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 THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2003

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 No.)*

707 – 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:
None

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 422,175,742 Common Shares outstanding at December 31, 2003

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 such filing requirements for the past 90 days. Yes ☑ No ☐

This Annual Report on Form 40-F shall be incorporated by reference into the Registrant's Registration Statement on Form F-9 (File No. 333-89714).

Except where otherwise indicated, all dollar amounts stated in this Annual Report on Form 40-F are Canadian dollars.

Principal Documents

The following documents have been filed as part of this Annual Report on Form 40-F:

A. Annual Information Form

For our Annual Information Form for the year ended December 31, 2003, see Exhibit 1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For our consolidated audited financial statements for the year ended December 31, 2003, including the report of independent chartered accountants with respect thereto, see Exhibit 2 of this Annual Report on Form 40-F. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 20 of the Notes to the Consolidated Financial Statements.

C. Management's Discussion and Analysis

For Management's Discussion and Analysis for the year ended December 31, 2003, see Exhibit 3 of this Annual Report on Form 40-F.

Controls and Procedures

A. Disclosure Controls and Procedures

The Registrant'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 the end of the period covered by this Annual Report on Form 40-F (the ''evaluation date''), that the Registrant'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 Securities 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 Registrant's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

B. Changes in Internal Control Over Financial Reporting

There have been no significant changes to the Registrant's internal control over financial reporting or in other factors that could significantly affect internal control over financial reporting subsequent to the evaluation date and prior to the filing date of this Annual Report on Form 40-F.

Audit Committee Financial Expert

The Registrant's Board of Directors has determined that Martin J. Glynn is an audit committee financial expert serving on its audit committee (as defined in paragraph 8(b) of General Instruction B to Form 40-F). Mr. Glynn is currently the President and Chief Executive Officer of HSBC Bank USA. For a description of Mr. Glynn's relevant experience in financial matters, see Mr. Glynn's five year history in the section ''Directors and Officers'' in the Registrant's Annual Information Form for the year ended December 31, 2003, which is filed as Exhibit 1 to this Annual Report on Form 40-F.

Code of Ethics

The Registrant's code of ethics is disclosed in its Code of Business Conduct, which is applicable to all its employees, and is posted on its website at www.huskyenergy.ca. In the event that the Registrant:

(i) amends any provision of its Code of Business Conduct that applies to the Registrant's principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F, or

(ii) grants a waiver, including an implicit waiver, from a provision of its Code of Business Conduct to any of the Registrant's principal executive officer, principal financial officer, principal accounting officer

or controller or persons performing similar functions that relates to any element of the code of ethics definition as enumerated in paragraph (9)(b) of General Instruction B to Form 40-F.

the Registrant will disclose on its website any amendment to, or waiver of, a provision of its Code of Business Conduct within five business days following the date of any such amendment or waiver that relates to the items set forth above. Such disclosure will specifically describe the nature of the amendment or waiver, and will, in the case of a waiver, name the person to whom the waiver was granted.

Principal Accountant Fees and Services

The following table provides information about the fees billed to the Registrant for professional services rendered by KPMG LLP, the Registrant's principal accountant, during fiscal 2003 and 2002:

	Aggregate fees billed by the Principal Accountant	
	2003	2002
	($ thousands)	
Audit fees	630	464
Audit-related fees	24	67
Tax fees	196	90
All other fees	33	79
	883	700

Audit Fees. Audit fees consist of fees for the audit of the Registrant's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related services included audit of certain subsidiaries and financial aspects of the Registrant.

Tax Fees. Tax fees included tax planning and various taxation matters.

All Other Fees. Other services provided by the Registrant's principal accountant, other than audit, audit-related and tax services, included advisory services associated with the Sarbanes-Oxley Act of 2002.

The Registrant's Audit Committee has the sole authority to review in advance, and grant any appropriate pre-approvals, of all non-audit services to be provided by the independent auditors and, in connection therewith, to approve all fees and other terms of engagement.

Off-Balance Sheet Arrangements

See the Registrant's Management's Discussion and Analysis for the year ended December 31, 2003, which is filed as Exhibit 3 to this Annual Report on Form 40-F.

Disclosure of Contractual Obligations

In the normal course of business the Registrant is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

	Contractual Obligations				
	Payment due by period				
	Total	2004	2005-2006	2007-2008	Thereafter
	($ millions)				
Long-term debt	1,698	259	286	146	1,007
Capital securities	291	—	—	—	291
Operating leases	514	50	144	145	175
Firm transportation agreements	1,788	236	443	369	740
Unconditional purchase obligations	915	332	444	124	15
Exploration lease agreements	497	47	120	97	233
Engineering and construction commitments	597	391	206	—	—
	6,300	1,315	1,643	881	2,461

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

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.

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.

Any change to the name and address of the agent for service for service of process of the Registrant shall be communicated promptly to the Securities and Exchange Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

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.

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

March 18, 2004

EXHIBITS

Exhibit	Description
1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2003.
2	Consolidated Audited Financial Statements of the Registrant for the year ended December 31, 2003, including a reconciliation to United States generally accepted accounting principles and Auditors' Report to the Shareholders.
3	Management's Discussion and Analysis of the Registrant for the year ended December 31, 2003.
4	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
5	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
6	Certifications of Chief Executive Officer pursuant to Rule 13(a)-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
7	Certifications of Chief Financial Officer pursuant to Rule 13(a)-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
8	Consent of KPMG LLP, independent accountants.
9	Consent of McDaniel and Associates Consultants Ltd., independent engineers.

Exhibit 1

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2003

HUSKY ENERGY INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2003

March 18, 2004

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EXCHANGE RATE INFORMATION

Except where otherwise indicated, all dollar amounts stated in this Annual Information Form are Canadian dollars. The following table discloses various indicators of the Canadian/United States rate of exchange or the cost of a U.S. dollar in Canadian currency for the three years indicated.

	Year Ended December 31,		
	2003	2002	2001
Year end	1.292	1.580	1.593
Low	1.292	1.519	1.499
High	1.575	1.605	1.593
Average	1.386	1.570	1.551

Notes:

(1) The exchange rates were as quoted by the Federal Reserve Bank of New York for the noon buying rate.

(2) The high, low and average rates were either quoted or calculated as of the last day of the relevant month.

ABBREVIATIONS

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

Units of Measure

Bbl	- barrel
Bbls	- barrels
mbbls	- thousand barrels
mmbbls	- million barrels
Bbls/day	- barrels per calendar day
mbbls/day	- thousand barrels per calendar day
Boe	- barrels of oil equivalent
boe/day	- barrels of oil equivalent per calendar day
Mcf	- thousand cubic feet
mmcf	- million cubic feet
Bcf	- billion cubic feet
mmcf/day	- million cubic feet per calendar day
mcfge	- thousand cubic feet of gas equivalent
lt	- long ton
mlt	- thousand long tons
lt/day	- long tons per calendar day
mlt/day	- thousand long tons per calendar day
mmbtu	- million British thermal units
MW	- megawatts

Acronyms

API	- American Petroleum Institute
COGE Handbook	- Canadian Oil and Gas Evaluation Handbook
FASB	- Financial Accounting Standards Board
FPSO	- floating production, storage and offloading vessel
NGL	- natural gas liquids
NYMEX	- New York Mercantile Exchange
OPEC	- Organization of Petroleum Exporting Countries
PSC	- production sharing contract
SAGD	- steam assisted gravity drainage
SEC	- Securities and Exchange Commission of the United States
SEDAR	- System for Electronic Document Analysis and Retrieval
WTI	- West Texas Intermediate crude oil

Unless otherwise indicated, 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. Unless otherwise indicated, oil and gas commodity prices are quoted after the effect of hedging gains and losses. Natural gas volumes are stated at the official temperature and pressure basis of the area in which the reserves are located. The calculation of barrels of oil equivalent (boe) and thousands of cubic feet equivalent (mcfge) are based on a conversion rate of six thousand cubic feet to one barrel of oil.

Boe or mcfge may be misleading, particularly if used in isolation. The reader is cautioned that a boe conversion rate of six to one is based on an energy equivalence conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

DISCLOSURE EXEMPTION UNDER NATIONAL INSTRUMENT 51-101

Husky believes that comparability of its disclosures with those required in its major capital market, the United States, is important to many of the investors and prospective investors in its securities. Accordingly, Husky applied for and was granted an exemption by the Canadian securities regulators under the provisions of National Instrument 51-101 ''Standards of Disclosures for Oil and Gas Activities'' (''NI 51-101''). The exemption, under Section 8.4 of the Companion Policy to NI 51-101, permits Husky to substitute disclosures required by and consistent with those of the Securities and Exchange Commission (''SEC'') and the Financial Accounting Standards Board (''FASB'') in the United States in place of much of the disclosure expected by NI 51-101. In accordance with the exemption, proved oil and gas reserves data and certain other disclosures with respect to Husky's oil and gas activities in this Annual Information Form are presented in accordance with the following requirements:

- The FASB Statement No. 69 ''Disclosure about Oil and Gas Producing Activities — an amendment of FASB Statements No.'s 19, 25, 33 and 39'' (''FAS 69'');
- FASB Current Text Section Oi5, ''Oil and Gas Producing Activities'' paragraph .103, .106, .107, .108, .112, .160 through .167 and .174 through .184 and .401 through .408;
- SEC Industry Guide 2;
- SEC Item 102 of regulation S-K (17 CFR 229.102);
- SEC Item 302(b) of Regulation S-K (17 CFR 229.302(b)) ; and
- The definitions and disclosures required by SEC Regulation S-X (CFR 210.4-10).

Proved oil and gas reserves information and other disclosures about oil and gas activities in this Annual Information Form following SEC requirements may differ from corresponding information otherwise required by NI 51-101. Proved reserves disclosed in this Annual Information Form are in accordance with the SEC definitions.

NI 51-101 specifies that proved reserves be in accordance with the COGE Handbook definitions. There were no material differences between the oil and gas reserves determined and evaluated using the SEC definitions and the COGE Handbook definitions. In addition, NI 51-101 requires the inclusion of probable reserves and their associated future net revenue. The SEC does not normally permit the disclosure of probable reserves in documents filed with them.

The SEC requires the evaluation of oil and gas reserves to be based on prices, costs, fiscal regimes and other economic and operating conditions in effect at the time the evaluation is made. NI 51-101 also requires the evaluation of oil and gas reserves on this basis but also requires an evaluation of oil and gas reserves to be based on a forecast of economic conditions.

NI 51-101 prescribes a relatively comprehensive set of disclosures in respect of oil and gas reserves and other disclosures about oil and gas activities. In comparison, the SEC prescribes a minimum set of disclosures and advises not to approach the SEC rules and regulations as merely a blank form but encourages registrants to provide such additional information that is necessary to further an investor's understanding of the registrant's business.

Husky believes that it's reserves evaluators are qualified and it has a well established reserves evaluation process that is at least as rigorous as would be the case were it to rely upon independent reserves evaluators. Husky has adopted written evaluation practices and procedures using the COGE Handbook modified to the extent necessary to reflect the definitions and standards under U.S. disclosure requirements.

CORPORATE STRUCTURE

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.

Intercorporate Relationships

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	Alberta
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

Name	Jurisdiction
Subsidiaries of Husky (U.S.A.) Inc.	
Husky Gas Marketing Inc.	Delaware
Subsidiaries of HOI Resources Co.	
Husky Energy International Corporation	Alberta
Subsidiaries of Husky Energy International Corporation	
Husky Oil China Ltd.	Alberta
Husky Oil (Madura) Ltd.	Alberta
Husky Oil Overseas Ltd.	Alberta

GENERAL DEVELOPMENT OF HUSKY

Three Year History

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.

In 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.

In January 2002, the Terra Nova development project commenced production. This project was the first Grand Banks field to be developed with a floating production, storage and offloading system. In addition, the first well in the Terra Nova Far East block was successfully drilled in 2001.

