to $229 million 8.5 percent debt due November 2003. This transaction effectively fixes the exchange rate on the U.S. notes at $1.525. As a result there will be no future foreign exchange gains or losses on these notes up to their maturity date.

The Company has an agreement to sell up to $200 million of net trade receivables 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 in 2002 was approximately 2.8 percent (2001 — 4.7 percent). The Company has potential exposure to an immaterial amount of credit loss under this agreement. As at December 31, 2002 $200 million of net trade receivables had been sold.

The Company believes that, based on its current forecast for commodity prices for 2003, together with the corporate hedging plan its capital program of $1.8 billion will be funded by operating activities and, to the extent required, available lines of credit. In the event of significantly lower cash flow the Company is able to defer certain of its capital spending programs without penalty.

The Company declared dividends aggregating $0.36 per share ($151 million) in 2002. The board of directors of Husky has established a dividend policy that pays quarterly dividends of $0.09 ($0.36 annually) per common share. However, there can be no assurance that further dividends will be declared. The declaration of dividends will be at the discretion of the Board of Directors which will consider earnings, capital requirements, financial condition of the Company and other relevant factors.

At December 31, 2002 Husky had the following credit ratings:

	Rating	Debt Rated
Standard and Poor's Rating Service	BBB	Senior unsecured debt
	BB+	Capital securities
	BBB	8.45% senior secured bonds
Moody's Investor Service	Baa2	Senior unsecured debt
	Ba1	Capital securities
	Baa2	8.45% senior secured bonds
Dominion Bond Rating Service	BBB (high)	Senior unsecured long-term notes
	BBB	Capital securities

SIGNIFICANT ACCOUNTING POLICIES

The preparation of financial statements in accordance with generally accepted accounting principles requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. The following is included in Management's Discussion and Analysis to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which

affect the application of these policies and practices. Significant accounting policies are disclosed in note 3 of the Consolidated Financial Statements. Inherent in the application of a number of these policies is the requirement of management to make certain assumptions and interpretations that affect the determination of assets, liabilities, revenues and expenses. Accordingly, the emergence of new information and changed circumstances can cause material changes in reported financial results.

The following assessment of significant accounting policies is not meant to be exhaustive. Materially different results might occur from the application of the entire series of accounting policies to which the Company might be subject. Additionally, the Company might realize different results from the application of new accounting standards promulgated by various rule-making bodies.

Proved Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas liquids including condensate and natural gas that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered proved if they can be produced economically as demonstrated by either actual production or conclusive formation tests. Reserves which must be produced through the application of enhanced recovery techniques are included in the proved category only after successful testing by a pilot project or operation of an installed program in the same reservoir that provides support for the engineering analysis on which the project was based. Proved developed reserves are expected to be produced through existing wells and with existing facilities and operating methods.

The estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's plans. The effect of changes in proved oil and gas reserves on the financial results and position of the Company is described under the heading "Full Cost Accounting for Oil and Gas Activities".

Full Cost Accounting for Oil and Gas Activities

Depletion Expense

The Company uses the Full Cost Method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs, estimated future development costs and estimated removal and site restoration costs is amortized using the unit of production method based on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves will result in a corresponding reduction in depletion expense. A decrease in estimated future development costs will result in a corresponding reduction in depletion expense.

Withheld Costs

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Ceiling Test

The Full Cost Method of accounting requires the calculation of a ceiling test which limits the net capital costs carried to an amount that is equal to or less than the estimated future net cash inflows from the Company's oil and gas properties, including net cost less impairment of unproved properties. The test is a cost recovery test and is not intended to represent an estimate of fair market value. The test is performed quarterly. If the net carrying cost of the oil and gas properties exceeds the indicated limit then the difference is charged to earnings.

Impairment of Long-lived Assets

In addition to testing the permitted limits of oil and gas asset carrying costs, the Company is required to review the carrying value of all other property, plant and equipment for potential impairment. The review for impairment compares the carrying cost to the estimated fair value of the long-lived asset and if the carrying cost exceeds the fair value the difference is charged to earnings.

Asset Retirement Obligations

The Company is required to provide for future removal and site restoration costs, net of expected recoveries. The Company must estimate these costs in accordance with existing laws, contracts or other policies and

must estimate the expected recoveries, which is generally the salvage value or residual value of an asset. These estimated net costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to both determine whether a loss is probable based on judgement and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstance.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, actual income tax liability may differ significantly from that estimated and recorded by management.

New Accounting Standards

In June 2001 the Financial Accounting Standards Board issued Statement No. 143 "Accounting for Asset Retirement Obligations". Financial Accounting Statement ("FAS") 143 requires an entity to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When initially recorded, the liability is added to the related property, plant and equipment, subsequently increasing depletion, depreciation and amortization expense. In addition, the liability is accreted for the change in present value in each period. Upon adoption of FAS 143 the Company will adjust its existing future removal and site restoration liability using the cumulative-effect approach. FAS 143 is effective for fiscal years commencing on or after January 1, 2003. The Canadian Institute of Chartered Accountants issued an exposure draft entitled "Asset Retirement Obligations" in April 2002 that is substantially the same as FAS 143 and is effective for fiscal years beginning on or after January 1, 2004.

The Company has estimated that the cumulative effect will be an increase of the future removal and site restoration liability of $58 million, an increase of related net property, plant and equipment of $56 million, a decrease to the future income tax liability of $1 million and a decrease in retained earnings of $1 million.

RESULTS OF OPERATIONS FOR 2001 COMPARED WITH 2000

Upstream

The increase in upstream revenues for 2001 was due to:

- higher production of crude oil and natural gas from the acquisition of Renaissance
- heavy oil exploitation programs in the Lloydminster heavy oil area
- higher realized natural gas prices

partially offset by:

- lower crude oil and NGL prices

Operating costs per unit of production increased 13 percent in 2001 as a result of:

- increased production of heavier gravity crude oil
- the operation of mature properties under waterflood and a higher proportion of low pressure shallow natural gas

Total DD&A per boe was $7.31 in 2001 compared with $6.28 in 2000. The increase in the DD&A rate was primarily due to a full year of operations for the Renaissance properties.

Midstream

Higher earnings in 2001 was primarily due to wider upgrading differentials and improved crude oil and natural gas commodity marketing volumes and margins partially offset by higher energy related operating costs.

Refined Products

Asphalt product operations accounted for most of the improved earnings in 2001 due to the lower cost feedstock and increased sales volume.

Corporate

Capitalized interest was primarily in respect of Terra Nova and White Rose projects. Interest paid in 2000 included $9 million in respect of the partial redemption of the Husky Terra Nova 8.45 percent senior secured bonds. Husky's average interest rate in 2001 was approximately 6.9 percent compared with 7.5 percent in 2000.

QUARTERLY FINANCIAL SUMMARY

	2002				2001			
($ millions, except where indicated)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Sales and operating revenues, net of royalties	$ 1,697	$ 1,669	$ 1,659	$ 1,359	$ 1,615	$ 1,470	$ 1,731	$ 1,780
Net earnings	$ 242	$ 173	$ 263	$ 126	$ 45	$ 118	$ 299	$ 192
Net earnings per share								
— Basic	$ 0.57	$ 0.38	$ 0.64	$ 0.29	$ 0.09	$ 0.25	$ 0.74	$ 0.42
— Diluted	$ 0.57	$ 0.38	$ 0.64	$ 0.29	$ 0.09	$ 0.24	$ 0.73	$ 0.42
Cash flow from operations	$ 635	$ 590	$ 498	$ 373	$ 287	$ 478	$ 561	$ 620
Cash flow from operations per share								
— Basic	$ 1.50	$ 1.39	$ 1.18	$ 0.88	$ 0.67	$ 1.13	$ 1.33	$ 1.47
— Diluted	$ 1.50	$ 1.39	$ 1.17	$ 0.87	$ 0.66	$ 1.12	$ 1.32	$ 1.46
Share price								
— High	$ 17.20	$ 17.00	$ 17.98	$ 17.80	$ 20.25	$ 20.95	$ 17.30	$ 15.80
— Low	$ 15.43	$ 14.00	$ 15.85	$ 14.20	$ 15.06	$ 14.65	$ 13.10	$ 13.20
— Close (end of period)	$ 16.47	$ 16.70	$ 16.66	$ 17.10	$ 16.47	$ 17.85	$ 16.22	$ 13.25
Shares traded *(thousands)*	20,478	30,620	31,159	34,383	59,251	46,993	25,333	25,280
Number of weighted average common shares outstanding *(thousands)*								
— Basic	417,748	417,497	417,393	416,939	416,545	416,025	415,878	415,805
— Diluted	419,567	419,136	419,558	418,951	419,367	419,153	418,337	417,555

Exhibit 2

HUSKY ENERGY INC.

CONSOLIDATED FINANCIAL STATEMENTS

For the Year Ended December 31, 2002

MANAGEMENT'S REPORT

The management of Husky Energy Inc. is responsible for the financial information and operating data presented in this annual report.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgements. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this annual report has been prepared on a basis consistent with that in the financial statements.

Husky Energy Inc. maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of non-management Directors, meets regularly with management, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy, financial reporting matters and reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board.

The consolidated financial statements have been audited by KPMG, the independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. KPMG have full and free access to the Audit Committee.

John C.S. Lau
President &
Chief Executive Officer

Neil McGee
Vice President &
Chief Financial Officer

Calgary, Alberta, Canada

February 5, 2003

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2002, 2001 and 2000 and the consolidated statements of earnings, retained earnings (deficit), and cash flows for each of the years in the three-year period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards and auditing standards generally accepted in the United States of America. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002, 2001 and 2000 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2002 in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta, Canada
Chartered Accountants

February 5, 2003

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of dollars)	2002	2001	2000
Assets			
Current assets			
Cash and cash equivalents	$ 306	$ —	$ —
Accounts receivable	572	376	715
Inventories (*note 4*)	243	226	186
Prepaid expenses	23	24	27
	1,144	626	928
Property, plant and equipment, net (*notes 1, 5*) (full cost accounting)	9,347	8,715	7,841
Other assets (*note 9*)	84	29	60
	$ 10,575	$ 9,370	$ 8,829
Liabilities and Shareholders' Equity			
Current liabilities			
Bank operating loans (*note 8*)	$ —	$ 100	$ 34
Accounts payable and accrued liabilities	811	821	1,076
Long-term debt due within one year (*note 9*)	421	144	33
	1,232	1,065	1,143
Long-term debt (*note 9*)	1,964	1,948	2,311
Site restoration provision (*note 5*)	249	212	178
Future income taxes (*note 10*)	2,003	1,659	1,212
Shareholders' equity			
Capital securities and accrued return (*note 12*)	364	367	344
Common shares (*note 11*)	3,406	3,397	3,388
Retained earnings	1,357	722	253
	5,127	4,486	3,985
Commitments and contingencies (*note 14*)	$ 10,575	$ 9,370	$ 8,829

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 and 2000 amounts as restated (note 3).

On behalf of the Board:

John C.S. Lau
Director

Martin J.G. Glynn
Director

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31 (millions of dollars, except per share amounts)	2002	2001	2000
Sales and operating revenues, net of royalties	$ 6,384	$ 6,596	$ 5,066
Costs and expenses			
Cost of sales and operating expenses	4,009	4,425	3,492
Selling and administration expenses	94	88	67
Depletion, depreciation and amortization (*notes 1,5*)	939	807	481
Interest — net (*note 9*)	104	101	101
Foreign exchange	13	94	39
Other — net	1	7	85
	5,160	5,522	4,265
Earnings before income taxes	1,224	1,074	801
Income taxes (*note 10*)			
Current	66	20	12
Future	354	400	351
	420	420	363
Net earnings	$ 804	$ 654	$ 438
Earnings per share (*note 11*)			
Basic	$ 1.88	$ 1.49	$ 1.28
Diluted	$ 1.88	$ 1.48	$ 1.28

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT)

Year ended December 31 (millions of dollars)	2002	2001	2000
Beginning of year	$ 722	$ 253	$ (295)
Net earnings	804	654	438
Dividends on common shares	(151)	(150)	—
Return on capital securities (*note 12*)	(29)	(53)	(43)
Related future income taxes (*note 10*)	11	18	16
Reduction of stated capital	—	—	160
Foreign exchange (retroactive adjustment) *(note 3)*	—	—	(15)
Employee future benefits (*note 13*)	--	--	(8)
End of year	$ 1,357	$ 722	$ 253

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 and 2000 amounts as restated (note 3).