In June 2002, Husky issued U.S. $400 million of 6.25% senior notes due June 15, 2012. The notes were sold at a discount 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. These 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 with the China National Offshore Oil Corporation (''CNOOC'') for two exploration blocks in the South China Sea. The 23/15 block comprises 1,327 square kilometres and the 23/20 block comprises 1,543 square kilometres. The contracts require one well to be drilled on each block 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 in 2002.

In December 2002, Husky signed a contract with CNOOC 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 57,600 acres of lands with in-situ potential. Husky's property has been named ''Sunrise.''

Effective October 1, 2003, Husky purchased all of the outstanding common shares of Marathon Canada Limited (''Marathon'') and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. The total purchase price was U.S.$588 million. In a separate concurrent transaction Husky sold certain of the Marathon properties to another unrelated company for total proceeds of U.S.$320 million. The properties retained by Husky are located throughout western Alberta and north-eastern British Columbia. The acquisition added approximately 39.8 mmboe of gross proved reserves, of which 75% was natural gas, and 729,000 acres of undeveloped lands in Alberta, British Columbia and the Northwest Territories.

In November 2003, Husky announced that it had signed a contract with CNOOC for the 04/35 exploration block in the East China Sea. The block comprises 4,835 square kilometres and requires one well to be drilled within the first three years of the contract.

In November 2003, Husky established a securitization program to sell, on a revolving basis, up to $250 million of its accounts receivable to a third party. The agreement includes a program fee based on Canadian commercial paper rates.

Business Environment Trends

There are a number of trends that appear to be developing, which may have both long and short-term effects on the oil and gas industry. The Western Canada Sedimentary Basin continues to mature and a large number of major producing regions have been highly developed, thereby reducing the exploration opportunities in this area.

There is a continued trend relating to the volatility of commodity prices. It appears that natural gas prices have entered an era of extreme volatility. With the supply and demand balance for natural gas being extremely tight, the market is experiencing a great deal of elasticity in pricing due to a number of factors, including weather, drilling activity, declines, storage levels, fuel switching and demand.

Oil prices are clearly dependent on the world economy and the reaction of OPEC to demand. OPEC's stated position is to maintain its average basket price between U.S.$22.00-$28.00 per bbl and, if successful, will remove some volatility in the WTI price. This does not, however, affect a major oil trend developing in Canada. The trend in Canada involves increasing production of heavy oil that is priced at a differential to WTI. This differential is presently wide but as the North American refineries are forced to accept more of the heavy crude there should be a narrowing of the differential. This may result in a trend that will see heavy crude priced at a differential that will only include the price of diluent to move the produce from the delivery point to the refineries.

DESCRIPTION OF HUSKY'S BUSINESS

General

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 Operations

Husky's portfolio of assets includes properties that produce light (30° API and lighter), medium (between 20° and 30° API) and heavy (below 20° and above 10° API) 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 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 concentrated landholdings, production, gathering and processing facilities, as well as heavy crude oil pipeline, upgrading and refining facilities.

At December 31, 2003, Husky was the operator of properties which accounted for approximately 87% of its total gross production in Western Canada. Husky's undeveloped landholdings in the Western Canada Sedimentary Basin totalled 7.3 million net acres at December 31, 2003.

In the foothills deep basin areas in Alberta, Husky operates the Ram River gas plant and has interests in properties that supply this 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 Galloway, Ansell and 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 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 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 throughout south-west Saskatchewan at Shackleton/Lacadena, Cantaur, Fosterton and Carnduff.

Husky has extensive experience in development, production, transportation and upgrading of heavy crude oil. Husky also has experience in enhanced recovery of crude oil and horizontal drilling, as well as in natural gas exploration in the deep basin, foothills and along the eastern slopes of the Canadian Rocky Mountains, also known as the overthrust belt.

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 by the co-venturers in March 2002 and is currently under development. First oil from the White Rose oil field is currently expected by the end of 2005 or early 2006. Husky also holds interests in several exploration and significant discovery licenses in the Jeanne d'Arc Basin and the South Whale 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 four exploration blocks in the South China Sea with an aggregate areal extent of approximately 15,000 square kilometres and one exploration block in the East China Sea of approximately 4,800 square kilometres.

Husky also holds an interest in a natural gas and liquids PSC located in the Madura strait offshore Java, Indonesia.

Midstream Operations

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

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 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.

Social and Environmental Policy

Husky's environmental policy requires regular environmental audits to be conducted at its sites and facilities. Husky has established procedures designed to anticipate and minimize adverse effects of its operations on the environment and for continued compliance with environmental legislation and minimize future and current costs. Husky's policies apply equally to employees, subsidiaries and contractors.

Risk Factors

The following factors should be considered in evaluating Husky:

Adequacy of crude oil and natural gas prices

Husky's results of operations and financial condition are dependent on the prices received for its crude oil and natural gas production.

Prices for crude oil are based on world supply and demand. Supply and demand can be affected by a number of factors including, but not limited to, actions taken by the OPEC and their adherence to agreed production quotas, non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, prevailing weather patterns and the availability of alternate sources of energy.

Husky's natural gas production is located entirely in Western Canada and is, therefore, subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of natural gas available to specific market areas either from the well head or from storage facilities, prevailing weather patterns, the price of crude oil, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

Demand for Husky's other products and services and the cost of required inputs

Husky's results of operations and financial condition are dependent on the price of refinery feedstock, the price of energy, the demand for refined petroleum products and electrical power and the ability of Husky to recover the increased cost of these inputs from the customer. Husky is also dependent on the demand for Husky's pipeline and processing capacity.

Husky's ability to replace reserves

Husky's future cash flow and cost of capital are dependent on its ability to replace its proved oil and gas reserves in a cost effective manner. Without economic reserve additions through exploration and development or acquisition Husky's production and, therefore, cash flow will decline. Without adequate proved reserves Husky's ability to fund development and other capital expenditures with external sources of funds is diminished.

Competition

The energy industry is highly competitive. Husky competes with others to acquire additional prospective lands, to retain drilling capacity and field operating and construction services, to attract and retain experienced skilled management and oil and gas professionals, to obtain sufficient pipeline and other transportation capacity and to gain access to and retain adequate markets for Husky's products and services. Husky's competitors comprise all types of energy companies, some of which have greater resources.

Environmental risks

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of federal, provincial and municipal laws and regulations, as well as international conventions (collectively, ''environmental legislation'').

Environmental legislation imposes, among other things, restrictions, liabilities, and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, facilities and other properties associated with Husky's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean-up costs and damages. Husky cannot be certain that the costs of complying with environmental legislation in the future will not have a material adverse effect on Husky's financial condition and results of operations.

Husky anticipates that changes in environmental legislation may require, among other things, reductions in emissions from its operations and result in increased capital expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on Husky's financial condition and results of operations.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol, which requires the reduction of greenhouse gas emissions. On December 16, 2002, Canada ratified the Kyoto Protocol. This initiative may require Husky to significantly reduce emissions at its operations of green house gases such as carbon dioxide, which may increase capital expenditures, details regarding the implementation of the Kyoto Protocol remain unclear.

Uncertainty of oil and gas proved reserves estimates

There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves, including many factors beyond Husky's control. The reserves information included in and incorporated by reference in this Annual Information Form are Husky's estimates. In general, estimates of economically recoverable oil and natural gas reserves and the estimated future net cash flow therefrom are based on a number of variables in effect as of date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the actual effects of regulation by governmental agencies and the actual future commodity prices and operating costs, all of which may vary considerably from those in effect at the date the reserves were determined. The estimated quantities of reserves expected to be recovered are uncertain and the classification of reserves as proved is only an attempt to define the degree of certainty involved. For these reasons, estimates of economically recoverable oil and natural gas attributable to a particular group of properties, the classification of such reserves as proved and the resultant future net cash flow therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Husky's actual production, revenues, taxes and development, abandonment, and operating expenditures with respect to the estimated oil and natural gas reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future (proved developed reserves) are often based on volumetric calculations and upon analogy to similar types of reservoirs, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves, which may be material.

Upstream Operations — Disclosures for Oil and Gas Activities

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:

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
	Crude oil — mbbls/day Natural gas — mmcf/day					
Crude Oil						
Light crude oil and NGL	71.6	32.2	16.8	49.0	22.4	0.2
Medium crude oil	39.2	39.2	—	39.2	—	
Heavy crude oil	99.9	99.9	—	99.9	—	
Total gross	210.7	171.3	16.8	188.1	22.4	0.2
Total net	186.8	149.5	16.7	166.2	20.4	0.2
Natural Gas						
Gross	610.6	610.6	—	610.6	—	—
Net	473.7	473.7	—	473.7	—	—

	2002					
	Total	Western Canada	East Coast	Canada	China	Libya
	Crude oil — mbbls/day Natural gas — mmcf/day					
Crude Oil						
Light crude oil and NGL	65.4	39.8	13.2	53.0	12.2	0.2
Medium crude oil	44.8	44.8	—	44.8	—	—
Heavy crude oil	95.1	95.1	—	95.1	—	—
Total gross	205.3	179.7	13.2	192.9	12.2	0.2
Total net	179.3	154.8	12.8	167.6	11.5	0.2
Natural Gas						
Gross	569.2	569.2	—	569.2	—	—
Net	426.6	426.6	—	426.6	—	—

	2001					
	Total	Western Canada	East Coast	Canada	China	Libya
	Crude oil — mbbls/day Natural gas — mmcf/day					
Crude Oil						
Light crude oil and NGL	46.4	46.1	—	46.1	—	0.3
Medium crude oil	47.2	47.2	—	47.2	—	—
Heavy crude oil	83.8	83.8	—	83.8	—	—
Total gross	177.4	177.1	—	177.1	—	0.3
Total net	154.4	154.1	—	154.1	—	0.3
Natural Gas						
Gross	572.6	572.6	—	572.6	—	—
Net	417.8	417.8	—	417.8	—	—

Notes:

(1) Light crude oil includes crude oil that is lighter than 30° API, medium crude oil is between 20° and 30° API gravity and heavy crude oil includes crude oil that is lower than 20° API and lighter than 10° 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.

Revenue

The following table shows the revenue by upstream product group for the years indicated:

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	879	300	238	538	338	3
Medium crude oil	556	556	—	556	—	—
Heavy crude oil	943	943	—	943	—	—
Total gross	2,378	1,799	238	2,037	338	3
Total net	2,082	1,539	233	1,772	307	3
Natural Gas						
Gross	1,346	1,346	—	1,346	—	—
Net	1,058	1,058	—	1,058	—	—
Processing	46	46	—	46	—	—

	2002					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	866	494	171	665	198	3
Medium crude oil	496	496	—	496	—	—
Heavy crude oil	924	924	—	924	—	—
Total gross	2,286	1,914	171	2,085	198	3
Total net	1,974	1,616	169	1,785	186	3
Natural Gas						
Gross	801	801	—	801	—	—
Net	653	653	—	653	—	—
Processing	38	38	—	38	—	—

	2001					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	561	557	—	557	—	4
Medium crude oil	408	408	—	408	—	—
Heavy crude oil	521	521	—	521	—	—
Total gross	1,490	1,486	—	1,486	—	4
Total net	1,249	1,245	—	1,245	—	4
Natural Gas						
Gross	1,142	1,142	—	1,142	—	—
Net	882	882	—	882	—	—
Processing	35	35	—	35	—	—

Note:

(1) Light crude oil includes crude oil that is lighter than 30° API, medium crude oil is between 20° and 30° API gravity and heavy crude oil includes crude oil that is lower than 20° API and lighter than 10° API gravity in the Lloydminster area.

Sales Prices

The following table shows the Company's average sales prices, before and after the effect of production hedging, for light crude oil and NGL, medium crude oil, heavy crude oil and natural gas for the periods indicated.