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars, except per share amounts)	2002	2001	2000
Operating activities			
Net earnings	$ 804	$ 654	$ 438
Items not affecting cash			
Depletion, depreciation and amortization	939	807	481
Future income taxes	354	400	351
Foreign exchange — non-cash (*note 3*)	—	82	44
Other	(1)	3	85
Cash flow from operations	2,096	1,946	1,399
Change in non-cash working capital (*note 7*)	(204)	(16)	(190)
	1,892	1,930	1,209
Financing activities			
Bank operating loans financing — net	(100)	66	3
Long-term debt issue	972	—	535
Long-term debt repayment	(678)	(356)	(800)
Redemption of preferred shares	—	—	(364)
Return on capital securities payment	(31)	(30)	(30)
Debt issue costs	(9)	—	—
Deferred credits	—	(4)	(4)
Proceeds from exercise of stock options	9	9	—
Dividends on common shares	(151)	(150)	—
Change in non-cash working capital (*note 7*)	(9)	42	102
	3	(423)	(558)
Available for investing	1,895	1,507	651
Investing activities			
Capital expenditures	(1,692)	(1,473)	(803)
Corporate acquisitions	(3)	(125)	(38)
Asset sales	93	67	2
Other	(20)	6	80
Change in non-cash working capital (*note 7*)	33	18	108
	(1,589)	(1,507)	(651)
Increase in cash and cash equivalents	306	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of year	$ 306	$ —	$ —
Cash flow from operations per share (*note 11*)			
Basic	$ 4.94	$ 4.60	$ 4.26
Diluted	$ 4.92	$ 4.57	$ 4.26

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2001 and 2000 amounts as restated (note 3).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

Note 1
Segmented Financial Information

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Year ended December 31									
Sales and operating revenues, net of royalties	$ 2,665	$ 2,165	$1,549	$ 909	$ 886	$1,006	$4,230	$4,380	$2,309
Costs and expenses									
Operating, cost of sales, selling and general	729	648	375	811	638	848	4,038	4,193	2,193
Depletion, depreciation and amortization	851	728	407	18	17	16	20	17	15
Interest — net	—	—	—	—	—	—	—	—	—
Foreign exchange	—	—	—	—	—	—	—	—	—
	1,580	1,376	782	829	655	864	4,058	4,210	2,208
Earnings (loss) before income taxes	1,085	789	767	80	231	142	172	170	101
Current income taxes	55	17	10	1	1	1	6	1	—
Future income taxes	342	290	305	25	72	53	59	71	45
Net earnings (loss)	$ 688	$ 482	$ 452	$ 54	$ 158	$ 88	$ 107	$ 98	$ 56
Capital employed — As at December 31 [(2)]	$ 6,040	$ 5,715	$5,398	$ 319	$ 320	$ 352	$ 431	$ 395	$ 312
Property, plant and equipment — As at December 31									
Cost									
Canada	$11,525	$10,353	$9,023	$ 998	$ 958	$ 912	$ 591	$ 575	$ 510
International	469	394	290	—	—	—	—	—	—
	$11,994	$10,747	$9,313	$ 998	$ 958	$ 912	$ 591	$ 575	$ 510
Accumulated depletion, depreciation and amortization									
Canada	$ 3,894	$ 3,272	$2,622	$ 372	$ 354	$ 337	$ 184	$ 165	$ 148
International	185	147	139	—	—	—	—	—	—
	$ 4,079	$ 3,419	$2,761	$ 372	$ 354	$ 337	$ 184	$ 165	$ 148
Net									
Canada	$ 7,631	$ 7,081	$6,401	$ 626	$ 604	$ 575	$ 407	$ 410	$ 362
International	284	247	151	—	—	—	—	—	—
	$ 7,915	$ 7,328	$6,552	$ 626	$ 604	$ 575	$ 407	$ 410	$ 362
Total assets — As at December 31									
Canada	$ 7,883	$ 7,160	$6,584	$ 658	$ 644	$ 613	$ 850	$ 862	$1,000
International	337	247	151	—	—	—	—	—	—
	$ 8,220	$ 7,407	$6,735	$ 658	$ 644	$ 613	$ 850	$ 862	$1,000

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

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

Comparative figures have been restated to conform with current year's classification.

	Refined Products			Corporate and Eliminations [1]			Total		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Year ended December 31									
Sales and operating revenues, net of royalties	$1,310	$1,349	$1,347	$(2,730)	$(2,184)	$(1,145)	$ 6,384	$ 6,596	$ 5,066
Costs and expenses									
Operating, cost of sales, selling and general	1,222	1,206	1,288	(2,696)	(2,165)	(1,060)	4,104	4,520	3,644
Depletion, depreciation and amortization	34	31	28	16	14	15	939	807	481
Interest — net	—	—	—	104	101	101	104	101	101
Foreign exchange	—	—	—	13	94	39	13	94	39
	1,256	1,237	1,316	(2,563)	(1,956)	(905)	5,160	5,522	4,265
Earnings (loss) before income taxes	54	112	31	(167)	(228)	(240)	1,224	1,074	801
Current income taxes	4	1	1	—	—	—	66	20	12
Future income taxes	18	48	14	(90)	(81)	(66)	354	400	351
Net earnings (loss)	$ 32	$ 63	$ 16	$ (77)	$ (147)	$ (174)	$ 804	$ 654	$ 438
Capital employed — As at December 31 [2]	$ 338	$ 329	$ 351	$ 384	$ (81)	$ (50)	$ 7,512	$ 6,678	$ 6,363
Property, plant and equipment — As at December 31									
Cost									
Canada	$ 702	$ 655	$ 628	$ 165	$ 143	$ 108	$13,981	$12,684	$11,181
International	—	—	—	—	—	—	469	394	290
	$ 702	$ 655	$ 628	$ 165	$ 143	$ 108	$14,450	$13,078	$11,471
Accumulated depletion, depreciation and amortization									
Canada	$ 360	$ 330	$ 302	$ 108	$ 95	$ 82	$ 4,918	$ 4,216	$ 3,491
International	—	—	—	—	—	—	185	147	139
	$ 360	$ 330	$ 302	$ 108	$ 95	$ 82	$ 5,103	$ 4,363	$ 3,630
Net									
Canada	$ 342	$ 325	$ 326	$ 57	$ 48	$ 26	$ 9,063	$ 8,468	$ 7,690
International	—	—	—	—	—	—	284	247	151
	$ 342	$ 325	$ 326	$ 57	$ 48	$ 26	$ 9,347	$ 8,715	$ 7,841
Total assets — As at December 31									
Canada	$ 534	$ 428	$ 487	$ 313	$ 29	$ (6)	$10,238	$ 9,123	$ 8,678
International	—	—	—	—	—	—	337	247	151
	$ 534	$ 428	$ 487	$ 313	$ 29	$ (6)	$10,575	$ 9,370	$ 8,829

Note 2
Nature of Operations and Organization

HUSKY ENERGY INC. ("Husky" or "the Company") is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta.

Management has segmented the Company's business based on differences in products and services and management strategy and responsibility. The Company's business is conducted predominantly through three major business segments - upstream, midstream and refined products.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's upstream operations are located primarily in Western Canada, offshore Eastern Canada (East Coast), South China Sea (Wenchang), with some interests outside Canada (International).

Midstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading); marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke; and pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas and cogeneration of electrical and thermal energy (Infrastructure and marketing).

Refined products includes refining of crude oil and marketing of refined petroleum products including gasoline, alternative fuels and asphalt.

Note 3
Significant Accounting Policies

These financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 16, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries.

A significant part of the Company's activities is conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate interest in these activities.

Certain prior years' amounts have been reclassified to conform with current presentation.

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 net earnings or cash flow of the Company as a result of this change.

a) Cash and Cash Equivalents

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

b) Inventory Valuation

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories are valued at the lower of cost, on a first-in, first-out basis, or net realizable value. Materials and supplies are stated at average cost. Cost consists of raw material, labour, direct overhead and transportation. Intersegment profits are eliminated.

c) Property, Plant and Equipment

i) Oil and Gas

The Company employs the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities. Interest is capitalized on certain major capital projects based on the Company's long-term cost of borrowing.

The provision for depletion of oil and gas properties and depreciation of associated production facilities is calculated using the unit of production method, based on proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until the earliest of when a portion of the property becomes capable of production, or when development activity ceases, or when impairment occurs.

The aggregate carrying values of oil and gas interests are subject to cost recovery ceiling tests. Net capitalized costs in each cost centre are limited to the estimated future net revenues from proved oil and gas reserves, at prices and costs in effect at year-end, plus the cost of unproved properties and major development projects, less impairment. In addition, the net capitalized costs of all cost centres, less related future income taxes, are limited to the estimated future net revenues from all cost centres plus the net cost of major development projects and unproved properties less future removal and site restoration costs, administrative expenses, financing costs and income taxes. Any amounts in excess of these limits are charged to earnings.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment, except upgrading assets, is provided using the straight-line method based on estimated useful lives of assets. Depreciation for upgrading assets is provided using the unit of production method, based on the plant's estimated productive life. When the net carrying amount of other plant and equipment, less related accumulated provisions for future removal and site restoration costs and future income taxes, exceeds the net recoverable amount, the excess is charged to earnings. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Major turnaround costs are deferred when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Future Removal and Site Restoration Costs

Future removal and site restoration costs net of expected recoveries, where they are probable and can be reasonably estimated, are provided for using the method of depletion or depreciation related to the asset. Costs are estimated by the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in the provision for depletion, depreciation and amortization. Removal and site restoration expenditures are charged to the accumulated provision as incurred.

d) Financial Instruments

Gains and losses related to financial instruments designated as hedges are deferred and recognized in the period and in the same financial statement category in which the revenues or expenses associated with the hedged transactions are recognized.

In November 2001, the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") issued an Accounting Guideline "Hedging Relationships" that establishes standards for the documentation and effectiveness of hedging activities that are substantially similar to the corresponding requirements in Financial Accounting Standards Board ("FASB") Statement No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133"). The new recommendations will be effective January 1, 2004. Note 16 discloses the impact of FAS 133 on the financial statements for 2002.

e) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded on a gross basis when title passes to an external party. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

f) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars using average rates for the year for revenue and expenses, except depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets are translated at current exchange rates and non-monetary assets are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings. Capital securities are adjusted to the current rate of exchange and included in retained earnings.

Effective January 1, 2002, the Company retroactively adopted the revised recommendations of the CICA 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, 2000 of $15 million and a reduction of earnings after tax of $47 million and $26 million for the years ended December 31, 2001 and 2000, respectively. 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.

g) Stock-based Compensation Plans

In accordance with the Company's stock option plan, common share options are granted to directors, officers and certain other employees. The Company does not recognize compensation expense on the issuance of common share options under this plan because the exercise price of the share options is equal to the market value of the common shares when

they are granted. In accordance with CICA section 3870 "Stock-based Compensation and Other Stock-based Payments", note 11 discloses the impact on the financial statements for options granted after January 1, 2002. The standards are substantially similar to those in FASB Statement No. 123 "Accounting for Stock-based Compensation" ("FAS 123"). Note 16 presents the disclosures required by FAS 123 in the financial statements.

h) Earnings Per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. In addition, diluted common shares also include the effect of the potential exercise of any outstanding warrants.

i) Impairment or Disposal of Long-term Assets

In December 2002, the AcSB of the CICA approved new standards for the impairment and disposal of long-lived assets that are substantially equivalent to those in FASB Statement No. 144 "Accounting for the Impairment or Disposal of Long-term Assets" ("FAS 144"). Note 16 presents the disclosures required by FAS 144 in the financial statements.

Note 4
Inventories

	2002	2001	2000
Crude oil and refined petroleum products	$ 166	$ 140	$ 132
Natural gas	50	69	41
Materials, supplies and other	27	17	13
	$ 243	$ 226	$ 186

Note 5
Property, Plant and Equipment

Refer to note 1 "Segmented Financial Information" which presents the Company's property, plant and equipment by segment.

Costs of oil and gas properties, including major development projects, excluded from costs subject to depletion and depreciation at December 31 were as follows:

	2002	2001	2000
Canada	$ 1,318	$ 1,226	$ 1,073
International	37	235	137
	$ 1,355	$ 1,461	$ 1,210

The Company has estimated future removal and site restoration costs of $703 million at December 31, 2002 (2001 — $653 million; 2000 — $619 million). During 2002 actual removal and site restoration expenditures amounted to $17 million (2001 — $18 million; 2000 — $10 million).

Note 6
Plan of Arrangement

On June 18, 2000 Husky Oil Limited and Renaissance Energy Ltd. ("Renaissance") agreed to a Plan of Arrangement whereby Husky Oil Limited and its principal subsidiary, Husky Oil Operations Limited ("HOOL"), would merge with Renaissance and continue as HOOL. The Plan of Arrangement also included the incorporation of a new company, Husky Energy Inc. Husky is the parent company of HOOL and is publicly traded. The transaction became effective August 25, 2000 and the results of Husky include those of Renaissance from that date forward.

The allocation of the aggregate purchase price based on the estimated fair values of the Renaissance net assets at August 25, 2000 were as follows:

	Allocation
Net assets acquired	
Working capital	$ 84
Property, plant and equipment	3,514
Marketing and transportation	(131)
Other assets	23
Acquisition costs	(51)
Site restoration provision	(70)
Future income taxes	(60)
Long-term debt	(1,211)
	$ 2,098
Consideration	
Common shares exchanged	$ 1,734
Preferred shares issued	364
	$ 2,098

Note 7
Cash Flows — Change in Non-cash Working Capital

a) Changes in non-cash working capital were as follows:

	2002	2001	2000
Decrease (increase) in non-cash working capital			
Accounts receivable	$ (153)	$ 361	$ (254)
Inventories	(17)	(40)	(38)
Prepaid expenses	1	3	2
Accounts payable and accrued liabilities	(11)	(280)	310
Change in non-cash working capital	(180)	44	20
Relating to:			
Financing activities	(9)	42	102
Investing activities	33	18	108
Operating activities	$ (204)	$ (16)	$ (190)

b) Other cash flow information:

	2002	2001	2000
Cash taxes paid	$ 20	$ 13	$ 9
Cash interest paid	$ 139	$ 145	$ 138

Note 8
Bank Operating Loans

At December 31, 2002 the Company had short-term borrowing lines of credit with banks totalling $195 million; (2001 — $195 million; 2000 — $234 million), of which $12 million (2001 — $102 million; 2000 — $84 million) had been used for bank operating loans and letters of credit. Interest payable is based on Bankers' Acceptance, money market, or prime rates. During 2002, the weighted average interest rate on short-term borrowings was approximately 2.9 percent.

Note 9
Long-term Debt

		Maturity	2002	2001	2000
Long-term debt					
Revolving syndicated credit facility					
	-2001 U.S. $116		$ —	$ 185	$ 174
Non-revolving syndicated credit facility			—	—	300
6.25% notes	*-U.S. $400*	2012	632	—	—
6.875% notes	*-U.S. $150*	2003	237	239	225
7.125% notes	*-U.S. $150*	2006	237	239	225
7.55% debentures	*-U.S. $200*	2016	316	318	300
8.45% senior secured bonds	*-2002 U.S. $162*	2003-12	256	276	268
	-2001 U.S. $173				
	-2000 U.S. $179				
Private placement notes	*-2002 U.S. $68*	2003-5	107	135	152
	-2001 U.S. $85				
	-2000 U.S. $101				
Medium-term notes		2003-9	600	700	700
Total long-term debt			2,385	2,092	2,344
Amount due within one year			(421)	(144)	(33)
			$ 1,964	$ 1,948	$ 2,311

Interest — net for the years ended December 31 were as follows:

	2002	2001	2000
Long-term debt	$ 128	$ 148	$ 144
Short-term debt	3	5	4
	131	153	148
Amount capitalized	(26)	(51)	(43)
	105	102	105
Interest income	(1)	(1)	(4)
	$ 104	$ 101	$ 101

As at December 31, 2002, other assets included $23 million (2001 — $17 million; 2000 — $20 million) of deferred debt issue costs.

The revolving syndicated credit facility allows the Company to borrow up to $940 million in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lenders do not consent to such extension, the revolving credit facility will convert to a four-year non-revolving amortizing term loan. Interest rates 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 credit rating agencies to the Company's rated senior unsecured debt and whether the Company borrows under the revolving or non-revolving condition.

The 6.25 percent notes were issued June 14, 2002 and rank on equal footing with other unsecured indebtedness of the Company. The notes mature June 15, 2012 and are redeemable at the option of the Company at any time. Interest is payable semi-annually. The notes were issued under a base shelf prospectus dated June 6, 2002 filed with securities regulatory authorities in Canada and the United States. The prospectus permits Husky to offer for sale, from time to time, up to U.S. $1 billion of debt securities during the 25 months from June 6, 2002.

The 6.875 percent notes, the 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. Such securities mature in 2003, 2006 and 2016, respectively. The 6.875 percent and 7.125 percent notes are not redeemable prior to maturity. The 7.55 percent debentures are redeemable, at the option of the Company, at any time and at a price determinable at the time of redemption. Interest is payable semi-annually.

The 8.45 percent senior secured bonds represent securities issued by a subsidiary under a trust indenture dated July 20, 1999. These securities amortize semi-annually with final maturity in 2012 and are redeemable prior to maturity under certain circumstances. Such securities were issued in connection with the financing of the Company's share of the costs for the exploration and development of the Terra Nova oil field located off the East Coast of Canada. Interest is payable semi-annually. Although the Company commenced principal payments on August 1, 2001 ($8 million) it has the option of subsequently delaying the repayment schedule by one year. The Company, through a wholly owned partnership, owns 12.51 percent of the oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the oil field. There is also a charge created by the partnership on its interest in the assets of the oil field and associated facilities in favour of the security holders. In addition, certain financial obligations require letters of credit or cash equivalents as collateral.

The private placement notes are issued under two separate note agreements dated January 31, 2001. The notes are unsecured and redeemable at any time by the Company at a price determinable at the time of redemption. Interest is payable semi-annually or quarterly, depending on the particular note.

The medium-term notes Series B and C represent unsecured securities issued under a trust indenture dated February 3, 1997 and the Series D and E notes represent unsecured securities issued under a trust indenture dated May 4, 1999. The amounts, rates and maturities are as follows:

Issue	Amount	Interest Rate	Maturity Date
Series B	$100	6.85%	February 2007
Series C	100	5.75%	February 2003
Series D	200	6.30%	June 2004
Series E	200	6.95%	July 2009
	$600		

Interest is payable semi-annually on all series. The Series B and E notes are redeemable at any time at the option of the Company, at a price determinable at the time of redemption.

Aggregate maturities of long-term debt for the next five years are: 2003 — $421 million; 2004 — $272 million; 2005 — $74 million; 2006 — $276 million; and 2007 — $132 million.

Note 10
Income Taxes

The combined provisions for income taxes in the Consolidated Statements of Earnings and Retained Earnings (Deficit) reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

	2002	2001	2000
Earnings before taxes	$ 1,224	$ 1,074	$ 801
Statutory income tax rate (*percent*)	41.6	43.7	44.7
Expected income tax	509	469	358
Effect on income tax of:			
Change in statutory tax rate	(31)	(52)	—
Ownership charges	—	—	15
Return on capital securities	(11)	(18)	(16)
Royalties, lease rentals and mineral taxes payable to the crown	159	184	141
Resource allowance on Canadian production income	(212)	(219)	(175)
Non-deductible capital taxes	18	20	12
Gains and losses on foreign exchange	—	20	9
Other — net	(23)	(2)	3
	$ 409	$ 402	$ 347
Charged (credited) to:			
Income tax expense	$ 420	$ 420	$ 363
Retained earnings	(11)	(18)	(16)
	$ 409	$ 402	$ 347

The future income taxes liability at December 31 comprised the tax effect of temporary differences as follows:

	2002	2001	2000
Future tax liabilities			
Property, plant and equipment	$ 2,199	$ 1,882	$ 1,467
Other temporary differences	30	7	2
	2,229	1,889	1,469
Future tax assets			
Loss carryforwards	7	28	103
Foreign exchange losses deductible on realization	28	26	7
Site restoration and other deferred credits	105	93	81
Provincial royalty rebates	48	46	45
Other temporary differences	38	37	21
	226	230	257
	$ 2,003	$ 1,659	$ 1,212

Note 11
Share Capital

The Company's authorized share capital is as follows:

Common shares — an unlimited number of no par value.
Preferred shares — an unlimited number of no par value.

Changes to issued share capital were as follows:

Common Shares

	Number of Shares	Dollars
January 1, 2000	—	$ —
Issued for Renaissance shares	145,530,429	1,734
Issued for Husky Oil Limited shares	270,272,654	1,654
December 31, 2000	415,803,083	3,388
Options and warrants exercised	1,075,010	9
December 31, 2001	416,878,093	3,397
Options and warrants exercised	995,508	9
December 31, 2002	417,873,601	$ 3,406

Preferred Shares

In 2000, the Company issued 145.5 million preferred shares to former shareholders of Renaissance. These shares were subsequently redeemed for total proceeds of $364 million. At December 31, 2002, 2001 and 2000, there were no outstanding preferred shares.

Restructuring

As part of the restructuring that occurred in 2000, all previously issued preferred shares of Husky Oil Limited were exchanged, redeemed or cancelled on the capitalization of Husky Energy Inc. All previously issued common and preferred shares were recorded at a value of $1 per share. In addition, the previously outstanding subordinated shareholders' loans, which bore interest payable at 9.05 percent per annum, were converted to Class C preferred shares prior to their cancellation.

In August 2000, $150 million Class A preferred shares and $190 million Class B preferred shares were exchanged for $340 million of Husky Energy Inc. common shares. In addition, $1,306 million Class C preferred shares were cancelled on amalgamation for $1,306 million Husky Energy Inc. common shares. Husky Energy Inc. common shares issued for Husky Oil Limited shares as at December 31, 2000 were $1,654 million which included $8 million of paid in capital.

Stock Options

The following options to purchase common shares have been awarded to directors, officers and certain other employees. At December 31, 2002, 29.2 million common shares were reserved for issuance under the Company stock option plan. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

	Number of Shares (thousands)	Weighted Average Exercise Prices	Weighted Average Contractual Life (years)	Options Exercisable (thousands)
January 1, 2000	—	$ —	—	—
Granted	8,995	$ 13.61	5	
Assumed on Renaissance acquisition	1,372	$ 15.77	2	
Forfeited	(606)	$ 13.61	5	
December 31, 2000	9,761	$ 13.91	4	1,372
Granted	664	$ 15.60	4	
Exercised	(656)	$ 13.99	3	
Forfeited	(1,167)	$ 15.81	2	
December 31, 2001	8,602	$ 13.78	4	2,853
Granted	568	$ 16.11	5	
Exercised	(608)	$ 13.63	2	
Forfeited	(642)	$ 14.37	3	
December 31, 2002	7,920	$ 13.91	3	4,822

At December 31, 2002, the options outstanding had exercise prices ranging from $11.16 to $19.76.

In 2000, the Company granted 1.4 million Renaissance replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. The warrants are exercisable only if and when the Renaissance replacement options are exercised and provide for the issue of a maximum of 2.5 million common shares. As at December 31, 2002, there were 815 thousand common shares remaining which could potentially be issued as a result of the exercise of these warrants.

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

	2002	2001	2000
Weighted average fair market value per option	$ 5.19	$ 5.70	$ 5.03
Risk-free interest rate (*percent*)	3.6	3.5	5.5
Volatility (*percent*)	43	45	30
Expected life (*years*)	5	5	5
Expected annual dividend per share	$ 0.36	$ 0.36	$ 0.36

The Company follows the intrinsic value method of accounting for stock-based compensation for its fixed stock option plan, under which compensation cost is not recognized. If the Company applied the fair value method at the grant dates for options granted in 2002 and also to all options granted, the Company's net earnings and earnings per share would have been as follows:

	2002	2001	2000
Compensation cost — options granted in 2002	$ —	$ —	$ —
Compensation cost — all options granted	$ 13	$ 13	$ 4
Net earnings available to common shareholders			
As reported	$ 787	$ 620	$ 410
Options granted in 2002	$ 787	$ 620	$ 410
All options granted	$ 774	$ 607	$ 406
Weighted average number of common shares outstanding *(millions)*			
Basic	417.4	416.1	321.2
Diluted	419.3	418.6	321.2
Basic earnings per share			
As reported	$ 1.88	$ 1.49	$ 1.28
Options granted in 2002	$ 1.88	$ 1.49	$ 1.28
All options granted	$ 1.86	$ 1.46	$ 1.26
Diluted earnings per share			
As reported	$ 1.88	$ 1.48	$ 1.28
Options granted in 2002	$ 1.88	$ 1.48	$ 1.28
All options granted	$ 1.85	$ 1.45	$ 1.26

Per Share Amounts

The calculation of basic net earnings and cash flow from operations per common share is based on the net earnings and cash flow from operations after deducting return on capital securities, net of applicable income taxes, divided by the weighted average number of common shares outstanding.

Diluted net earnings and cash flow from operations per common share include the dilutive impact of options and warrants outstanding under the employee stock option plan calculated using the “treasury stock method”. Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings and cash flow from operations per common share, as the Company has neither the obligation nor intention to settle amounts due through the issue of shares.

The number of antidilutive options and warrants at December 31, 2002, 2001 and 2000 were nil, nil and 11.7 million, respectively.

During 2002 the Company declared dividends of $0.36 per common share (2001 — $0.36 per common share).