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
	$/bbl $/mcf					
Crude Oil						
Light crude oil and NGL	39.53	38.28	38.91	38.49	41.45	40.44
Medium crude oil	31.42	31.42	—	31.42	—	—
Heavy crude oil	25.87	25.87	—	25.87	—	—
Total crude oil and NGL (before hedging)	31.54	29.48	38.91	30.32	41.45	40.44
Total crude oil and NGL (after hedging)	30.93	28.96	36.96	29.67	41.45	40.44
Natural Gas						
Before hedging	5.86	5.86	—	5.86	—	—
After hedging	5.94	5.94	—	5.94	—	—

	2002					
	Total	Western Canada	East Coast	Canada	China	Libya
	$/bbl $/mcf					
Crude Oil						
Light crude oil and NGL	36.17	33.86	35.47	34.26	44.36	40.37
Medium crude oil	30.16	30.16	—	30.16	—	—
Heavy crude oil	26.60	26.60	—	26.60	—	—
Total crude oil and NGL (before hedging)	30.47	29.14	35.47	29.57	44.36	40.37
Total crude oil and NGL (after hedging)	30.50	29.17	35.47	29.61	44.36	40.37
Natural Gas						
Before hedging	3.83	3.83	—	3.83	—	—
After hedging	3.83	3.83	—	3.83	—	—

	2001					
	Total	Western Canada	East Coast	Canada	China	Libya
			$/bbl $/mcf			
Crude Oil						
Light crude oil and NGL	33.15	33.13	—	33.13	—	37.72
Medium crude oil	23.69	23.69	—	23.69	—	—
Heavy crude oil	17.02	17.02	—	17.02	—	—
Total crude oil and NGL (before hedging)	23.01	22.99	—	22.99	—	37.72
Total crude oil and NGL (after hedging)	23.01	22.99	—	22.99	—	37.72
Natural Gas						
Before hedging	5.47	5.47	—	5.47	—	—
After hedging	5.47	5.47	—	5.47	—	—

Note:

(1) Light crude oil includes crude oil that is lighter than 30° API, medium crude oil is between 20° and 30° API gravity and heavy crude oil includes crude oil that is lower than 20° API and lighter than 10° API gravity in the Lloydminster area.

Capital Expenditures

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

	2003						
	Total	Western Canada	East Coast	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisition (1)	75	75	—	75	—	—	—
Exploration	324	274	24	298	26	—	—
Development	1,382	849	533	1,382	—	—	—

	2002						
	Total	Western Canada	East Coast	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisitions	108	108	—	108	—	—	—
Exploration	266	216	41	257	9	—	—
Development	1,193	710	417	1,127	66	—	—

	2001						
	Total	Western Canada	East Coast	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisitions (2)	177	177	—	177	—	—	—
Exploration	267	181	81	262	5	—	—
Development	873	664	110	774	99	—	—

Notes:

(1) Does not include the acquisition of Marathon.

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

Oil and Gas Netbacks[1]

The following table shows the Company's average netback for operations classified as light, medium and heavy crude oil operations, and natural gas operations for the periods indicated. The classification is based on the oil/gas ratio such that predominantly oil leases are classified with oil operations and predominantly natural gas leases are classified with natural gas operations.

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
			$/bbl $/mcf			
Crude Oil						
Light crude oil						
Sales revenue	40.17	39.91	38.91	39.55	41.45	40.44
Royalties	4.55	7.28	0.81	4.93	3.80	—
Operating costs	5.41	9.27	3.16	7.05	1.94	15.43
Netback before hedging	30.21	23.36	34.94	27.57	35.71	25.01
Netback after hedging	29.49	22.80	32.99	26.50	35.71	25.01
Medium crude oil						
Sales revenue	31.57	31.57	—	31.57	—	—
Royalties	5.28	5.28	—	5.28	—	—
Operating costs	9.53	9.53	—	9.53	—	—
Net back before hedging	16.76	16.76	—	16.76	—	—
Netback after hedging	14.97	14.97	—	14.97	—	—
Heavy crude oil						
Sales revenue	25.98	25.98	—	25.98	—	—
Royalties	2.76	2.76	—	2.76	—	—
Operating costs	9.09	9.09	—	9.09	—	—
Netback before hedging	14.13	14.13	—	14.13	—	—
Netback after hedging	14.13	14.13	—	14.13	—	—
Total crude oil						
Sales revenue	31.70	29.52	38.91	30.53	41.45	40.44
Royalties	3.83	4.14	0.81	3.84	3.80	—
Operating costs	7.97	9.23	3.16	8.68	1.94	15.43
Netback before hedging	19.90	16.15	34.94	18.01	35.71	25.01
Netback after hedging	19.32	15.63	32.99	17.36	35.71	25.01
Natural Gas						
Sales revenue	5.79	5.79	—	5.79	—	—
Royalties	1.29	1.29	—	1.29	—	—
Operating costs	0.79	0.79	—	0.79	—	—
Netback before hedging	3.71	3.71	—	3.71	—	—
Netback after hedging	3.79	3.79	—	3.79	—	—

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.

	2002					
	Total	Western Canada	East Coast	Canada	China	Libya
			$/bbl $/mcf			
Crude Oil						
Light crude oil						
Sales revenue	36.22	33.66	35.47	34.15	44.36	40.37
Royalties	3.25	4.55	0.36	3.41	2.65	—
Operating costs	7.33	10.46	3.62	8.60	2.15	13.13
Netback before hedging	25.64	18.65	31.49	22.14	39.56	27.24
Netback after hedging	25.74	18.82	31.49	22.26	39.56	27.24
Medium crude oil						
Sales revenue	29.92	29.92	—	29.92	—	—
Royalties	5.59	5.59	—	5.59	—	—
Operating costs	7.19	7.19	—	7.19	—	—
Netback before hedging	17.14	17.14	—	17.14	—	—
Netback after hedging	17.33	17.33	—	17.33	—	—
Heavy crude oil						
Sales revenue	26.48	26.48	—	26.48	—	—
Royalties	3.45	3.45	—	3.45	—	—
Operating costs	7.18	7.18	—	7.18	—	—
Net back before hedging	15.85	15.85	—	15.85	—	—
Netback after hedging	15.85	15.85	—	15.85	—	—
Total crude oil						
Sales revenue	30.19	28.81	35.47	29.26	44.36	40.37
Royalties	3.87	4.22	0.36	3.96	2.65	—
Operating costs	7.23	7.84	3.62	7.54	2.15	13.13
Netback before hedging	19.09	16.75	31.49	17.76	39.56	27.24
Netback after hedging	19.16	16.83	31.49	17.84	39.56	27.24
Natural Gas						
Sales revenue	3.97	3.97	—	3.97	—	—
Royalties	0.81	0.81	—	0.81	—	—
Operating costs	0.70	0.70	—	0.70	—	—
Netback before hedging	2.46	2.46	—	2.46	—	—
Netback after hedging	2.46	2.46	—	2.46	—	—

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.

	2001					
	Total	Western Canada	East Coast	Canada	China	Libya
			$/bbl $/mcf			
Crude Oil						
Light crude oil						
Sales revenue	34.28	34.25	—	34.25	—	37.72
Royalties	5.72	5.76	—	5.76	—	—
Operating costs	8.19	8.15	—	8.15	—	14.56
Netback before hedging	20.37	20.34	—	20.34	—	23.16
Netback after hedging	20.37	20.34	—	20.34	—	23.16
Medium crude oil						
Sales revenue	23.86	23.86	—	23.86	—	—
Royalties	4.39	4.39	—	4.39	—	—
Operating costs	7.18	7.18	—	7.18	—	—
Netback before hedging	12.29	12.29	—	12.29	—	—
Netback after hedging	12.29	12.29	—	12.29	—	—
Heavy crude oil						
Sales revenue	17.20	17.20	—	17.20	—	—
Royalties	1.93	1.93	—	1.93	—	—
Operating costs	7.40	7.40	—	7.40	—	—
Netback before hedging	7.87	7.87	—	7.87	—	—
Netback after hedging	7.87	7.87	—	7.87	—	—
Total crude oil						
Sales revenue	23.13	23.09	—	23.09	—	37.72
Royalties	3.52	3.52	—	3.52	—	—
Operating costs	7.53	7.51	—	7.51	—	14.56
Netback before hedging	12.08	12.06	—	12.06	—	23.16
Netback after hedging	12.08	12.06	—	12.06	—	23.16
Natural Gas						
Sales revenue	5.39	5.39	—	5.39	—	—
Royalties	1.30	1.30	—	1.30	—	—
Operating costs	0.58	0.58	—	0.58	—	—
Netback before hedging	3.51	3.51	—	3.51	—	—
Netback after hedging	3.51	3.51	—	3.51	—	—

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, 2003 and 2002 in which Husky held a working interest:

	Oil Wells		Natural Gas Wells		Total	
	Gross (1)(2)	**Net** (1)	**Gross** (1)(2)	**Net** (1)	**Gross** (1)(2)	**Net** (1)
Canada						
Alberta	5,098	3,410	5,660	2,877	10,758	6,287
Saskatchewan	4,835	3,596	675	422	5,510	4,018
British Columbia	211	63	111	48	322	111
Manitoba	2	1	—	—	2	1
Newfoundland	8	1	—	—	8	1
	10,154	7,071	6,446	3,347	16,600	10,418
International						
China	21	8	—	—	21	8
Libya	2	1	—	—	2	1
	23	9	—	—	23	9
As at December 31, 2003	10,177	7,080	6,446	3,347	16,623	10,427
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
As at December 31, 2002	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) 2003 includes 271 gross, 241 net oil wells and 424 gross, 207 net 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.

2002 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.

Landholdings

The following table presents Husky's developed acreage as at December 31, 2003 and 2002:

	Developed Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2003		
Western Canada		
Alberta	3,208	2,684
Saskatchewan	550	485
British Columbia	161	92
Manitoba	1	1
	3,920	3,262
Eastern Canada	35	4
Total Canada	3,955	3,266
China	17	7
Libya	7	2
	3,979	3,275
As at December 31, 2002		
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
Total Canada	3,523	2,976
China	17	7
Libya	7	2
	3,547	2,985

The following table presents Husky's undeveloped acreage as at December 31, 2003 and 2002:

	Undeveloped Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2003		
Western Canada		
Alberta	5,508	4,852
Saskatchewan	2,057	1,911
British Columbia	713	491
Manitoba	9	8
	8,287	7,262
Northwest Territories and Arctic	527	184
Eastern Canada	2,414	2,104
Total Canada	11,228	9,550
International	4,464	2,066
	15,692	11,616
As at December 31, 2002		
Western Canada		
Alberta	5,416	4,907
Saskatchewan	2,098	1,986
British Columbia	314	273
Manitoba	13	13
	7,841	7,179
Northwest Territories and Arctic	463	175
Eastern Canada	2,414	2,104
Total Canada	10,718	9,458
International	4,464	2,066
	15,182	11,524

Drilling Activity

Husky's gross and net exploratory and development drilling activities in Western Canada for the years ended December 31, 2003, 2002 and 2001 are set forth below:

	Year ended December 31					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Western Canada Drilling						
Exploration						
Oil	12	11	21	20	78	76
Gas	147	124	139	131	102	90
Dry	22	21	15	14	36	34
	181	156	175	165	216	200
Development						
Oil	520	490	497	453	594	542
Gas	540	518	485	453	251	221
Dry	60	57	58	55	68	63
	1,120	1,065	1,040	961	913	826
	1,301	1,221	1,215	1,126	1,129	1,026

The following table presents the number of gross and net exploratory and development wells that were drilling at December 31, 2003:

Present Activities

Wells Drilling	Exploratory Gross	Exploratory Net	Development Gross	Development Net
Western Canada	8	6.750	17	15.150
East Coast	—	—	1	0.175
China	—	—	—	—
	8	6.750	18	15.325

Reserves Data and Other Information

Husky's oil and gas reserves as of December 31, 2003 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.