Note 12
Capital Securities

The Company issued U.S. $225 million unsecured capital securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. They yield an annual return of 8.9 percent, payable semi-annually until August 15, 2008 and mature in 2028. The capital securities are redeemable, in whole or in part, by the Company at any time prior to August 15, 2008 at a price determinable at the time of redemption. They are redeemable at par, in whole but not in part, by the Company on or after August 15, 2008. If not redeemed in whole, commencing on August 15, 2008, the annual return changes to a floating rate equal to U.S. LIBOR plus 5.50 percent payable semi-annually. The Company has the right at any time prior to maturity to defer payment of the return on the securities. Since the Company also has the unrestricted ability to settle its deferred return, principal and redemption obligations through the issuance of common or preferred shares, the principal amount of the capital securities, net of issue costs, has been classified as equity. The return amounts, net of

income taxes, are classified as distributions of equity. Return on capital securities comprises the return and foreign exchange on the capital securities.

The amounts disclosed as capital securities in shareholders' equity at December 31 were as follows:

	2002	2001	2000
Capital securities — *U.S. $225*	$ 355	$ 358	$ 338
Unamortized costs of issue	(3)	(3)	(5)
Accrued return	12	12	11
	$ 364	$ 367	$ 344

Note 13
Pension Plans and Other Post-retirement Benefits

The Company currently provides a defined contribution pension plan for all qualified employees. The Company also maintains a defined benefit pension plan, which is closed to new entrants, and all current participants are vested. The Company also provides certain medical and dental coverage to its retirees which are accrued over the working lives of the employees.

Weighted average long-term assumptions used for the defined benefit pension plan and other post-retirement benefits were as follows:

	2002	2001	2000
Discount rate *(percent)*	6.3	7.3	7.3
Long-term rate of increase in compensation levels *(percent)*	5.0	5.0	5.0
Long-term rate of return on plan assets *(percent)*	8.0	8.0	8.0

The status of the defined benefit plan and accrued benefit liability at December 31 were as follows:

	2002	2001	2000
Plan assets at fair market value, principally marketable debt and equity securities and cash equivalents	$ 77	$ 85	$ 90
Projected benefit obligation	(108)	(95)	(93)
Excess assets (excess obligation)	(31)	(10)	(3)
Unrecognized past service cost	1	—	—
Unrecognized (gains) losses	27	6	(2)
Accrued benefit liability	$ (3)	$ (4)	$ (5)

The Company's other post-retirement benefits program is not funded and at December 31, 2002, the obligation was $21 million, $17 million of which was accrued. The obligation and accrual at December 31, 2001 and 2000 was $16 million and $13 million, respectively. At December 31, 2002 the discount rate was changed to 6.3 percent from 7.3 percent.

Note 14
Commitments and Contingencies

Certain former owners of interests in the upgrading assets retained a 20-year upside financial interest expiring in 2014 which would require payments to them, should certain product price conditions be met.

The Company has firm commitments for transportation services that require the payment of tariffs. The Company has sufficient production to utilize these transmission services.

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, 2002 was $1.1 billion. As at December 31, 2002 the Company had spent $322 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.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time and management believes that it has adequately provided for current and future income taxes.

Note 15
Financial Instruments and Risk Management

The nature of the Company's operations, including the issuance of long-term debt, exposes the Company to fluctuations in commodity prices, foreign currency exchange rates and interest rates. The Company monitors these risks and, when appropriate, utilizes derivative financial instruments to manage its exposure to these risks. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes.

Carrying Values and Estimated Fair Values of Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of those instruments. The estimated fair values of other financial instruments at December 31 were as follows:

Assets (Liabilities)

	2002		2001		2000	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ (2,385)	$(2,579)	$ (2,092)	$(2,143)	$ (2,344)	$(2,348)
Foreign exchange contracts	—	(7)	—	(29)	—	(5)
Foreign exchange forwards	—	(5)	—	—	—	—
Interest rate swaps	—	86	—	4	—	5
Natural gas contracts	—	(4)	—	15	—	5
Crude oil contracts	—	6	—	—	—	—
Fixed physical sales contracts	—	111	—	114	—	—
Fixed physical purchase contracts	—	(122)	—	(88)	—	—

Upstream Commodity Price Risk

The Company, from time to time, employs financial and physical arrangements intended to manage its exposure to price fluctuations. The Company may use physical fixed price product arrangements, futures contracts, swaps, collars and put options to hedge its commodity prices. A portion of the upstream segment price risk may be managed through the forward selling of oil and gas production combined with the forward selling of U.S. dollars.

At December 31, 2002 the Company had hedged 7.5 mmcf of natural gas per day at NYMEX for the years 2003-2005 at an average price of U.S. $1.92 per mcf.

During 2002 the impact was insignificant (2001 — insignificant; 2000 — loss of $150 million) from upstream hedges.

Commodity Marketing Activities

The Company also uses commodity derivatives to manage price risk associated with marketing activities. Derivative instruments provide methods to meet customer pricing requirements while achieving a price structure consistent with the Company's overall pricing strategy. Under this

“brokering” strategy substantially all derivative transactions are concurrently offset by a physical purchase or sale arrangement that matches the volume, duration and sales point at which the transactions are priced. In this manner the Company is able either to fix a spread between the price paid to the third party producer and the price received from the financial counterparty or convert a fixed price to floating.

During 2002, the Company entered into variable price physical forward sales with respect to crude oil of 20,000 bbls per 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 that Husky received under financial transactions for October and November production was U.S. $30.51 per bbl and U.S. $30.18 per bbl, respectively. A gain of $5 million was recognized in 2002.

In December 2002 and January 2003 the Company entered into variable price physical forward sales with respect to crude oil of 20,000 bbls per day for January 2003, 30,000 bbls per day for February to May 2003 and 20,000 bbls per day for June 2003. The average fixed price Husky receives under the financial transactions for January is U.S. $30.41 per bbl, February and March U.S. $30.45 per bbl, April and May U.S. $30.38 per bbl and for June U.S. $30.30 per bbl. Also, the Company hedged 30 mmcf per day of natural gas for April to October 2003 at an average price of U.S. $5.04.

In addition, the Company has a portfolio of fixed price offsetting physical forward purchase and sale natural gas contracts. The objective of these contracts is to “lock in” a positive spread between the physical purchase and sales contract prices. At December 31, 2002 the Company had entered into offsetting fixed price physical arrangements to concurrently sell and purchase natural gas for 12 mmcf per day for 2003 through October 2004 to receive an average fixed margin of $0.24 per mcf. In addition, the Company had entered into fixed price physical forward sales with respect to natural gas inventory held in storage for 26 mmcf per day through April 2004 to receive an average fixed margin of $0.92 per mcf.

At December 31, 2002 the Company had also entered into a number of arrangements, consistent with the strategies described above, the impact of which is insignificant to the Company’s operations.

Foreign Currency Rate Risk

The Company manages its exposure to exchange rate fluctuations by balancing the U.S. denominated cash flows from operations with U.S. denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency. In addition, Husky has hedged a percentage of its exposure to fluctuations in the U.S. dollar with collar arrangements.

At December 31, 2002 the Company had hedged the exchange rate on U.S. dollars through currency collars up to U.S. $20 million per month at an average floor exchange rate of $1.49 and an average ceiling exchange rate of $1.54 for varying periods up to 2004.

During 2002 the Company realized a loss of $11 million (2001 — loss of $4 million; 2000 — loss of $5 million) from foreign currency risk management activities.

In January 2003, the Company used a currency swap to convert the 6.875 percent notes of U.S. $150 million due November 15, 2003 to Canadian $229 million. The exchange rate of the swap was $1.525 and will result in a foreign exchange gain of $8 million (before tax). The interest rate on the swap is 8.50 percent.

Foreign Exchange Forwards

The Company hedged U.S. dollar revenues for various amounts and maturities to 2005 through the use of foreign exchange forwards. The total amount hedged is U.S. $104 million at an average forward rate of $1.5576.

Interest Rate Risk

The majority of the Company’s long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2002 the Company had 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		Swap Maturity	Swap Rate (percent)
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 2002 the Company realized a gain of $29 million (2001 — gain of $2 million; 2000 — gain of $1 million) from interest rate risk management activities.

In January 2003, the Company unwound the interest rate swap on the 6.875 percent notes due November 15, 2003. The proceeds were U.S. $2 million and will be deferred and amortized into income during 2003.

Credit Risk

Accounts receivable are predominantly with customers in the energy industry and are subject to normal industry credit risks. In addition, the Company is exposed to credit related losses in the event of non-performance by counterparties to its financial instruments. The Company primarily deals with major financial institutions and investment grade rated entities to mitigate these risks.

Sale of Accounts Receivable

The Company has an agreement to sell net trade receivables 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 for 2002 was approximately 2.8 percent (2001 — 4.7 percent; 2000 — 6.0 percent). The Company has potential exposure to an immaterial amount of credit loss under this agreement.

Note 16
Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in some respects to those in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

Consolidated Statements of Earnings

	2002	2001	2000
Net earnings	$ 804	$ 654	$ 438
Adjustments			
Full cost accounting [(a)]	88	(544)	26
Related income taxes	(37)	235	(12)
Foreign currency translation on capital securities [(b)]	3	(20)	(13)
Related income taxes	(1)	5	4
Post-retirement benefits [(c)]	—	—	(4)
Related income taxes	—	—	2
Return on capital securities [(d)]	(32)	(33)	(30)
Related income taxes	11	14	13
Gain (loss) on energy trading contracts [(e)]	(2)	20	—
Related income taxes	1	(8)	—
Derivatives and hedging [(e)]	22	(20)	—
Related income taxes	(9)	8	—
Accounting for income taxes [(f)]	(37)	(14)	23
Net earnings under U.S. GAAP	$ 811	$ 297	$ 447
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
— Basic	417.4	416.1	321.2
— Diluted	419.3	418.6	321.2
Net earnings per share under U.S. GAAP — Basic	$ 1.94	$ 0.71	$ 1.39

— Diluted	$ 1.93	$ 0.71	$ 1.39

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

Condensed Consolidated Balance Sheets

	2002		2001		2000	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets [e]	$ 1,144	$ 1,292	$ 626	$ 756	$ 928	$ 939
Property, plant and equipment, net [a]	9,347	8,670	8,715	7,950	7,841	7,620
Other assets [b][d][j]	84	89	29	33	60	65
	$ 10,575	$10,051	$ 9,370	$ 8,739	$ 8,829	$ 8,624
Current liabilities [c][d][e][j]	$ 1,232	$ 1,318	$ 1,065	$ 1,203	$ 1,143	$ 1,165
Long-term debt [d][e]	1,964	2,406	1,948	2,306	2,311	2,648
Site restoration provision	249	249	212	212	178	178
Future income taxes [a][b][c][d][e][f][j]	2,003	1,772	1,659	1,361	1,212	1,135
Capital securities and accrued return [d]	364	—	367	—	344	—
Share capital and contributed surplus [g][h]	3,406	3,640	3,397	3,631	3,388	3,622
Accumulated other comprehensive income [e][j]	—	(17)	—	3	—	—
Retained earnings (deficit)	1,357	683	722	23	253	(124)
	$ 10,575	$10,051	$ 9,370	$ 8,739	$ 8,829	$ 8,624

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

Condensed Consolidated Statements of Retained Earnings (Deficit) and Comprehensive Income

	2002		2001		2000	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings (deficit), beginning of year	$ 722	$ 23	$ 253	$ (124)	$ (295)	$ (571)
Net earnings	804	811	654	297	438	447
Dividends on common shares and other	(151)	(151)	(150)	(150)	152	—
Capital securities, net of tax and foreign exchange [d]	(18)	—	(35)	—	(27)	—
Foreign exchange [b]	—	—	—	—	(15)	—
Retained earnings (deficit), end of year	$ 1,357	$ 683	$ 722	$ 23	$ 253	$ (124)
Other comprehensive income, beginning of year	$ —	$ 3	$ —	$ —	$ —	$ —
Cumulative effect of change in accounting, net of tax [e]	—	—	—	(10)	—	—
Cash flow hedges, net of tax [e]	—	(10)	—	13	—	—
Minimum pension liability, net of tax [j]	—	(10)	—	—	—	—
Other comprehensive income, end of year	$ —	$ (17)	$ —	$ 3	$ —	$ —

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

Condensed Consolidated Statements of Earnings

	2002		2001		2000	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues [e][i]	$ 6,384	$ 5,778	$ 6,596	$ 5,606	$ 5,066	$ 4,628
Costs and expenses [b][d][e][i]	4,117	3,488	4,614	3,654	3,683	3,263
Depletion, depreciation and amortization [a]	939	851	807	1,351	481	455
Interest, net [d]	104	136	101	134	101	131
Earnings before income taxes	1,224	1,303	1,074	467	801	779
Income taxes [a][b][c][d][e][f]	420	492	420	176	363	332
Net earnings, before cumulative effect of change in accounting	804	811	654	291	438	447
Change in accounting, net of tax [e]	—	—	—	6	—	—
Net earnings	$ 804	$ 811	$ 654	$ 297	$ 438	$ 447

2001 and 2000 amounts as restated (notes 3 and 16 (b)).