Reserves Reported to Other Agencies

There have been no reserves reported to any U.S. federal authority or agency since the beginning of the last fiscal year.

Audit of Oil and Gas Reserves

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the COGE Handbook.

Oil and Gas Reserves Data

The following table presents in summary Husky's proved developed reserves, proved undeveloped reserves and associated future net cash flows as at December 31, 2003. Future revenues, based on constant prices and costs, are presented net of royalties. 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		Natural Gas		Future Net Cash Flows Before Tax (3)(4)	
	Gross (1)	Net (1)	Gross (1)	Net (1)	0%	10%
	(mmbbls)		(bcf)		($ millions)	
Proved developed (2)	442.1	394.5	1,712.4	1,422.9	13,930	8,232
Proved undeveloped (2)	102.2	91.0	346.5	293.7	2,209	1,144
Proved total (2)	544.3	485.5	2,058.9	1,716.6	16,139	9,376

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 SEC Regulation S-X.

(3) The discounted future net cash flows at December 31, 2003 were based on the year-end spot NYMEX natural gas price of U.S. $5.96/mmbtu and on a spot WTI crude oil price of U.S. $32.51/bbl.

(4) Future Development Costs

	As at December 31, 2003						
	Total	2004	2005	2006	2007	2008	Thereafter
	($ millions undiscounted)						
Western Canada	1,229	366	241	108	68	49	397
Eastern Canada	39	28	4	3	1	—	3
China	—	—	—	—	—	—	—
Indonesia	—	—	—	—	—	—	—
	1,265	338	245	111	69	49	400

	As at December 31, 2002						
	Total	2003	2004	2005	2006	2007	Thereafter
Western Canada	1,100	325	160	116	63	56	380
Eastern Canada	41	32	2	2	1	2	2
China	—	—	—	—	—	—	—
Indonesia	154	—	41	73	40	—	—
	1,295	357	203	191	104	58	382

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

Reserves and Production by Principal Area

Husky's estimate of its proved reserves by area as of December 31, 2003 and daily average production of crude oil, NGL and natural gas by area are as follows:

Crude Oil and NGL	Proved Reserves (mmbbls)	Production (mbbls/day)
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	31.8	6.4
Foothills Deep Gas area	24.0	7.1
Ram River and Kaybob areas	6.5	2.0
Northwest Alberta Plains		
Rainbow Lake area	85.0	7.8
Peace River Arch area	11.2	3.4
East Central Alberta		
Provost area	33.8	20.8
North area	2.0	0.7
South area	6.4	2.7
Southern Alberta and Saskatchewan		
South Alberta area	21.8	11.7
South Saskatchewan area	76.1	18.4
Lloydminster Area		
Primary production	132.3	75.0
Thermal production	62.6	14.8
Other	0.7	0.6
	494.2	171.4
East Coast Canada		
Terra Nova	25.7	16.8
China		
Wenchang	23.9	22.4
Libya		
Shatirah	0.5	0.1
	544.3	210.7

Natural Gas	Proved Reserves (bcf)	Production (mmcf/day)
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	153.1	34.9
Foothills Deep Gas area	262.0	101.5
Ram River and Kaybob areas	275.2	67.2
Northwest Alberta Plains		
Rainbow Lake area	295.4	35.9
Peace River Arch	68.6	22.0
Northern Alberta area	313.9	101.1
East Central Alberta		
Provost area	57.8	12.2
North area	142.8	52.8
South area	164.8	53.6
Southern Alberta and Saskatchewan		
South Alberta area	61.5	19.6
South Saskatchewan area	173.2	53.8
Lloydminster Area	80.8	51.2
Other	9.8	4.8
	2,058.9	610.6

The following tables present Husky's finding and development costs for Western Canada and for the total Company for each of the three years ended December 31, 2003 and the aggregate average finding and development costs for the three year period:

Finding and Development Costs

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

Note:

(1) Excludes oil sands and acquisitions/divestitures.

	Year ended December 31,			
Total Company	**2003 - 2001**	**2003**	**2002**	**2001**
Total capitalized costs ($ millions)	4.370.5	1.705.6	1,520.8	1,144.1
Proved reserve additions and revisions (mmboe)	284.0	49.1	114.5	120.4
Average costs per boe	15.39	34.74	13.28	9.50

The following table presents Husky's total crude oil, NGL and natural gas probable reserves for each of the three years ended December 31, 2003, 2002 and 2001:

Probable Oil and Gas Reserves[1]

Probable	Crude Oil & NGL				Natural Gas		
	Western Canada	East coast	International	Total	Western Canada	International	Total
		(mmbbls)				(bcf)	
2003	246.1	182.2	7.0	435.3	381.3	66.5	447.8
2002	246.4	201.6	4.2	452.2	383.9	18.9	402.8
2001	213.0	213.3	4.2	430.5	405.6	18.9	424.5

Notes:

(1) The probable reserves presented have been prepared, using constant prices and costs, in accordance with NI 51-101.

(2) The SEC generally permits oil and gas registrants to disclose only reserves that meet the standards for proved reserves. Due to the higher uncertainty associated with probable reserves, disclosure or reference to probable reserves does not meet the standards for the inclusion in a document filed with the SEC. The disclosure of probable reserves is included herein in accordance with certain undertakings made pursuant to an exemption order granted with respect to Part 8 of NI 51-101.

(3) Bitumen probable reserves are included under the caption Western Canada.

Supplemental Information on Oil and Gas Exploration and Production Activities

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.

Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

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, 2003, 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:

	Canada (1)			International (1)			Total (1)		
Results of operations	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
	($ millions except per boe amounts)								
Revenue									
Sales	2,090	1,738	1,771	310	190	4	2,400	1,928	1,775
Transfers	786	737	390	—	—	—	786	737	390
	2,876	2,475	2,161	310	190	4	3,186	2,665	2,165
Operating expenses									
Productions costs	794	676	617	17	10	—	811	686	617
Depletion, depreciation and amortization	892	813	721	66	38	7	958	851	728
Income taxes	527	387	334	102	64	(1)	629	451	333
Total	2,213	1,876	1,672	185	112	6	2,398	1,988	1,678
	663	599	489	125	78	(2)	788	677	487
Amortization rate in dollars per gross boe	8.43	7.74	7.24	8.00	8.33	80.61	8.40	7.76	7.31

Note:

(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	**2003**	**2002**	**2001**
		($ millions)	
Property acquisition			
Proved (1) — Canada	541	20	366
Unproved — Canada	106	88	55
	647	108	421
Exploration — Canada	298	257	262
— Other	26	9	5
	324	266	267
Development — Canada	1,381	1,127	774
— China	—	66	99
	1,381	1,193	873
	2,352	1,567	1,561

Note:

(1) Property acquisition costs related to corporate acquisitions for proved properties in 2003 included $517 million; 2002 — nil; 2001 included $244 million.

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, 2003, by the year in which the costs were incurred:

Withheld Costs	Total	2003	2002	2001	Prior to 2001
			($ millions)		
Property acquisitions					
Canada	406	56	37	17	296
International	14	—	—	—	14
	420	56	37	17	310
Exploration					
Canada	324	131	40	57	96
International	22	16	6	—	—
	346	147	46	57	96
Development					
Canada	886	477	392	17	—
International	18	1	—	—	17
	904	478	392	17	17
Capitalized interest					
Canada	198	52	26	51	69
	1,868	733	501	142	492

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	2003	2002	2001 (1)
		($ millions)	
Unproved oil and gas properties			
Canada	1,814	1,318	1,052
International	54	37	235
	1,868	1,355	1,287
Proved oil and gas properties			
Canada	11,787	10,207	9,301
International	442	432	159
	12,229	10,639	9,460
	14,097	11,994	10,747
Less accumulated depletion, depreciation and amortization			
Canada	4,633	3,894	3,272
International	250	185	147
	4,883	4,079	3,419
	9,214	7,915	7,328
Net capitalized costs			
Canada	8,968	7,631	7081
International	246	284	247
	9,214	7,915	7,328

Note:

(1) Capital related to 17 mmbbls of proved reserves at Terra Nova transferred to proved oil and gas properties. In 2001, Terra Nova was 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 China and Libya. The Company's proved developed and undeveloped reserves after deductions of royalties are summarized below:

	Canada			International		Total		
Reserves	**Crude Oil & NGL**	**Natural Gas**	**Sulphur**	**Crude Oil & NGL**	**Natural Gas**	**Crude Oil & NGL**	**Natural Gas**	**Sulphur**
	(mmbbls)	(bcf)	(mmlt)	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmlt)
Net proved developed and undeveloped reserves, after royalties (1)(2)(3)(4)								
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
Revisions	18.4	(88.9)	0.1	(2.8)	(100.9)	15.6	(189.8)	0.1
Purchases	9.2	146.2	—	—	—	9.2	146.2	—
Sales	(4.2)	(15.9)	(0.1)	—	—	(4.2)	(15.9)	(0.1)
Discoveries and extensions	32.6	245.6	0.1	—	—	32.6	245.6	0.1
Production	(61.1)	(182.2)	(0.5)	(7.5)	—	(68.6)	(182.2)	(0.5)
End of year 2003	463.0	1,716.6	4.2	22.5	—	485.5	1,716.6	4.2
Net proved developed reserves, after royalties (1)(2)(3)(4)								
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
End of year 2003	372.0	1,422.9	3.8	22.5	—	394.5	1,422.9	3.8

Notes:

(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, 2003 was based on the NYMEX year-end natural gas spot price of U.S. $5.96/mmbtu (2002 — U.S. $4.60/mmbtu; 2001 — U.S. $2.75/mmbtu) and on crude oil prices computed with reference to the year-end WTI price of U.S. $32.51/bbl (2002 — U.S. $31.21/bbl; 2001 — U.S. $19.96/bbl). The price of WTI in Canadian dollars was lower December 31, 2003 than at December 31, 2002 as a result of the Cdn./U.S. dollar exchange rate, which was $1.29 at December 31, 2003 compared with $1.58 at December 31, 2002.

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

	Canada (1)			**International** (1)			**Total** (1)		
Standardized Measure	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
					($ millions)				
Future cash inflows	24,003	25,830	14,102	928	2,719	1,600	24,931	28,549	15,702
Future costs									
Future production and development costs	8,645	7,239	7,541	146	502	523	8,791	7,741	8,064
Future income taxes	5,696	7,278	2,540	247	860	310	5,943	8,138	2,850
Future net cash flows	9,662	11,313	4,021	535	1,357	767	10,197	12,670	4,788
Deduct 10% annual discount factor	4,242	4,966	1,667	117	518	329	4,359	5,484	1,996
Standardized measure of discounted Future net cash flows	5,420	6,347	2,354	418	839	438	5,838	7,186	2,792

Note:

(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.

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.

	Canada (1)			International (1)			Total (1)		
Changes in Standardized Measure	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
					($ millions)				
Present value at January 1	6,347	2,354	5,462	839	438	372	7,186	2,792	5,834
Sales and transfers, net of production costs	(2,097)	(1,802)	(1,556)	(293)	(179)	(2)	(2,390)	(1,981)	(1,558)
Net change in sales and transfer prices, net of development and production costs	(1,379)	7,752	(5,843)	(376)	732	(48)	(1,755)	8,484	(5,891)
Extensions, discoveries and improved recovery, net of related costs	541	676	356	—	40	17	541	716	373
Revisions of quantity estimates	76	(30)	237	(97)	(28)	10	(21)	(58)	247
Accretion of discount	1,055	390	949	130	59	55	1,185	449	1,004
Sale of reserves in place	(47)	(189)	(6)	—	—	—	(47)	(189)	(6)
Purchase of reserves in place	304	45	174	—	—	—	304	45	174
Changes in timing of future net cash flows and other	(237)	(191)	95	(49)	80	10	(286)	(111)	105
Net change in income taxes	857	(2,658)	2,486	264	(303)	24	1,121	(2,961)	2,510
Present value at December 31	5,420	6,347	2,354	418	839	438	5,838	7,186	2,792

Note:

(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.

INDEPENDENT ENGINEER'S AUDIT OPINION

February 2, 2004

Husky Energy Inc.
707 – 8th Avenue S.W.
Calgary, Alberta
T2P 3G7

Gentlemen:

Pursuant to your request we have conducted an audit of the reserves estimates and the respective present worth value of these reserves of Husky Energy Inc., as at December 31, 2003. The Company's detailed reserves information was provided to us for this audit. Our responsibility is to express an independent opinion on the reserves and respective present worth value estimates, in aggregate, based on our audit tests and procedures.

We conducted our audit in accordance with Canadian generally accepted standards as described in the Canadian Oil and Gas Evaluation Handbook (COGEH) and auditing standards generally accepted in the United States of America. Those standards require that we review and assess the policies, procedures, documentation and guidelines of the Company with respect to the estimation, review and approval of Husky's reserves information. An audit includes examining, on a test basis, to confirm that there is adherence on the part of Husky's internal reserve evaluators and other employees to the reserves management and administration policies and procedures established by the Company. An audit also includes conducting reserves evaluation on sufficient number of Company properties as considered necessary to express an opinion.

Based on the results of our audit, it is our opinion that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B. H. Emslie

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

REPORT ON RESERVES DATA BY QUALIFIED RESERVES EVALUATOR

To the Board of Directors of
HUSKY ENERGY INC. (the ''Company''):

1. Our staff has evaluated the Company's oil and gas reserves data as at December 31, 2003. The reserves data consist of the following:

   (a) proved oil and gas reserve quantities estimated as at December 31, 2003 using constant prices and costs; and

   (b) the related standardized measure of discounted future net cash flows.

2. The oil and gas reserves data are the responsibility of the Company's management. As the Corporate Representatives our responsibility is to certify that the reserves data has been properly calculated in accordance with generally accepted procedures for the estimation of reserves data.

3. We carried out our evaluation in accordance with generally accepted procedures for the estimation of oil and gas reserves data and standards set out in the Canadian Oil and Gas Evaluation Handbook (the ''COGEH'') with the necessary modifications to reflect definitions and standards under the applicable U.S. Financial Accounting Standards Board standards (the ''FASB Standards'' and the legal requirements of the U.S. Securities and Exchange Commission (''SEC Requirements''). Our internal reserves evaluators are not independent of the Company, within the meaning of the term ''independent'' under those standards.

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the oil and gas reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGEH as modified or replaced by the FASB Standards and SEC Requirements.

5. The following sets forth the estimated standardized measure of discounted future net cash flows (before deducting income taxes) attributed to proved oil and gas reserve quantities, estimated using constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2003:

Location of Reserves	Discounted Future Net Cash Flows (before income taxes, 10% discount rate)
Canada	5,420
China	411
Libya	7
	5,838

   We have filed the Company's disclosures in accordance with Financial Accounting Standards Board Statement No. 69 reserve disclosure concurrently with this form.

6. In our opinion, the oil and gas reserves data evaluated by us have, in all material respects, been determined in accordance with principles and definitions presented in the COGEH as modified or replaced by the FASB Standards and SEC Requirements.

7. We have no responsibility to update our evaluation for events and circumstances occurring after the date of this report.

8. Oil and gas reserves are estimates only, and not exact quantities. In addition, the oil and gas reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

/s/ PRESTON KRAFT

Preston Kraft P.Eng
Manager of Reservoir Engineering
Calgary, Alberta
February 2, 2004

/s/ LARRY BELL

Larry Bell
Vice President, Exploration & Production Services
Calgary, Alberta
February 2, 2004

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Husky Energy Inc. (the ''Company'') are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes oil and gas reserves data, which consist of the following:

(1) proved oil and gas reserve quantities estimated as at December 31, 2003 using constant prices and costs; and

(2) the related standardized measure of discounted future net cash flows.

Our oil and gas reserves evaluation process involves applying generally accepted procedures for the estimation of oil and gas reserves data for the purposes of complying with the legal requirements of the U.S. Securities and Exchange Commission (''SEC'') and the applicable provisions of the U.S. Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69 (collectively, the ''Oil and Gas Reserves Data Process''). Our Manager of Reservoir Engineering, who is an employee of the Company, has evaluated the Company's oil and gas reserves data and certified that the Reserves Data Process has been followed. The Report on Reserves Data of the Manager of Reservoir Engineering and Vice President, Exploration and Production Services will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors has:

(a) reviewed the Company's procedures for providing information to the internal and external qualified oil and gas reserves evaluators;

(b) met with the internal and, if applicable, external qualified oil and gas reserves evaluator(s) to determine whether any restrictions placed by management affect the ability of the internal qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the internal qualified oil and gas reserves evaluators.

The Audit Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Audit Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the Report on Reserves Data of the Manager of Reservoir Engineering; and

(c) the content and filing of this report.

The Company has sought and was granted by securities regulatory authorities an exemption from the requirement under securities legislation to involve independent qualified oil and gas reserves evaluators or auditors. Notwithstanding this exemption, we involve independent qualified reserve auditors as part of our corporate governance practices. Such independent auditors audited over 75% of reserves data and reviewed the remaining proved and probable oil and gas reserves based on value. Their involvement helps assure that our internal oil and gas reserves estimates are materially correct.

In our view, the reliability of the internally generated oil and gas reserves data is not materially different than would be afforded by our involving independent qualified reserves evaluators to evaluate and review the reserves data. A portion of our oil and gas reserves data is international in nature. Husky is an SEC registrant and therefore our reserves data is developed in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as modified or replaced by the applicable U.S. Financial Accounting Standards Board standards and the legal requirements of the SEC. Our procedures, records and controls relating to the accumulation of source data and preparation of reserves data by our internal reserves evaluation staff have been established, refined and documented over many years. Our internal reserves evaluation staff includes 106 individuals, including support staff, of whom 65 individuals are qualified reserves evaluators as defined in the Canadian Oil and Gas Evaluation Handbook, with an average of 15 years of relevant experience in evaluating reserves. Our internal reserves evaluation management personnel includes 25 individuals with an average of 14 years of relevant experience in evaluating oil and gas and managing the evaluation process.

Reserves data are estimates only, and are not exact quantities. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

/s/ JOHN C. S. LAU	March 18, 2004
John C. S. Lau *President & Chief Executive Officer*	
/s/ NEIL D. MCGEE	March 18, 2004
Neil D. McGee *Vice President & Chief Financial Officer*	
/s/ MARTIN J. G. GLYNN	March 18, 2004
Martin J. G. Glynn *Director*	
/s/ R. DONALD FULLERTON	March 18, 2004
R. Donald Fullerton *Director*	

Description of Major Properties and Facilities

Husky's portfolio of assets includes properties that produce light (30° API and lighter), medium (between 20° and 30° API and heavy (below 20° and above 10° API) gravity crude oil, NGL, natural gas and sulphur. Production figures include daily production from Marathon properties based on the period October 1, 2003 to December 31, 2003.

At December 31, 2003, Husky had gross proved crude oil and NGL reserves totalling 544.3 mmbbls (485.5 mmbbls net) and gross proved natural gas reserves totalling 2,058.9 bcf (1,716.6 bcf net).

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 85% 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 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.

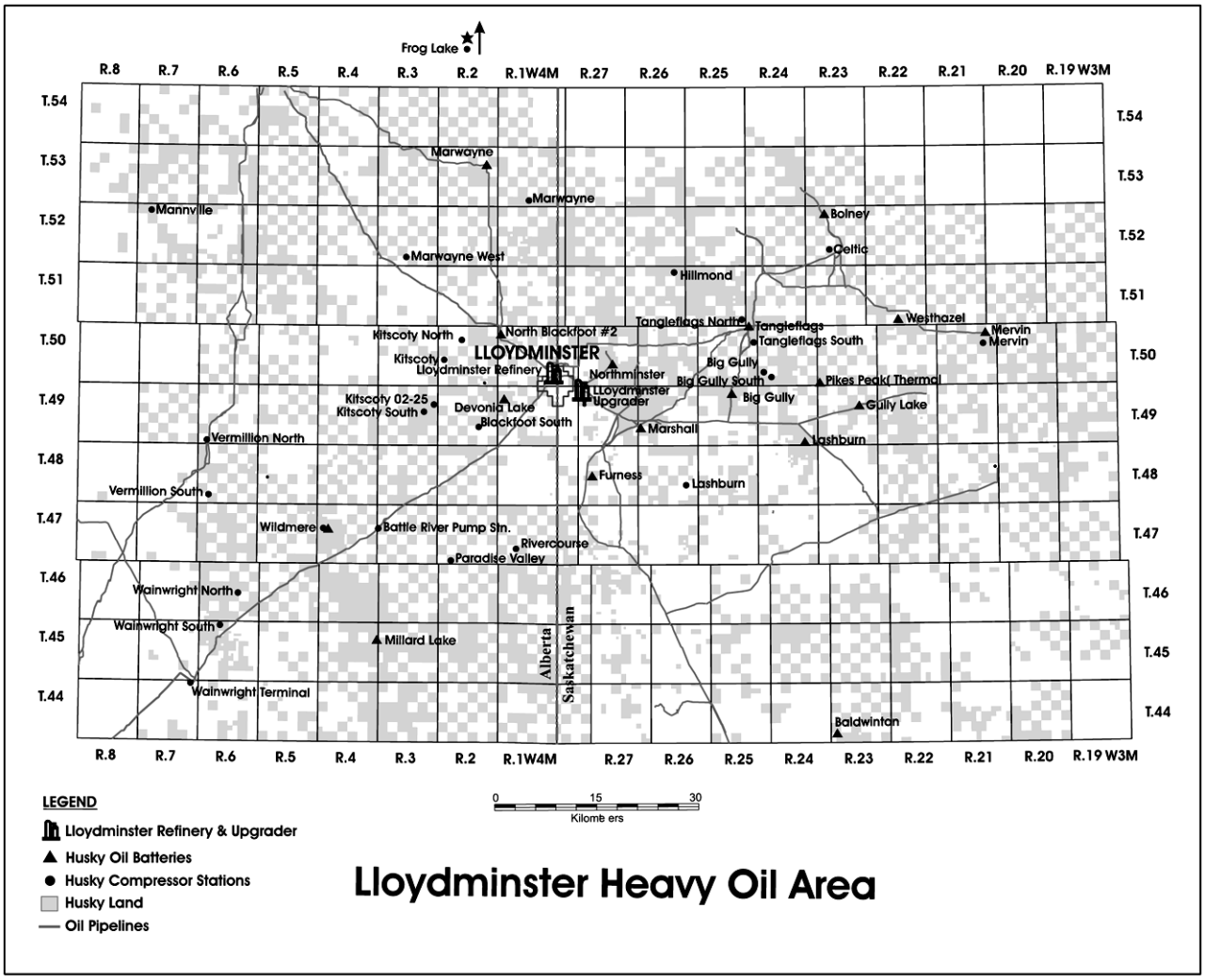
Husky currently produces from oil and gas wells ranging in depth from 450 to 650 metres and holds a 100% working interest in the majority of these wells. Husky produces heavy oil from the Lloydminster area using a variety of techniques, including standard primary production methods, as well as steam 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 89.8 mbbls/day in 2003. Approximately 70.9 mbbls/day of that total was primary production of heavy crude oil, approximately 14.8 mbbls/day was production from Husky's thermal operations at Pikes Peak (cyclic steam) and Bolney/Celtic (SAGD) and approximately 4.1 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.

In the Lloydminster area 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 numerous small shallow natural gas pools in the Lloydminster area (approximately 1 to 2 bcf of proved reserves). Husky's total gross natural gas production from the area during 2003 was 51.2 mmcf/day.