The increases or decreases noted above refer to the following differences between U.S. GAAP and Canadian GAAP:

(a) The Company performs a cost recovery ceiling test for each cost centre which limits net capitalized costs to the undiscounted estimated future net revenue from proved oil and gas reserves plus the cost of unproved properties less impairment, using year-end prices or average prices in that year if appropriate. In addition, the aggregate value of all cost centres is further limited by including financing costs, administration expenses, future removal and site restoration costs and income taxes. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount factor of 10 percent. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. Financing and administration costs are excluded from the calculation under U.S. GAAP. At December 31, 2001 the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax.

(b) Effective January 1, 2002, the Company retroactively adopted the revised recommendations of the CICA on Foreign Currency Translation (note 3). The new recommendations eliminated the deferral and amortization of foreign exchange gains and losses on long-term monetary items. The Company records the gain or loss on the capital securities as a charge to retained earnings. Under U.S. GAAP, gains or losses on translation of foreign denominated long-term monetary items, including those on capital securities, are credited or charged to earnings immediately.

(c) Prior to 2000 the Company expensed costs related to medical and dental post-retirement benefits as incurred. Effective January 1, 2000 the Company retroactively adopted, without restatement, the new recommendations issued by the CICA on accounting for employee future benefits which are consistent with those under U.S. GAAP, which requires use of the projected benefit method prorated based on service.

(d) The Company records the capital securities as a component of equity and the return thereon as a charge to retained earnings. Under U.S. GAAP, the capital securities, the accrued return thereon and costs of issue would be classified outside of shareholders' equity and the related return would be charged to earnings.

(e) Effective January 1, 2001, the Company adopted the provisions of FAS 133, "Accounting for Derivative Instruments and Hedging Activities". On initial adoption of FAS 133, the Company recorded additional assets and liabilities of $20.3 million and $10.0 million, respectively, and a resulting cumulative catch-up adjustment to increase earnings by $5.7 million, net of tax, for the fair value of derivatives which did not qualify as hedges on January 1, 2001. The Company also recorded assets and liabilities of $3.8 million and $23.0 million, respectively, and a resulting reduction of other comprehensive income within shareholders' equity of $10.6 million, net of tax, for the fair value of derivatives designated as hedges against variability in future cash flows from the sale of natural gas. An additional asset of $7.4 million for the fair value of derivatives designated as hedges against changes in the fair value of certain firm commitments and an offsetting liability for the difference

between carrying and fair values of the hedged items was also recorded. The effect of the cumulative catch-up adjustment was to increase net earnings per share under U.S. GAAP by $0.01 (basic and diluted).

At December 31, 2002 the Company recorded additional assets and liabilities for U.S. GAAP purposes of $110.6 million and $122.1 million, respectively, for the fair values of derivative financial instruments. During 2002, a gain of $11.0 million, net of tax, was included in income for U.S. GAAP purposes for unrealized gains on foreign currency derivatives and natural gas basis swaps that did not qualify for hedge accounting under FAS 133. The Company also recorded a gain of $1.3 million, net of tax, in revenue for U.S. GAAP purposes with respect to derivatives designated as hedges of change in the fair value of certain fixed price commodity contracts and offsetting changes in the fair value of those contracts. In addition, the amount included in other comprehensive income was adjusted by a $10.1 million gain, net of tax, for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk, foreign exchange derivatives and the transfer to income of amounts applicable to cash flows occurring in 2002.

Under U.S. GAAP, energy trading contracts entered into and physical energy trading inventories purchased on or before October 26, 2002 have been recorded at fair value. These contracts include derivatives as well as energy trading contracts that do not meet the definition of derivatives. Effective October 26, 2002, non-derivative energy trading contracts and inventories purchased after the effective date are no longer recorded at fair value in accordance with Emerging Issues Task Force ("EITF") 02-03 "Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities". Under Canadian GAAP, the impact of energy trading contracts is recorded as they settle. Under U.S. GAAP, the Company recorded additional assets and liabilities of $37.0 million and $19.3 million, respectively, at December 31, 2002 and included the resulting unrealized gain in earnings for the year.

Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues. All prior periods have been reclassified to conform with this change.

(f) The Canadian GAAP liability method of accounting for income taxes requires the measurement of future income tax liabilities and assets using income tax rates that reflect enacted income tax rate reductions, provided it is more likely than not that the Company will be eligible for such rate reductions in the period of reversal. U.S. GAAP allows recording of such rate reductions only when claimed.

(g) As a result of the reorganization of the capital structure which occurred on August 25, 2000, the deficit of Husky Oil Limited was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(h) The Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(i) Under U.S. GAAP, transportation costs are included in cost of sales rather than netted against sales and operating revenues. Transportation costs for 2002 were $256 million (2001 — $272 million; 2000 — $159 million).

(j) The Company amortizes the portion of the unrecognized gains or losses that exceed 10 percent of the greater of the projected benefit obligation or the market-related value of pension plan assets. The market-related value of the pension plan assets is either the fair value or a calculated value that recognizes changes in fair value over not more than five years. Under U.S. GAAP, an additional minimum liability is recognized if the unfunded accumulated benefit obligation exceeds the unfunded pension cost already recognized. If an additional minimum liability is recognized, an amount equal to the unrecognized prior service cost is recognized as an intangible asset and any excess is reported in other comprehensive income.

Additional U.S. GAAP Disclosures

FAS 133

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which require that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value. Gains or losses, including unrealized amounts, on derivatives that have not been designated as hedges, or were not effective as hedges, are included in earnings as they arise.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with equal or lesser amounts of changes in the fair value of the hedged item. During 2002, no amount of the gains or losses on these derivatives was excluded from the assessment of hedge effectiveness in these hedging relationships.

For derivatives designated as cash flow hedges, changes in the fair value of the derivatives are recognized in other comprehensive income until the hedged items are recognized in earnings. Any portion of the change in the fair value of the derivatives that is not effective in hedging the changes in future cash flows is included in earnings. The amount related to the hedge of commodity price risk was included in other comprehensive income at December 31, 2002. During 2002, no amounts were excluded from the assessment of effectiveness of the cash flow hedges.

Stock Option Plan

FAS 123, "Accounting for Stock-based Compensation", establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by FAS 123, Husky has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25. Since all options were granted with exercise prices equal to the market price when the options were granted, no compensation expense has been charged to income at the time of the option grants. Had compensation cost for Husky's stock options been determined based on the fair market value at the grant dates of the awards, and amortized on a straight-line basis, consistent with methodology prescribed by FAS 123, Husky's net earnings and net earnings per share for the years ended December 31, 2002, 2001 and 2000 would have been the pro forma amounts indicated below:

		2002		2001		2000	
		As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net earnings		$ 811	$ 798	$ 297	$ 284	$ 447	$ 443
Net earnings per share	— Basic	$ 1.94	$ 1.91	$ 0.71	$ 0.68	$ 1.39	$ 1.38
	— Diluted	$ 1.93	$ 1.90	$ 0.71	$ 0.68	$ 1.39	$ 1.38

The fair values of all common share options granted are estimated on the date of grant using the Modified Black-Scholes option-pricing model. The weighted average fair market value of options granted during the year and the assumptions used in their determination are the same as note 11.

Depletion, Depreciation and Amortization

Upstream depletion, depreciation and amortization, per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent ("boe") using the ratio of 6 mcf of natural gas to 1 barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion, depreciation and amortization per boe for the years ended December 31 were as follows:

	2002	2001	2000
Depletion, depreciation and amortization per boe [(1)]	$ 6.96	$ 6.88	$ 5.88

(1) Excludes the 2001 ceiling test write down.

Impairment or Disposal of Long-term Assets

In August 2001, the FASB issued FAS 144 "Accounting for the Impairment or Disposal of Long-term Assets", which addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. FAS 144 supersedes but retains the basic principles of FASB Statement No. 121 for the impairment of assets to be held and used. A two-step process is used to determine the impairment of the Company's long-term assets, other than assets covered by the full cost accounting policy, with the first step determining when impairment is recognized and the second step measuring the amount of the impairment. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived asset's carrying value exceeds its fair value. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The

results of operations of a component of an entity that has been disposed of, or is classified as held for sale, is reported in discontinued operations if:

(a) The operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction, and;

(b) The entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

A component of an entity comprises operations and cash flows that can be clearly distinguished, operationally and for financial reporting purposes, from the rest of the enterprise. A component may be a reportable segment or an operating segment, a reporting unit, a subsidiary or an asset group.

This standard was adopted prospectively on January 1, 2002. It did not result in any differences between Canadian and U.S. GAAP in 2002.

Accounting for Guarantees

In November 2002, the FASB issued Financial Interpretation 45 “Accounting for Guarantees” (“FIN 45”) that will require the recognition of a liability for the fair value of certain guarantees that require payments contingent on specified types of future events. The measurement standards of FIN 45 are applicable to guarantees entered into after January 1, 2003. For guarantees that existed as at December 31, 2002, FIN 45 requires additional disclosures which have been included in these financial statements to the extent applicable to the Company.

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation 46 “Accounting for Variable Interest Entities” (“FIN 46”) that will require the consolidation of certain entities that are controlled through financial interests that indicate control (referred to as “variable interests”). Variable interests are the rights or obligations that convey economic gains or losses from changes in the values of the entity’s assets or liabilities. The holder of the majority of an entity’s variable interests will be required to consolidate the variable interest entity. The Company does not believe FIN 46 will result in the consolidation of any additional entities that existed at December 31, 2002.

Future Removal and Site Restoration

In June 2001, the FASB issued Statement No. 143 “Accounting for Asset Retirement Obligations” (“FAS 143”), which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and use of the asset. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset. The liability is accreted at the end of each period through charges to operating expenses. The Company is required and plans to adopt the provisions of FAS 143 for the quarter ending March 31, 2003. The change will result in an increase to net property, plant and equipment of $56 million, an increase in future removal and site restoration liability of $58 million, a decrease to the future tax liability of $1 million and a decrease to retained earnings of $1 million.

SUPPLEMENTAL FINANCIAL AND OPERATING INFORMATION

Oil and Gas Producing Activities (unaudited)

The following disclosures have been prepared in accordance with FASB Statement No. 69 "Disclosures about Oil and Gas Producing Activities" ("FAS 69"):

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Company's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Company's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2002 no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Results of Operations for Producing Activities

The following table sets forth revenue and direct cost information relating to the Company's oil and gas producing activities for the years ended December 31:

Results of Operations

	Canada[1]			International [1]			Total[1]		
($ millions)	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenue									
Sales	$1,738	$1,771	$1,158	$ 190	$ 4	$ 4	$1,928	$1,775	$1,162
Transfers	737	390	387	—	—	—	737	390	387
	2,475	2,161	1,545	190	4	4	2,665	2,165	1,549
Deduct									
Production costs	676	617	345	10	—	1	686	617	346
Depletion, depreciation and amortization	813	721	398	38	7	9	851	728	407
Income taxes	387	334	326	64	(1)	(3)	451	333	323
	1,876	1,672	1,069	112	6	7	1,988	1,678	1,076
Results of operations from producing activities	$ 599	$ 489	$ 476	$ 78	$ (2)	$ (3)	$ 677	$ 487	$ 473

Depletion, depreciation and amortization rates per gross equivalent barrel	$ 7.74	$ 7.24	$ 6.15	$8.33	$80.61	$90.39	$ 7.76	$ 7.31	$ 6.28

(1) The costs in this schedule exclude corporate overhead, interest expense and other operating costs which are not directly related to producing activities.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Capitalized costs incurred in oil and gas producing activities for the years ended December 31 were as follows:

Costs Incurred

($ millions)		2002	2001	2000
Property acquisition costs[1][2][3]				
Proved	— Canada	$ 20	$ 366	$ 3,200
Unproved	— Canada	88	55	355
		108	421	3,555
Exploration costs	— Canada	257	262	159
	— Other	9	5	3
		266	267	162
Development costs	— Canada	1,127	774	412
	— China	66	99	85
		1,193	873	497
		$ 1,567	$ 1,561	$ 4,214

(1) *Property acquisition costs related to corporate acquisitions for proved properties in 2002 were nil; 2001 included $244 million.*

(2) *Property acquisition costs in 2000 included $3,181 million for proved properties and $333 million for unproved properties related to the acquisition of Renaissance.*

(3) *Property acquisition costs in 2000 excluded $135 million for proved properties and $19 million for unproved properties related to property exchanges.*

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Exploration costs include the costs of geological and geophysical activity, retaining undeveloped properties and drilling and equipping exploration wells.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas.

Exploration and development costs include administrative costs and depreciation of support equipment directly associated with these activities.