Lloydminster Area



Northwest Alberta Plains

Rainbow Lake Area

Rainbow Lake, located approximately 700 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. These methods 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 2003, Husky initiated the recovery of natural gas from several pools. NGL recovery is forecast to begin in the 2008-2010 timeframe and is expected to generate revenues as the crude oil production from the pools is completed. Husky uses horizontal drilling techniques, including the re-entry of existing wellbores, to maintain the level of crude oil production and to increase recovery rates. Husky plans to continue exploration efforts to supplement its development initiatives in the Rainbow Lake area. Husky's gross production from this area averaged 7.7 mbbls/day of light crude oil and NGL and 33.6 mmcf/day of natural gas during 2003.

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. During 2003, a 20 mmcf/day sales gas compressor and a sales gas coalescer were added to the plant, increasing sales gas capacity from 17 mmcf/day to 34 mmcf/day. The area serviced by the Rainbow plant was expanded in 2003 with the construction of a 16.5 centimetre diameter gathering system into the Bivouac area in north-eastern British Columbia, where Husky operates gas wells and a compressor station.

Husky acquired two significant non-operated properties in the Rainbow area through the acquisition of Marathon. They included the Ekwan/Sierra property in north-eastern British Columbia and the Bistcho/Cameron Hills property straddling the Alberta and Northwest Territories border. Husky's gross production from these properties currently averages 9 mmcf/day of natural gas and 68 bbls/day of liquid hydrocarbons. Husky also acquired a working interest in the Encana Sierra gas plant and the Paramount Bistcho gas plant. Husky is active in both these areas with development and exploration drilling. These two areas have growth potential with 95,000 net undeveloped acres at Ekwan/Sierra and 110,000 net undeveloped acres at Bistcho/Cameron Hills.

Peace River Arch Area

The Peace River Arch area of northern Alberta, which includes the Slave Lake, Sawn Lake, Red Earth, Lubicon, Nipisi, Utikuma and other properties, has been 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 net production from properties in this area, at approximately 3.8 mbbls/day of crude oil, through acquisitions, step-out drilling and waterflood optimization. With Husky's acquisition of Marathon in 2003, the Slave Lake and Red Earth properties were added to the asset base, increasing 2003 gross liquid production by approximately 1,160 bbls/day and natural gas production by 10.3 mmcf/day. The average working interest in these lands is 80%, for a net 166,200 acres. Infrastructure includes a 100% working interest in a 30 mmcf/day sour gas plant and three oil batteries. Husky plans to continue development drilling and waterflood optimization 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 close to 100% working interest in approximately 623,000 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 three wells per section. Husky intends to continue to develop this area by drilling undeveloped sections, infill drilling, land acquisitions and step out exploration. Gross production from this area in 2003 averaged 32 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, step-out 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 8.9 mmcf/day of natural gas in 2003.

Marten Hills/Muskwa Area

The Marten Hills and Muskwa areas of Alberta are 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, step-out 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 gas compressor stations (compressors at sales points) and a number of field booster 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. Gross production from this area averaged 35.9 mmcf/day of natural gas in 2003.

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, step-out and exploratory drilling so that existing pools can be optimized and new pools can be placed on production.

Husky holds working interests ranging from 60-95% 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 37.8 mmcf/day of natural gas in 2003.

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 4.5 mmcf/day of natural gas in 2003.

Northeast British Columbia and Alberta 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 105 mmcf/day. Husky holds a 34% interest in two unitized wells, a 24% and a 50% interest in two non-unit wells, 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 2003, the plant operated at approximately 86% of its design rate capacity. The Ram River plant processes in excess of 10% of Husky's total gross natural gas production, which includes an average of 48 mmcf/day of Husky gross sales gas from the Blackstone, Brown Creek, Cordel and Stolberg fields and an average of 22 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 the Ferrier area, which is processed at another gas plant, averaged 5.7 mmcf/day of natural gas bringing the total Husky interest production of natural gas from the Ram River area to 64 mmcf/day in 2003.

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.

Kaybob

The Kaybob area was acquired through Husky's acquisition of Marathon on October 1, 2003. The Kaybob area consists of lands located in the Fox Creek area of Alberta. The Kaybob area consists of four main areas. These are:

- Kaybob South Beaverhill Lake Unit 1 (35.6% working interest)
- Kaybob South Triassic Unit 1 (40.5% working interest)
- Kaybob South Triassic Unit 2 (26.8% working interest)
- Non-unit lands (various, from gross overriding royalty to 100% working interest)

The majority of the gas is gathered and processed through the Kaybob South Amalgamated Gas Plants 1 and 2. Husky has an approximate 17.8% working interest in the sour portion and an approximate 20.4% working interest in the sweet gas portion of the plant. Husky also has various working interests in sweet gas gathering and compression facilities in the area. Husky's gross production from the area is 525 bbls/day of oil, 650 bbls/day of NGL and 13 mmcf/day of natural gas during 2003.

Boundary Lake Area

Husky holds a 50% working interest in the Boundary Lake Gas Unit and 34% and 19% interest in the Boundary Lake oil unit 1 and 2, respectively, 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 14.5 mmcf/day of natural gas and 1.9 mbbls/day crude oil and NGL from the Boundary Lake units during 2003.

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, NGL and natural gas. Husky's gross production from these properties averaged 4.4 mbbls/day of crude oil and NGL and 6.1 mmcf/day of natural gas in 2003.

Kakwa Area

Husky acquired, through the acquisition of Marathon, an average 60% working interest in oil and gas processing facilities and associated oil and gas gathering systems in the Kakwa area. Husky operated lands in the Kakwa area total approximately 47,700 gross acres. Husky has an interest in approximately 65 Cardium wells in this area with average gross production of 11.1 mmcf/day of natural gas, 508 bbls/day NGL and 485 bbls/day of oil in 2003.

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 113% of design capacity and is processing approximately 124 mmcf/day of total plant sales gas and 39 mbbls/day of NGL. The plant and liquid acceleration gas recycle plant were at 87% capacity in 2003 which resulted in Husky gross production of 4.4 mbbls/day NGL and 13.6 mmcf/day natural gas in 2003.

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 160 Cardium wells in this area that averaged gross production of 35.1 mmcf/day of natural gas and 1.7 mbbls/day of NGL in 2003.

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 23.3 mmcf/day of natural gas from four wells in 2003. The production flows through Husky owned gathering systems for processing at third party plants at Sikanni and McMahon.

Graham Area

Husky acquired, through the acquisition of Marathon, a 40% working interest in approximately 71,000 gross acres of developed and undeveloped lands in the Graham area of north-eastern British Columbia. The property produced at an average of 10.4 mmcf/day gross natural gas sales in 2003 from a total of 22 wells. Production from the property is from one Halfway and seven Baldonnel pools. Husky also acquired interests in two 1,500 horsepower compressor stations and the non-operated Cypress gas plant. Plant capacity is 45 mmcf/day and the plant is currently operating at full capacity. Husky holds a 33.2% interest in the gas treating unit, 28.2% interest in the amine unit and 28% interest in the sulphur unit.

East Central Alberta

Athabasca Area

The Athabasca area extends approximately 175 kilometres north of Edmonton 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 pipeline system and an average working interest of 90% in the producing wells. Husky holds approximately 539,000 net acres of undeveloped land and 409,000 net acres of developed land in this area. 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 52.8 mmcf/day of natural gas and 682 bbls/day of crude oil in 2003.

Red Deer and Hussar Area

The core of the Red Deer and Hussar area is between Calgary, Drumheller and Sylvan Lake. Husky operates 18 facilities with gas gathering systems in this area. Gross production from this area averaged 53.7 mmcf/day of natural gas and crude oil and NGL of 2.7 mbbls/day in 2003. 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. In 2003 Husky participated in a coal bed methane pilot project. In 2004, Husky will develop a commercial coal bed methane project, based on the successful results of the pilot project.

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 20.8 mbbls/day of crude oil and 12.2 mmcf/day of natural gas in 2003. Husky intends to selectively drill lower risk oil locations and focus on managing operating costs and improving oil recovery. In 2004 Husky intends to develop several of its 2003 natural gas discoveries. There is significant competition in the area for land as well as infrastructure. Husky has a large land position and maintains close to 100% working interest in most of its facilities.

Southern Alberta and Southern Saskatchewan

As of December 31, 2003, the Company held 250,000 net developed acres and 1.1 million undeveloped acres in Southern Saskatchewan and 280,000 net developed acres and 240,000 net undeveloped acres in Southern Alberta. The Company also has a small landholding in Manitoba.

Southern Saskatchewan Area

Husky is a prominent operator in southern Saskatchewan primarily producing medium gravity crude oil, with some natural gas and light crude oil. Gross production from this area averaged 18.4 mbbls/day of crude oil and of 53.8 mmcf/day of natural gas during 2003.

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.

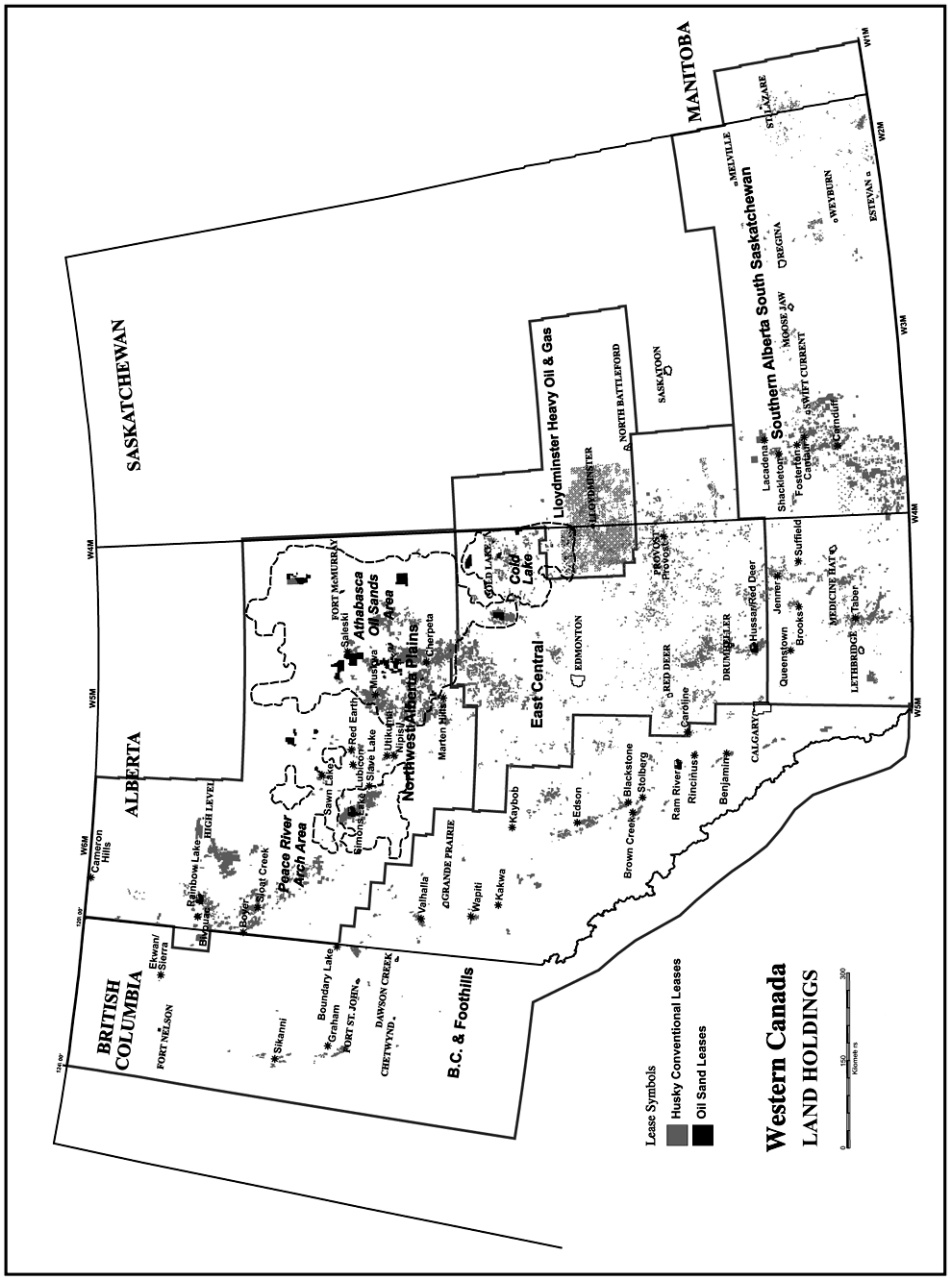
At the Shackleton/Lacadena Milk River shallow gas project, 128 wells were drilled and one new gas facility was built in 2003. The project was producing at a rate of 52 mmcf/day at December 31, 2003 from a total of 225 wells. In 2004, Husky plans to drill 100 additional wells and construct one natural gas processing facility.