The following table sets forth a summary of oil and gas property costs not being amortized at December 31:

Withheld Costs

($ millions)		Total	2002	2001	2000	Prior to 2000
Property acquisition	— Canada	$ 414	$ 37	$ 17	$ 251	$ 109
	— International	14	—	—	—	14
		428	37	17	251	123
Exploration	— Canada	271	79	57	48	87
	— International	6	6	—	—	—

		277	85	57	48	135
Development	— Canada	487	392	83	12	—
	— International	17	1	—	—	16
		504	393	83	12	16
Capitalized interest	— Canada	146	26	51	43	26
		$ 1,355	$ 541	$ 208	$ 354	$ 252

Capitalized Costs Relating to Oil and Gas Producing Activities

The capitalized costs and related accumulated depletion, depreciation and amortization, including impairments, relating to the Company's oil and gas exploration, development and producing activities at December 31 consisted of:

Capitalized Costs

($ millions)		2002	2001[1]	2000[1]
Unproved oil and gas properties	— Canada	$ 1,318	$ 1,052	$ 951
	— International	37	235	137
		1,355	1,287	1,088
Proved oil and gas properties	— Canada	10,207	9,301	8,072
	— International	432	159	153
		10,639	9,460	8,225
		11,994	10,747	9,313
Less accumulated depletion, depreciation and amortization	— Canada	3,894	3,272	2,622
	— International	185	147	139
		4,079	3,419	2,761
		$ 7,915	$ 7,328	$ 6,552
Net capitalized costs	— Canada	$ 7,631	$ 7,081	$ 6,401
	— International	284	247	151
		$ 7,915	$ 7,328	$ 6,552

(1) *Capital related to 17 mmbbls of proved reserves at Terra Nova transferred to proved oil and gas properties. Terra Nova is a major development project off the East Coast of Canada.*

Oil and Gas Reserve Information

In Canada, the Company's proved crude oil, natural gas liquids, natural gas and sulphur reserves are located in the provinces of Alberta, Saskatchewan and British Columbia, and offshore the East Coast. The Company's international proved reserves are located in Indonesia, China and Libya. The Company's proved developed and undeveloped reserves after deductions of royalties are summarized below:

Reserves

	Canada			International			Total	
	Crude Oil & NGL	Natural Gas	Sulphur	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Sulphur
Net proved developed and undeveloped reserves, after royalties[(1)(2)(3)(4)]	(mmbbls)	(bcf)	(mmlt)	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmlt)
End of year 1999	212.1	771.7	5.0	5.9	110.5	218.0	882.2	5.0
Revisions	12.9	(59.1)	—	(0.1)	(0.4)	12.8	(59.5)	—
Purchases	215.6	789.0	—	—	—	215.6	789.0	—
Discoveries and extensions	41.5	35.4	—	29.4	—	70.9	35.4	—
Production	(36.6)	(102.4)	(0.3)	(0.1)	—	(36.7)	(102.4)	(0.3)
End of year 2000	445.5	1,434.6	4.7	35.1	110.1	480.6	1,544.7	4.7
Revisions	37.0	74.0	0.1	0.7	5.1	37.7	79.1	0.1
Purchases	33.6	20.4	—	—	—	33.6	20.4	—
Sales	(1.6)	(18.4)	—	—	—	(1.6)	(18.4)	—
Discoveries and extensions	44.8	200.1	0.1	1.1	—	45.9	200.1	0.1
Production	(56.3)	(152.1)	(0.2)	(0.1)	—	(56.4)	(152.1)	(0.2)
End of year 2001	503.0	1,558.6	4.7	36.8	115.2	539.8	1,673.8	4.7
Revisions	—	14.7	0.3	(0.8)	(14.3)	(0.8)	0.4	0.3
Purchases	4.2	5.4	—	—	—	4.2	5.4	—
Sales	(14.5)	(16.6)	—	—	—	(14.5)	(16.6)	—
Discoveries and extensions	37.2	205.4	—	1.1	—	38.3	205.4	—
Production	(61.8)	(155.7)	(0.4)	(4.3)	—	(66.1)	(155.7)	(0.4)
End of year 2002	468.1	1,611.8	4.6	32.8	100.9	500.9	1,712.7	4.6
Net proved developed reserves, after royalties[(1)(2)(3)(4)]								
End of year 1999	161.8	669.3	4.8	0.6	—	162.4	669.3	4.8
End of year 2000	345.2	1,275.5	4.5	0.5	—	345.7	1,275.5	4.5
End of year 2001	378.1	1,342.2	4.6	0.6	—	378.7	1,342.2	4.6
End of year 2002	360.9	1,272.8	3.7	28.2	—	389.1	1,272.8	3.7

(1) *Net reserves are the Company's lessor royalty, overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.*

(2) *Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations from a given date forward, by known technology, under existing operating conditions and prices in effect at year-end.*

(3) *Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.*

(4) *Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.*

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures prescribed by FAS 69 and based on crude oil and natural gas reserve and production volumes estimated by the engineering staff of the Company. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's reserves.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2002 was based on the NYMEX year-end natural gas spot price of U.S. $4.60/mmbtu (2001 — U.S. $2.75/mmbtu; 2000 — U.S. $10.53/mmbtu) and on crude oil prices computed with reference to the year-end West Texas Intermediate price of U.S. $31.21/bbl (2001 — U.S. $19.96/bbl; 2000 — U.S. $26.72/bbl).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (continued)

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's crude oil and natural gas reserves at December 31, for the years presented.

Standardized Measure

	Canada[1]			International[1]			Total[1]		
($ millions)	2002	2001	2000	2002	2001	2000	2002	2001	2000
Future cash inflows	$25,830	$14,102	$23,701	$2,719	$1,600	$1,787	$28,549	$15,702	$25,488
Future costs									
Future production and development costs	7,239	7,541	5,996	502	523	609	7,741	8,064	6,605
Future income taxes	7,278	2,540	7,384	860	310	402	8,138	2,850	7,786
Future net cash flows	11,313	4,021	10,321	1,357	767	776	12,670	4,788	11,097
Deduct 10% annual discount factor	4,966	1,667	4,859	518	329	404	5,484	1,996	5,263
Standardized measure of discounted future net cash flows	$ 6,347	$ 2,354	$ 5,462	$ 839	$ 438	$ 372	$ 7,186	$ 2,792	$ 5,834

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for the years presented.

Changes in Standardized Measure

	Canada[1]			International[1]			Total[1]		
($ millions)	2002	2001	2000	2002	2001	2000	2002	2001	2000
Present value at January 1	$ 2,354	$ 5,462	$ 1,612	$ 438	$ 372	$ 72	$ 2,792	$ 5,834	$ 1,684
Sales and transfers, net of production costs	(1,802)	(1,556)	(1,204)	(179)	(2)	(3)	(1,981)	(1,558)	(1,207)
Net change in sales and transfer prices, net of development and production costs	7,752	(5,843)	2,159	732	(48)	18	8,484	(5,891)	2,177
Extensions, discoveries and improved recovery, net of related costs	676	356	460	40	17	410	716	373	870
Revisions of quantity estimates	(30)	237	46	(28)	10	(2)	(58)	247	44
Accretion of discount	390	949	279	59	55	13	449	1,004	292
Sale of reserves in place	(189)	(6)	(3)	—	—	—	(189)	(6)	(3)
Purchase of reserves in place	45	174	5,681	—	—	—	45	174	5,681
Changes in timing of future net cash flows and other	(191)	95	(717)	80	10	3	(111)	105	(714)
Net change in income taxes	(2,658)	2,486	(2,851)	(303)	24	(139)	(2,961)	2,510	(2,990)
Present value at December 31	$ 6,347	$ 2,354	$ 5,462	$ 839	$ 438	$ 372	$ 7,186	$ 2,792	$ 5,834

(1) *The schedules above are calculated using year-end prices, costs, statutory income tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.*

Reserve Information

Reserve Reconciliation

	Canada				International			
	Western Canada			East Coast			Total	
	Light/Med. Crude Oil & NGL	Lloydminster Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
Proved reserves, before royalties[1]	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(bcf)
Proved reserves at December 31, 1999	138.3	105.0	933.9	—	7.0	142..9	250.3	1,076.8
Revisions	3.6	6.6	(17.2)	—	—	—	10.2	(17.2)
Purchases (includes Renaissance)	258.5	0.3	933.4	—	—	—	258.8	933.4
Discoveries, extensions and improved recovery	12.7	21.4	47.0	11.3	32.2	—	77.6	47.0
Production	(23.2)	(19.6)	(131.0)	—	(0.1)	—	(42.9)	(131.0)
Proved reserves at December 31, 2000	389.9	113.7	1,766.1	11.3	39.1	142.9	554.0	1,909.0
Revisions	0.8	24.9	22.5	1.2	0.2	—	27.1	22.5
Purchases	11.9	23.7	23.7	—	—	—	35.6	23.7
Sales	(1.8)	—	(21.1)	—	—	—	(1.8)	(21.1)
Discoveries, extensions and improved recovery	13.3	30.0	240.7	4.8	1.2	—	49.3	240.7
Production	(41.5)	(23.2)	(209.0)	—	(0.1)	—	(64.8)	(209.0)
Proved reserves at December 31, 2001	372.6	169.1	1,822.9	17.3	40.4	142.9	599.4	1,965.8
Revisions	(6.5)	18.4	(37.2)	—	—	—	11.9	(37.2)
Purchases	0.5	4.4	6.2	—	—	—	4.9	6.2
Sales	(16.4)	—	(19.0)	—	—	—	(16.4)	(19.0)
Discoveries, extensions and improved recovery	6.9	17.8	386.5	18.5	1.2	—	44.4	386.5
Production	(36.7)	(29.0)	(207.8)	(4.8)	(4.5)	—	(75.0)	(207.8)
Proved reserves at December 31, 2002	320.4	180.7	1,951.6	31.0	37.1	142.9	569.2	2,094.5
Proved developed reserves, before royalties[2]								
December 31, 1999	132.2	56.4	817.6	—	0.6	—	189.2	817.6
December 31, 2000	337.8	64.8	1,579.9	—	0.5	—	403.1	1,579.9
December 31, 2001	322.5	95.8	1,576.5	6.2	0.6	—	425.1	1,576.5
December 31, 2002	284.5	116.3	1,546.5	7.4	30.7	—	438.9	1,546.5
Probable reserves, before royalties[3]								
December 31, 1999	64.6	78.0	235.9	256.3	0.9	18.9	399.8	254.8
December 31, 2000	135.2	78.1	434.1	202.3	5.3	18.9	420.9	453.0
December 31, 2001	131.8	81.2	405.6	213.3	4.2	18.9	430.5	424.5
December 31, 2002	161.0	85.5	383.9	201.6	4.1	18.9	452.2	402.8

(1) *Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.*

(2) *Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.*

(3) *Probable reserves are considered to be those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which may reasonably be deemed proven at the present time, or*

those reserves which may reasonably be assumed to exist because of geophysical or geological indications and drilling done in regions which contain proved reserves. The risk associated with those reserves generally ranges from 40 to 80 percent.

Quarterly Financial and Operating Information

SEGMENTED OPERATIONAL INFORMATION

Upstream

		2002				2001			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Daily production, before royalties									
Light/medium crude oil & NGL *(mbbls/day)*		137.8	131.4	116.6	117.5	111.3	112.7	108.6	115.5
Lloydminster heavy crude oil *(mbbls/day)*		83.9	80.0	76.9	76.9	75.0	69.1	60.3	56.9
		221.7	211.4	193.5	194.4	186.3	181.8	168.9	172.4
Natural gas *(mmcf/day)*		577.4	561.6	571.8	566.0	568.7	567.1	570.8	584.0
Total production *(mboe/day)*		317.9	305.1	288.9	288.7	281.1	276.3	264.0	269.7
Average realized sales prices									
Light/medium crude oil & NGL *($/bbl)*		$36.64	$36.72	$32.42	$26.17	$19.44	$31.74	$28.86	$28.72
Lloydminster heavy crude oil *($/bbl)*		$25.47	$30.94	$27.02	$20.68	$10.44	$23.65	$15.52	$13.81
Natural gas *($/mcf)*		$ 4.76	$ 3.42	$ 3.98	$ 3.10	$ 3.01	$ 3.25	$ 6.57	$ 9.05
Operating costs *($/boe)*		$ 6.66	$ 6.19	$ 6.19	$ 5.88	$ 6.54	$ 6.24	$ 6.19	$ 5.31
Operating netbacks[1]									
Light/medium crude oil & NGL *($/boe)*		$24.29	$23.74	$20.40	$15.19	$ 7.43	$18.03	$17.01	$18.09
Lloydminster heavy crude oil *($/boe)*		$13.22	$20.63	$17.81	$12.46	$ 3.29	$14.04	$ 6.08	$ 4.87
Natural gas *($/mcfge)*		$ 3.18	$ 2.19	$ 2.39	$ 2.03	$ 1.74	$ 1.99	$ 4.28	$ 6.05
Total *($/boe)*		$19.71	$19.67	$17.67	$13.47	$ 7.34	$14.88	$17.62	$21.97
Net wells drilled[2]									
Exploration	Oil	3	6	6	5	8	8	15	45
	Gas	14	16	18	83	6	11	5	68
	Dry	2	2	1	9	4	2	3	25
		19	24	25	97	18	21	23	138
Development	Oil	107	190	112	44	116	195	129	102
	Gas	160	67	10	216	53	57	17	94
	Dry	17	14	6	18	11	23	7	22
		284	271	128	278	180	275	153	218
		303	295	153	375	198	296	176	356
Success ratio *(percent)*		94	95	95	93	92	92	95	87

Midstream

	2002				2001			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Synthetic crude oil sales *(mbbls/day)*	67.5	47.3	51.3	71.2	49.7	66.5	65.6	56.2
Upgrading differential *($/bbl)*	$13.06	$9.92	$10.43	$9.85	$16.85	$13.18	$19.56	$21.61
Pipeline throughput *(mbbls/day)*	476	436	448	469	518	498	583	550

Refined Products

	2002				2001			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Refined product sales volumes								

Light oil products *(million litres/day)*	7.9	8.2	7.4	7.2	7.5	8.2	7.3	7.4
Asphalt products *(mbbls/day)*	14.2	30.6	20.5	17.7	19.9	29.9	20.6	15.0
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	17.8	25.2	19.9	25.2	25.8	26.1	20.5	22.2
Prince George refinery *(mbbls/day)*	10.9	11.0	7.7	10.9	10.2	8.8	10.7	10.9
Refinery utilization *(percent)*	82	103	79	103	103	100	89	95

(1) Operating netbacks are Husky's average realized prices less royalties, hedging (gains)/losses and operating costs on a per unit basis.