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. Gross production from this area averaged 11.7 mbbls/day of crude oil and 14.6 mmcf/day of natural gas during 2003.

The acquisition of Marathon on October 1, 2003 added a new core area at Queenstown that includes five natural gas facilities producing over 20 mmcf/day. Husky intends to drill 40 wells in this area in 2004.

Western Canada



Athabasca, Cold Lake and Peace River

Oil Sands

Husky currently holds interests in 433,610 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 projects, 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 Sunrise (formerly Kearl) areas.

In addition to interests in the 353,930 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 Sands Area	Gross Acres	Net Acres	Husky Operator
South Athabasca — overriding royalty	Athabasca	35,601	—	No
South Athabasca	Athabasca	22,032	11,016	Yes
Sunrise — In situ (1)	Athabasca	64,034	64,034	Yes
Misthae (Drowned, Martin Hills W. & Spur)	Athabasca	28,160	28,160	Yes
Saleski	Athabasca	154,880	154,880	Yes
Hoole — overriding royalty	Athabasca	47,040	—	No
Beaverdam	Cold Lake	11,520	11,520	Yes
Caribou (2)	Cold Lake	35,840	35,840	Yes
Lobstick	Cold Lake	37,120	37,120	Yes
Tucker (3)	Cold Lake	11,360	11,360	Yes
Panny (Senex & Welstead)	Peace River	47,360	47,360	Yes
Peace River (Cadotte Lake)	Peace River	11,840	11,840	Yes
Sawn Lake (Loon)	Peace River	20,480	20,480	Yes
		527,267	433,610	

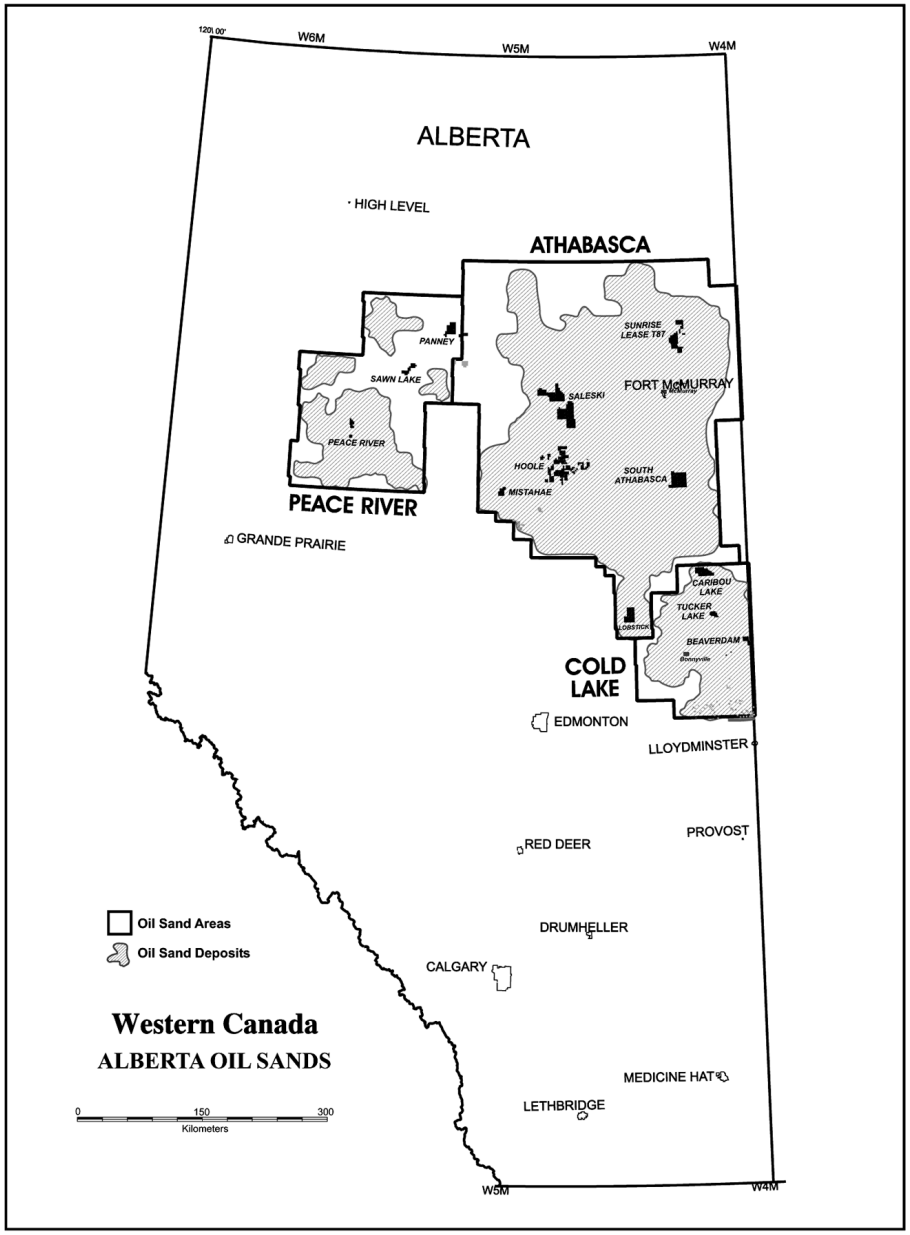
Notes:

(1) Included in the gross and net amounts are an additional 6,400 acres of petroleum and natural gas rights held as protection acreage for gas over bitumen issues. In 2003, the Alberta regulatory authority issued General Bulletin GB 2003-28 that required natural gas wells within certain bitumen prone areas to be shut-in. The production of natural gas where natural gas reservoirs were believed to be in pressure contact with bitumen reserves was deemed to present an unacceptable risk to future in-situ bitumen production. Sunrise was formerly named Kearl.

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

(3) Included in the gross and net amounts are an additional 1,280 acres of petroleum and natural gas rights held as protection acreage for gas over bitumen issues.

Oil Sands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ATHABASCA
PANNEY
SAWN LAKE
PEACE RIVER
PEACE RIVER
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FORT McMURRAY
SALESKI
HOOLE
MISTAHAE
SOUTH ATHABASCA
GRANDE PRAIRIE
CARIBOU LAKE
TUCKER LAKE
LOBSTICK
BEAVERDAM
COLD LAKE
EDMONTON
LLOYDMINSTER
PROVOST
RED DEER
DRUMHELLER
CALGARY
MEDICINE HAT
LETHBRIDGE
Oil Sand Areas
Oil Sand Deposits
Western Canada
ALBERTA OIL SANDS
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300
Kilometers
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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 and Labrador, 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 working interests ranging from 5.33% to 90% in 14 Significant Discovery License areas in the Jeanne d'Arc Basin. Husky is also the operator of seven Exploration Licenses (''EL'') on the Grand Banks and two in the South Whale Basin. 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 exploration and 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.

Husky will continue technical evaluation of its East Coast exploration acreage. Depending on drilling rig availability, Husky plans to drill one exploration type stratigraphic test well in 2004 on the EL1059 block in the South Whale 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.

As at December 31, 2003, there were eight development wells drilled in the Graben area, five producing wells and three injection wells. In the East Flank area there were seven development wells including four production wells and three injection wells. Drilling operations are expected to continue based on an updated 36 well depletion plan for the Graben and East Flank areas. A 2001 delineation well in the Far East area encountered 82 metres of net pay confirming the reservoir sands extend to this area in 2003. A second well, that was intended to be a water injection well, was drilled in the Far East area. 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. During 2003, a third delineation well was drilled to assess the northern fault blocks. The well encountered water suggesting a common oil-water contact throughout the Far East reservoir. Additional delineation wells in the Far East area are currently being considered as part of the 2004 drilling program. At December 31, 2003, Husky had booked 17.2 mmbbls of gross light crude oil to the proved developed category and 8.5 mmbbls proved undeveloped. 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 is 12.51%. This interest is subject to change, pending redetermination once the field has been further delineated. Production at Terra Nova commenced in January 2002. Husky's gross production from Terra Nova averaged approximately 17.8 mbbls/day in the fourth quarter of 2003. Husky's gross share of production from Terra Nova was 6.1 mmbbls in 2003.

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 oil field on the eastern section of the Jeanne d'Arc basin.

During 2003, progress was achieved in several areas of the White Rose development project. All of the glory holes were excavated in the seabed to the required nine metre depth. The glory holes will protect the subsea wellhead equipment and associated production facilities from scouring icebergs. With the glory hole completion, development drilling has commenced for the White Rose oil field and will consist of nine wells prior to first oil — four producing wells, four water injection wells and one gas injection well, to be completed over the next two years.

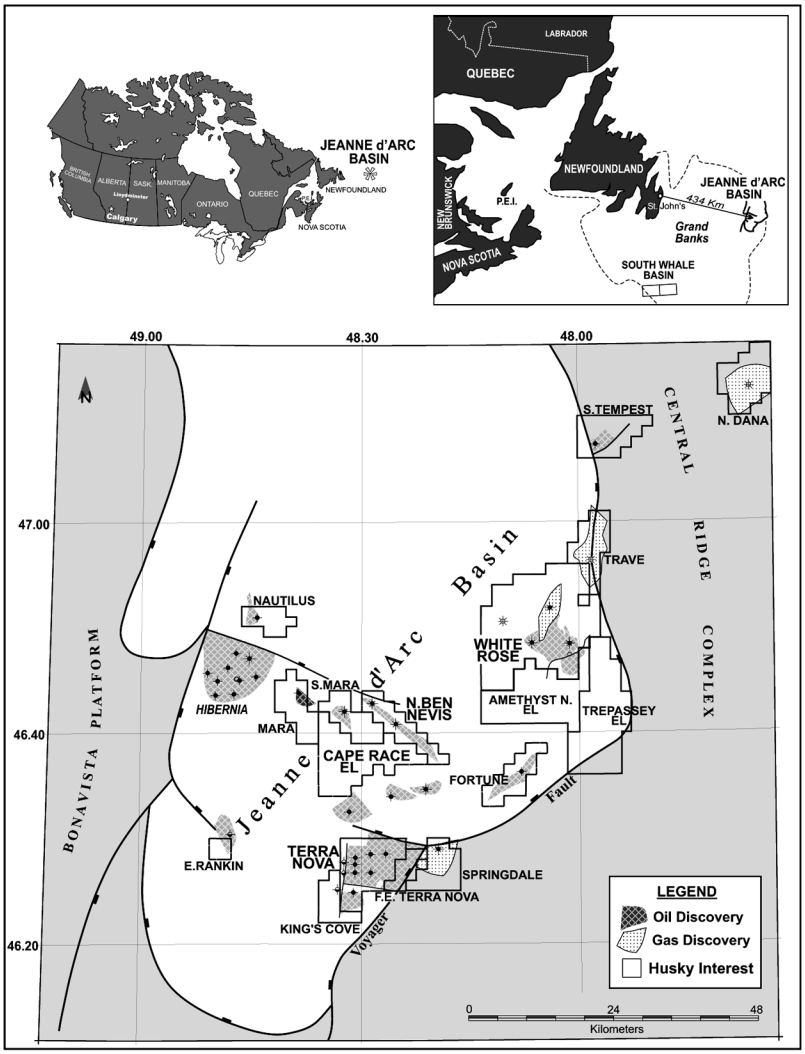
The hull of the FPSO was launched in South Korea in July 2003. The turret, which was fabricated in Abu Dhabi, was successfully transported to South Korea in mid-August and now has been installed in the FPSO. The FPSO is expected to arrive in Marystown, Newfoundland and Labrador in the second quarter of 2004 where the installation of the topsides, hook up and commissioning will take place. The FPSO topsides are being engineered and fabricated in St. John's and Marystown, Newfoundland and Labrador. Fabrication of the subsea production systems, including risers, flowlines and umbilicals, manifolds and wellheads are well under way. The first subsea well head assembly was completed in 2003.