(2) Western Canada.

Segmented Financial Information
($ millions)

	Upstream				Midstream							
					Upgrading				Infrastructure and Marketing			
2002	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Sales and operating revenues, net of royalties	$ 781	$ 738	$ 635	$ 511	$ 301	$ 192	$ 195	$ 221	$1,367	$ 953	$ 958	$ 952
Costs and expenses												
Operating, cost of sales, selling and general	206	189	171	163	265	183	182	181	1,321	905	916	896
Depletion, depreciation and amortization	231	218	202	200	5	4	4	5	6	5	5	4
Interest — net	—	—	—	—	—	—	—	—	—	—	—	—
Foreign exchange	—	—	—	—	—	—	—	—	—	—	—	—
	437	407	373	363	270	187	186	186	1,327	910	921	900
Earnings (loss) before income taxes	344	331	262	148	31	5	9	35	40	43	37	52
Current income taxes	26	8	1	20	—	1	—	—	(19)	13	4	8
Future income taxes	108	117	83	34	11	2	2	10	31	5	10	13
Net earnings (loss)	$ 210	$ 206	$ 178	$ 94	$ 20	$ 2	$ 7	$ 25	$ 28	$ 25	$ 23	$ 31
Capital employed [2]	$6,040	$6,027	$6,001	$5,919	$ 319	$ 343	$ 324	$ 306	$ 431	$ 428	$ 194	$ 268
Total assets	$8,220	$8,105	$7,860	$7,723	$ 658	$ 665	$ 657	$ 640	$ 850	$ 871	$ 736	$ 845

	Upstream				Midstream							
					Upgrading				Infrastructure and Marketing			
2001	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Sales and operating revenues, net of royalties	$ 367	$ 549	$ 578	$ 671	$ 147	$ 255	$ 259	$ 225	$1,153	$ 796	$ 839	$1,592
Costs and expenses												
Operating, cost of sales, selling and general	182	171	160	135	81	215	176	166	1,111	758	785	1,539
Depletion, depreciation and amortization	193	185	176	174	4	5	5	3	4	5	4	4
Interest — net	—	—	—	—	—	—	—	—	—	—	—	—
Foreign exchange	—	—	—	—	—	—	—	—	—	—	—	—
	375	356	336	309	85	220	181	169	1,115	763	789	1,543
Earnings (loss) before income taxes	(8)	193	242	362	62	35	78	56	38	33	50	49
Current income taxes	3	5	5	4	1	—	—	—	—	1	—	—
Future income taxes	3	79	60	148	21	13	18	20	16	14	20	21
Net earnings (loss)	$ (14)	$ 109	$ 177	$ 210	$ 40	$ 22	$ 60	$ 36	$ 22	$ 18	$ 30	$ 28

Capital employed [2]	$5,715	$5,685	$5,633	$5,444	$ 320	$ 303	$ 313	$ 337	$ 395	$ 373	$ 275	$ 254
Total assets	$7,407	$7,298	$7,104	$7,051	$ 644	$ 610	$ 610	$ 620	$ 862	$ 853	$ 835	$ 822

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

(2) Capital employed is defined as short- and long-term debt and shareholders' equity.

Segmented Financial Information
($ millions)

2002	Refined Products				Corporate and Eliminations[1]				Total			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Sales and operating revenues, net of royalties	$326	$431	$322	$231	$(1,078)	$(645)	$(451)	$(556)	$ 1,697	$ 1,669	$1,659	$1,359
Costs and expenses												
Operating, cost of sales, selling and general	318	395	292	217	(1,081)	(642)	(436)	(537)	1,029	1,030	1,125	920
Depletion, depreciation and amortization	9	9	8	8	5	3	4	4	256	239	223	221
Interest — net	—	—	—	—	25	28	24	27	25	28	24	27
Foreign exchange	—	—	—	—	(5)	75	(65)	8	(5)	75	(65)	8
	327	404	300	225	(1,056)	(536)	(473)	(498)	1,305	1,372	1,307	1,176
Earnings (loss) before income taxes	(1)	27	22	6	(22)	(109)	22	(58)	392	297	352	183
Current income taxes	(1)	4	1	—	—	—	—	—	6	26	6	28
Future income taxes	1	7	8	2	(7)	(33)	(20)	(30)	144	98	83	29
Net earnings (loss)	$ (1)	$ 16	$ 13	$ 4	$ (15)	$ (76)	$ 42	$ (28)	$ 242	$ 173	$ 263	$ 126
Capital employed[2]	$338	$360	$383	$375	$ 384	$ 176	$ 233	$ (2)	$ 7,512	$ 7,334	$7,135	$6,866
Total assets	$534	$554	$523	$516	$ 313	$ 153	$ 189	$ 6	$10,575	$10,348	$9,965	$9,730

2001	Refined Products				Corporate and Eliminations[1]				Total			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Sales and operating revenues, net of royalties	$274	$429	$345	$301	$(326)	$(559)	$(290)	$(1,009)	$1,615	$1,470	$1,731	$1,780
Costs and expenses												
Operating, cost of sales, selling and general	254	371	296	285	(330)	(552)	(283)	(1,000)	1,298	963	1,134	1,125
Depletion, depreciation and amortization	9	7	7	8	4	3	4	3	214	205	196	192
Interest — net	—	—	—	—	23	24	26	28	23	24	26	28
Foreign exchange	—	—	—	—	15	56	(50)	73	15	56	(50)	73
	263	378	303	293	(288)	(469)	(303)	(896)	1,550	1,248	1,306	1,418
Earnings (loss) before income taxes	11	51	42	8	(38)	(90)	13	(113)	65	222	425	362
Current income taxes	1	—	—	—	—	(1)	—	1	5	5	5	5
Future income taxes	7	21	16	4	(32)	(28)	7	(28)	15	99	121	165
Net earnings (loss)	$ 3	$ 30	$ 26	$ 4	$ (6)	$ (61)	$ 6	$ (86)	$ 45	$ 118	$ 299	$ 192
Capital employed[2]	$329	$304	$342	$364	$ (81)	$ (78)	$(103)	$ (96)	$6,678	$6,587	$6,460	$6,303
Total assets	$428	$491	$499	$498	$ 29	$ 10	$ (4)	$ —	$9,370	$9,262	$9,044	$8,991

Segmented Financial Information
($ millions)

	2002				2001			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Capital expenditures								
Upstream — Western Canada	$ 326	$ 207	$ 156	$ 345	$ 264	$ 323	$ 186	$ 249
— East Coast Canada	97	169	154	38	54	43	54	40
— International	8	25	22	20	35	21	18	30
	431	401	332	403	353	387	258	319
Midstream — Upgrader	11	9	12	9	37	5	3	2
— Infrastructure and marketing	5	2	3	7	22	6	5	25
	16	11	15	16	59	11	8	27
Refined products	22	9	9	4	12	7	5	5
Corporate	10	5	5	3	11	9	2	—
	$ 479	$ 426	$ 361	$ 426	$ 435	$ 414	$ 273	$ 351

Five-Year Financial and Operating Summary

Segmented Financial Information
($ millions)

	Upstream				
	2002	2001	2000	1999	1998
Year ended December 31					
Sales and operating revenues, net of royalties	$ 2,665	$ 2,165	$ 1,549	$ 595	$ 440
Costs and expenses					
Operating, cost of sales, selling and general	729	648	375	214	200
Depletion, depreciation and amortization	851	728	407	223	214
Interest — net	—	—	—	—	—
Foreign exchange	—	—	—	—	—
	1,580	1,376	782	437	414
Earnings (loss) before income taxes	1,085	789	767	158	26
Current income taxes	55	17	10	3	3
Future income taxes	342	290	305	50	20
Net earnings (loss)	$ 688	$ 482	$ 452	$ 105	$ 3
Capital employed — As at December 31[(2)]	$ 6,040	$ 5,715	$ 5,398	$ 2,077	$ 1,653
Total assets — As at December 31	$ 8,220	$ 7,407	$ 6,735	$ 2,839	$ 2,375

[Additional columns below]

[Continued from above table, first column(s) repeated]

	Midstream									
	Upgrading					Infrastructure and Marketing				
	2002	2001	2000	1999	1998	2002	2001	2000	1999	1998
Year ended December 31										
Sales and operating revenues, net of royalties	$ 909	$ 886	$1,006	$ 641	$ 412	$4,230	$4,380	$2,309	$1,284	$ 999
Costs and expenses										
Operating, cost of sales, selling and general	811	638	848	581	346	4,038	4,193	2,193	1,190	909
Depletion, depreciation and amortization	18	17	16	16	14	20	17	15	13	12
Interest — net	—	—	—	—	—	—	—	—	—	—
Foreign exchange	—	—	—	—	—	—	—	—	—	—
	829	655	864	597	360	4,058	4,210	2,208	1,203	921
Earnings (loss) before income taxes	80	231	142	44	52	172	170	101	81	78
Current income taxes	1	1	1	1	1	6	1	—	—	—
Future income taxes	25	72	53	21	22	59	71	45	36	35
Net earnings (loss)	$ 54	$ 158	$ 88	$ 22	$ 29	$ 107	$ 98	$ 56	$ 45	$ 43
Capital employed — As at December 31[(2)]	$ 319	$ 320	$ 352	$ 392	$ 418	$ 431	$ 395	$ 312	$ 353	$ 319

Total assets — As at

December 31	$ 658	$ 644	$ 613	$ 606	$ 605	$ 850	$ 862	$1,000	$ 652	$ 441

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

(2) Capital employed is defined as short- and long-term debt and shareholders' equity.

Certain prior years' amounts have been reclassified to conform with current presentation.

Segmented Financial Information
($ millions)

	Refined Products				
	2002	2001	2000	1999	1998
Year ended December 31					
Sales and operating revenues, net of royalties	$ 1,310	$ 1,349	$ 1,347	$ 904	$ 664
Costs and expenses					
Operating, cost of sales, selling and general	1,222	1,206	1,288	842	591
Depletion, depreciation and amortization	34	31	28	26	20
Interest — net	—	—	—	—	—
Foreign exchange	—	—	—	—	—
	1,256	1,237	1,316	868	611
Earnings (loss) before income taxes	54	112	31	36	53
Current income taxes	4	1	1	1	1
Future income taxes	18	48	14	16	23
Net earnings (loss)	$ 32	$ 63	$ 16	$ 19	$ 29
Capital employed — As at December 31[2]	$ 338	$ 329	$ 351	$ 366	$ 381
Total assets — As at December 31	$ 534	$ 428	$ 487	$ 476	$ 421

[Additional columns below]

[Continued from above table, first column(s) repeated]

	Corporate and Eliminations[1]				
	2002	2001	2000	1999	1998
Year ended December 31					
Sales and operating revenues, net of royalties	$ (2,730)	$ (2,184)	$ (1,145)	$ (637)	$ (492)
Costs and expenses					
Operating, cost of sales, selling and general	(2,696)	(2,165)	(1,060)	(514)	(437)
Depletion, depreciation and amortization	16	14	15	15	13
Interest — net	104	101	101	62	70
Foreign exchange	13	94	39	(55)	63
	(2,563)	(1,956)	(905)	(492)	(291)
Earnings (loss) before income taxes	(167)	(228)	(240)	(145)	(201)
Current income taxes	—	—	—	—	—
Future income taxes	(90)	(81)	(66)	(50)	(92)
Net earnings (loss)	$ (77)	$ (147)	$ (174)	$ (95)	$ (109)
Capital employed — As at December 31[2]	$ 384	$ (81)	$ (50)	$ 158	$ 134
Total assets — As at December 31	$ 313	$ 29	$ (6)	$ 203	$ 233

[Additional columns below]

[Continued from above table, first column(s) repeated]

	Total

	2002	2001	2000	1999	1998
Year ended December 31					
Sales and operating revenues, net of royalties	$ 6,384	$ 6,596	$ 5,066	$ 2,787	$ 2,023
Costs and expenses					
Operating, cost of sales, selling and general	4,104	4,520	3,644	2,313	1,609
Depletion, depreciation and amortization	939	807	481	293	273
Interest — net	104	101	101	62	70
Foreign exchange	13	94	39	(55)	63
	5,160	5,522	4,265	2,613	2,015
Earnings (loss) before income taxes	1,224	1,074	801	174	8
Current income taxes	66	20	12	5	5
Future income taxes	354	400	351	73	8
Net earnings (loss)	$ 804	$ 654	$ 438	$ 96	$ (5)
Capital employed — As at December 31[2]	$ 7,512	$ 6,678	$ 6,363	$ 3,346	$ 2,905
Total assets — As at December 31	$ 10,575	$ 9,370	$ 8,829	$ 4,776	$ 4,075

Segmented Financial Information

($ millions)	2002	2001	2000	1999	1998
Capital expenditures					
Upstream — Western Canada	$ 1,034	$ 1,022	$ 419	$ 238	$ 233
— East Coast Canada	458	191	194	309	191
— International	75	104	87	23	15
	1,567	1,317	700	570	439
Midstream — Upgrader	41	47	12	15	283
— Infrastructure and marketing	17	58	47	79	68
	58	105	59	94	351
Refined products	44	29	29	34	27
Corporate	23	22	15	8	12
	$ 1,692	$ 1,473	$ 803	$ 706	$ 829

Upstream Operating Information

	2002	2001	2000	1999	1998
Daily production, before royalties					
Light/medium crude oil & NGL *(mbbls/day)*	125.9	112.0	63.6	26.5	27.6
Lloydminster heavy crude oil *(mbbls/day)*	79.4	65.4	53.5	42.1	42.0
	205.3	177.4	117.1	68.6	69.6
Natural gas *(mmcf/day)*	569.2	572.6	358.0	250.5	232.6
Total production *(mboe/day)*	300.2	272.8	176.8	110.4	108.4
Average realized sales prices					
Light/medium crude oil & NGL *($/bbl)*	$ 33.28	$ 27.19	$ 33.42	$ 21.52	$ 16.07
Lloydminster heavy crude oil *($/bbl)*	$ 26.09	$ 15.85	$ 21.26	$ 16.00	$ 8.26
Natural gas *($/mcf)*	$ 3.83	$ 5.47	$ 5.16	$ 2.41	$ 2.17
Operating costs *($/boe)*	$ 6.24	$ 6.08	$ 5.27	$ 4.80	$ 4.53
Operating netbacks[1]					
Light/medium crude oil & NGL *($/boe)*	$ 21.20	$ 15.08	$ 20.61	$ 13.71	$ 9.78
Lloydminster heavy crude oil *($/boe)*	$ 16.02	$ 7.13	$ 12.11	$ 7.75	$ 1.61
Natural gas *($/mcfge)*	$ 2.44	$ 3.51	$ 3.59	$ 1.54	$ 1.46

(1) Operating netbacks are Husky's average realized prices less royalties, hedging (gains)/losses and operating costs on a per unit basis.

Certain prior years' amounts have been reclassified to conform with current presentation.

Upstream Operating Information (continued)

		2002		2001		2000		1999		1998	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Wells drilled[1]											
Exploration	Oil	21	20	78	76	16	13	9	9	16	11
	Gas	139	131	102	90	30	20	13	5	9	7
	Dry	15	14	36	34	9	9	9	9	8	6
		175	165	216	200	55	42	31	23	33	24
Development	Oil	497	453	594	542	411	363	203	190	75	55
	Gas	485	453	251	221	92	70	42	23	22	7
	Dry	58	55	68	63	30	28	23	22	6	4
		1,040	961	913	826	533	461	268	235	103	66
		1,215	1,126	1,129	1,026	588	503	299	258	136	90
Success ratio (percent)		94	94	91	91	93	93	89	88	90	89

(1) Western Canada.

Undeveloped Land Holdings

(thousands of acres - net)	2002	2001	2000	1999	1998
Western Canada					
Alberta	4,907	5,373	5,616	692	877
Saskatchewan	1,986	1,921	2,639	586	662
British Columbia	273	141	173	66	133
Manitoba	13	75	162	—	—
	7,179	7,510	8,590	1,344	1,672
Northwest Territories and Arctic	175	409	409	417	474
Eastern Canada	2,104	1,471	1,489	258	243
Total Canada	9,458	9,390	10,488	2,019	2,389
International	2,066	697	221	389	392
Total	11,524	10,087	10,709	2,408	2,781

Selected Eleven-Year Financial and Operating Summary

($ millions, except where indicated)	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993	1992
Sales and operating revenues, net of royalties	$6,384	$6,596	$5,066	$2,787	$2,023	$2,282	$2,104	$1,783	$1,373	$1,138	$ 977
Net earnings (loss)	$ 804	$ 654	$ 438	$ 96	$ (5)	$ 55	$ 49	$ 20	$ (40)	$ (249)	$ (395)
Net earnings per share											
Basic	$ 1.88	$ 1.49	$ 1.28	$ 0.34	$ (0.04)	$ 0.20	$ 0.18	$ 0.08	$ (0.15)	$ (0.92)	$ (1.46)
Diluted	$ 1.88	$ 1.48	$ 1.28	$ 0.34	$ (0.04)	$ 0.20	$ 0.18	$ 0.08	$ (0.15)	$ (0.92)	$ (1.46)
Cash flow from operations	$2,096	$1,946	$1,399	$ 517	$ 449	$ 453	$ 378	$ 303	$ 242	$ 171	$ 183
Cash flow from operations per share											
Basic	$ 4.94	$ 4.60	$ 4.26	$ 1.80	$ 1.61	$ 1.68	$ 1.40	$ 1.12	$ 0.90	$ 0.63	$ 0.68
Diluted	$ 4.92	$ 4.57	$ 4.26	$ 1.80	$ 1.61	$ 1.68	$ 1.40	$ 1.12	$ 0.90	$ 0.63	$ 0.68
Capital expenditures[1]	$1,692	$1,473	$ 803	$ 706	$ 829	$ 601	$ 218	$ 155	$ 257	$ 315	$ 312
Total debt	$2,385	$2,192	$2,378	$1,382	$1,131	$1,014	$ 853	$1,474	$1,667	$1,570	$1,570
Debt to capital employed *(percent)*	32	33	37	41	39	43	42	63	69	67	62
Debt to cash flow from operations *(times)*	1.1	1.1	1.7	2.7	2.5	2.2	2.3	4.9	6.9	9.2	8.6
Reinvestment ratio[3] *(percent)*	76	78	57	134	199	132	46	44	62	117	118
Return on average capital employed[2] *(percent)*	12.2	10.9	12.4	6.9	4.2	7.2	6.7	5.5	1.2	(8.5)	(12.8)
Return on equity[4] *(percent)*	16.7	15.4	19.4	11.4	6.7	12.1	11.7	14.1	(3.0)	(28.3)	(31.0)
Upstream											
Daily production, before royalties											
Light/medium crude oil & NGL *(mbbls/day)*	125.9	112.0	63.6	26.5	27.6	27.6	28.3	27.7	29.4	29.9	28.9
Lloydminster heavy crude oil *(mbbls/day)*	79.4	65.4	53.5	42.1	42.0	41.9	34.5	30.0	26.6	21.9	18.4
	205.3	177.4	117.1	68.6	69.6	69.5	62.8	57.7	56.0	51.8	47.3
Natural gas *(mmcf/day)*	569	573	358	251	233	246	268	286	248	246	252
Total production *(mboe/day)*	300.2	272.8	176.8	110.4	108.4	110.6	107.5	105.4	97.4	92.8	89.3
Total proved reserves, before royalties *(mmboe)*	918	927	872	430	431	421	432	416	401	408	472
Midstream											
Synthetic crude oil sales *(mbbls/day)*	59.3	59.5	60.6	61.9	54.8	27.5	26.8	26.6	18.8	11.3	0.6
Upgrading differential *($/bbl)*	$10.81	$17.91	$13.77	$ 6.49	$ 7.85	$ 8.54	$ 5.94	$ 4.34	$ 4.18	$ 5.50	$ 5.22
Pipeline throughput *(mbbls/day)*	457	537	528	394	412	417	359	296	238	217	169
Refined products											
Light oil sales *(million litres/day)*	7.7	7.6	7.4	7.6	6.0	4.5	4.2	3.9	3.2	2.9	2.5
Asphalt product sales *(mbbls/day)*	20.8	21.4	20.2	17.1	19.5	17.7	15.1	13.5	13.1	10.8	9.9
Refinery throughput											
Lloydminster refinery *(mbbls/day)*	22.0	23.7	23.4	17.9	21.9	21.5	18.4	15.6	16.4	13.2	10.9
Prince George refinery *(mbbls/day)*	10.1	10.2	9.2	10.2	9.9	10.3	10.0	9.9	9.7	9.7	8.7
Refinery utilization *(percent)*	92	97	93	80	91	91	81	73	75	65	56

(1) Excludes corporate acquisitions.

(2) Capital employed for purposes of this calculation has been weighted for 2000.

(3) Reinvestment ratio is based on net capital expenditures including corporate acquisitions (other than Renaissance Energy Ltd.).

(4) Equity for purposes of this calculation has been weighted for 2000 and includes amounts due to shareholders prior to August 25, 2000.

Certain prior years' amounts have been reclassified to conform with current presentation.

COMMON SHARE INFORMATION

Year ended December 31		2002	2001	2000
Share price	High	$ 17.98	$ 20.95	$ 15.95
	Low	$ 14.00	$ 13.10	$ 11.50
	Close at December 31	$ 16.47	$ 16.47	$ 14.90
Average daily trading volumes *(thousands)*		463	625	979
Number of common shares outstanding, December 31 *(thousands)*		417,874	416,878	415,803
Number of weighted average common shares outstanding *(thousands)*				
	Basic	417,425	416,100	415,803
	Diluted	419,334	418,640	416,753

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.

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
mcfge	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 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, retained earnings and amounts due to shareholders prior to August 25, 2000
Total Debt	Long-term debt including current portion and bank operating loans

Natural gas converted on the basis that six mcf of natural gas 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.

Exhibit 4

HUSKY ENERGY INC.

RECONCILIATION OF RESERVES INFORMATION

Set forth on page 91 of the Registrant's 2002 Annual Report

Exhibit 5

HUSKY ENERGY INC.

WELLS DRILLED INFORMATION

Set forth on page 48 of the Registrant's 2002 Annual Report

Exhibit 6

CONSENT OF INDEPENDENT CHARTERED ACCOUNTANTS

The Board of Directors
Husky Energy Inc.

We consent to the use of our report dated February 5, 2003 included in this annual report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

We also consent to the incorporation by reference of our report in the Registration Statement of Husky Energy Inc. on Form F-9 (No. 333-89714).

(Signed) KPMG LLP
Chartered Accountants

Calgary, Canada
March 26, 2003

Exhibit 7

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report auditing estimates of the natural gas, natural gas liquids and conventional oil reserves attributable to Husky Energy Inc. (the "Company") as of December 31, 2002 (the "Report").

We hereby consent to references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended. We also confirm that we have read the Annual Information Form and that we have no reason to believe that there are any misrepresentations in the information contained in it that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B. H. Emslie

B. H. Emslie, P. Eng.
Senior Vice President

Calgary, Alberta, Canada
March 26, 2003

Suite 2200, Bow Valley Square 3, 255 – 5th Avenue S.W., Calgary, Alberta T2P 3G6
Tel: (403) 262-5506 Fax: (403) 233-2744 Email: mcdaniel@mcdan.com Website: www.mcdan.com

Exhibit 8

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the period ended December 31, 2002 (the "Report") to which this certificate is an exhibit, I, John C.S. Lau, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 26, 2003

/s/ John C.S. Lau

John C.S. Lau
President & Chief Executive Officer

Exhibit 9

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the period ended December 31, 2002 (the "Report") to which this certificate is an exhibit, I, Neil D. McGee, Vice President and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 26, 2003

/s/ Neil D. McGee

Neil D. McGee
Vice President &
Chief Financial Officer