Current plans provide for a total of 19 to 21 development wells to be drilled to recover crude oil over a 10 to 15 year period. Peak production is expected to be approximately 92,000 barrels of oil per day sustained for approximately four years before declining.

Also in 2003, a delineation well, White Rose F-04, was drilled on a separate geological structure at the southern end of the White Rose oil field. The initial F-04 well encountered approximately 180 metres of hydrocarbon bearing sandstone, comprising 140 metres of gas and 40 metres of oil. Husky and its co-venturer drilled a successful sidetrack location (F-04Z) to delineate the structure. In 2004, planning and design work will begin to determine the optimum method of producing the oil reserves from the F-04 structure through the White Rose FPSO.

East Coast

Grand Banks — Jeanne d'Arc Basin



International

South China Sea

Wenchang

The Wenchang oil field is located in the western Pearl River Mouth Basin, approximately 300 kilometres south of Hong Kong and 135 kilometres east of Hainan Island. The Company holds a 40% working interest in the project and spent approximately $253 million, including acquisition costs, to first oil. Production commenced in July 2002. The Wenchang 13-1 and 13-2 oil fields are producing from 21 wells in 100 metres of water into a floating production, storage and offloading vessel stationed between fixed platforms located in the fields. The blended crude oil from the two fields averages approximately 35° API, similar to the benchmark Minas blend. At December 31, 2003, Husky's proved reserves at Wenchang were calculated to be 23.9 mmbbls of crude oil. Husky's gross production averaged 22.4 mbbls/day during 2003.

Block 39/05

Husky executed a production sharing contract with China National Offshore Oil Corporation (''CNOOC'') for the 5,700 square kilometres 39-05 Exploration Block surrounding the Wenchang 13½ fields with a commencement date of October 1, 2001. 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 type stratigraphic well was plugged and abandoned without testing and in February 2003, the Wenchang 8-1-1 exploration type stratigraphic well was plugged and abandoned without testing. Husky is evaluating the geological information for this block and expects to complete this assessment by the end of 2004.

Blocks 23/15 and 23/20

Husky executed production sharing contracts with CNOOC for the 23-15 and 23-20 exploration blocks with a commencement date of December 1, 2002. Both contract areas are located in the South China Sea north of Hainan, within 80 kilometres of the Weizhan oil fields. The 23-15 block is 1,327 square kilometres and the 23-20 block is 1,543 square kilometres. The work program requires Husky to drill a single exploration well on each block within three years. CNOOC has the right to participate in development of any discoveries up to a 51% working interest. In 2003, Husky completed a 1,000 square kilometre 3-D seismic survey shot over a portion of block 23-15. This survey has been processed and is now being interpreted. Technical evaluations are currently underway to determine a possible seismic survey on block 23-20 in 2004.

Block 40/30

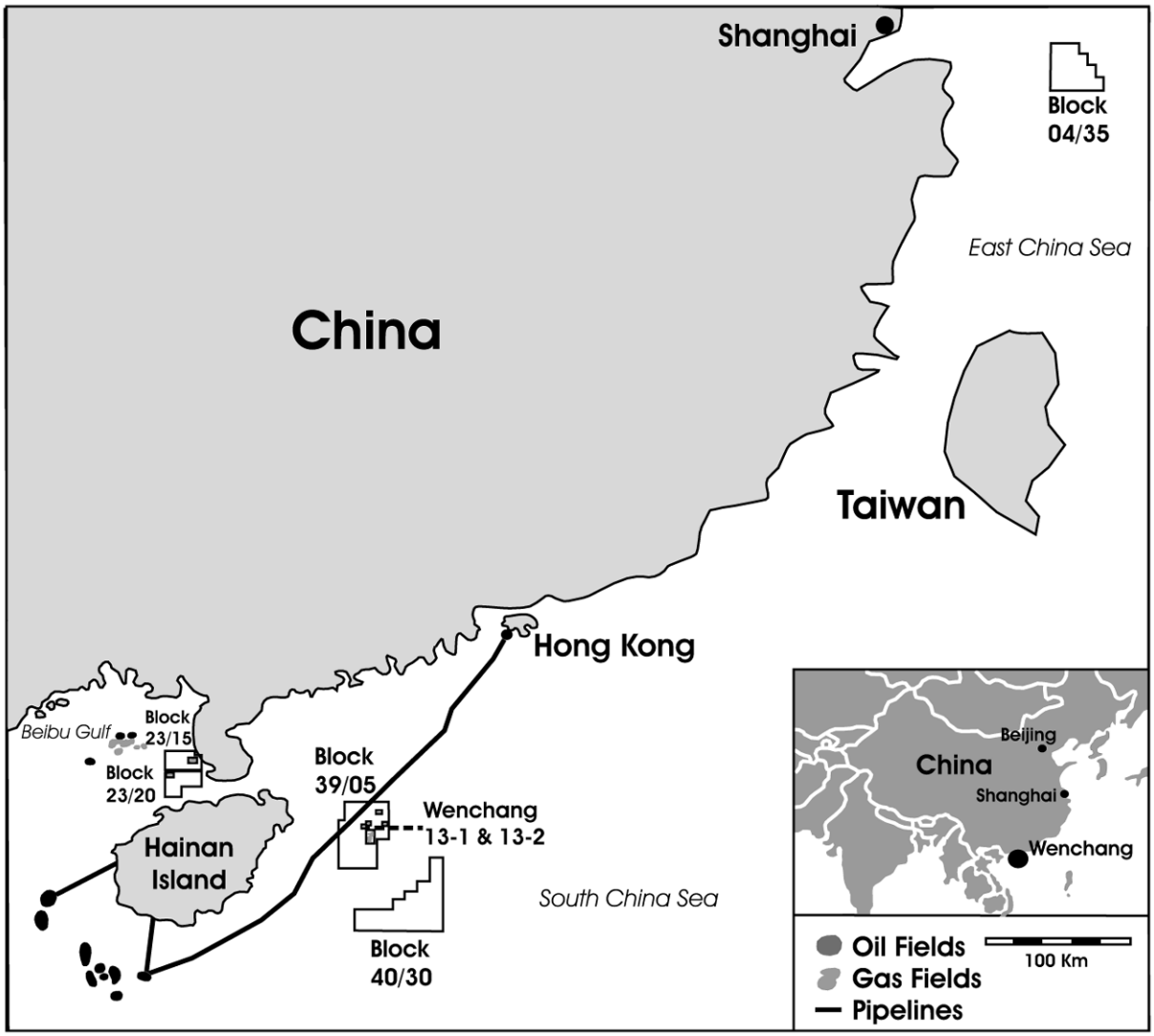
Husky executed a production sharing contract with CNOOC for the 40-30 exploration block with a commencement date of February 1, 2003. The block is located in the South China Sea approximately 100 kilometres south of the 13-1 and 13-2 oil fields. The block covers an area of 6,704 square kilometres. The production sharing contract requires the drilling of one exploration well within three years and has a minimum work commitment of U.S. $10 million. CNOOC has the right to participate in development of any discoveries up to a 51% working interest. A deep-water drilling rig has been contracted for one well, the ChangChang 12-1-1, which will commence drilling in the first half of 2004.

East China Sea

Block 04/35

Husky executed a production sharing contract with CNOOC for the 04-35 exploration block with a commencement date of December 1, 2003. The block is located in the East China Sea approximately 350 kilometres east of the city of Shanghai and covers an area of 4,835 square kilometres. The production sharing contract requires the drilling of a single exploration well to a depth of 2,500 metres within three years and a minimum work commitment of U.S. $3 million. Technical evaluations of the hydrocarbon potential have commenced. CNOOC has the right to participate in development of any discoveries up to a 51% working interest.

China



Madura Strait, Indonesia

Husky is party to a production sharing contract (''PSC''), which provides for various cost and production sharing arrangements, relating to a 2,794 square kilometre 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. Construction of the power plant did not proceed due to economic issues that occurred in Indonesia shortly after the natural gas sales contract was signed. In 2003 the natural gas sales contract was cancelled with the approval of the Indonesian authorities. In January 2003, Husky signed a memorandum of understanding to begin discussions intended to finalize another natural gas sales agreement for the Madura production. Negotiations progressed during 2003. Assuming successful negotiation of the gas sales agreement, a revised Plan of Development will be submitted to the Indonesian regulatory authority for approval. At December 31, 2003, the calculated proved undeveloped reserves at Madura, which totalled 142.9 bcf of natural gas and 6.4 mmbbls of natural gas liquids, were removed from the proved category pending the completion of a new gas sales contract and negotiation with the Indonesian regulatory authority for an extension to the PSC.

Shatirah, Libya

Husky has an interest in a small 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 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,		
	2003	2002	2001
		(mmcf/day)	
Sales to end users			
United States	382	375	413
Canada	156	115	106
	538	490	519
Sales to aggregators	43	49	40
Internal use (1)	30	30	14
	611	569	573

Note:

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

Husky also markets third party natural gas production in addition to its own production.

Delivery Commitments

The following table shows the future commitments to deliver natural gas from Husky's reserves in Western Canada. Husky's proved developed reserves of natural gas in Western Canada are more than adequate to meet future delivery commitments.

	Fixed Price		Market Price
	Bcf	$/mmbtu	Bcf
2004	25.5	3.26	51.1
2005	25.5	3.60	26.3
2006	25.5	3.76	23.6
2007	20.0	4.36	16.9
2008	20.0	4.60	4.9
2009	20.0	4.85	0.5
2010	20.0	5.12	—
2011	20.0	5.41	—
2012	20.0	5.73	—
2013	20.0	6.06	—
2014	6.2	3.72	—
	222.7		123.3

Midstream Operations

Overview

The midstream operations of Husky include:

- Upgrading — the upgrading of heavy crude oil feedstock into synthetic crude oil;
- Infrastructure — 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; and
- Marketing — the purchase and marketing of Husky's and other producers' crude oil, natural gas, NGL, sulphur, petroleum coke and electrical power.

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.

The Husky Lloydminster Upgrader provides heavy crude oil access to a new market, which Husky believes has facilitated, and will continue to stimulate, heavy oil production in the area. The market for heavy crude oil previously was either as feedstock for asphalt production or it was sold as blended heavy crude oil for feedstock for specific refineries designed to process or upgrade heavier crude oils. 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 exceeds 61 mbbls/day of synthetic crude oil. Production at the upgrader averaged 61.4 mbbls/day of synthetic crude oil and 10.9 mbbls/day of diluent in 2003 compared with 55.7 mbbls/day of synthetic crude oil and 9.7 mbbls/day of diluent in 2002. Throughput at the upgrader in 2003 was higher than 2002 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 340 lt/day of sulphur and 760 lt/day of petroleum coke during 2003. 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 2,050 kilometres of pipeline and are capable of transporting in excess of 575 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 from the field 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:

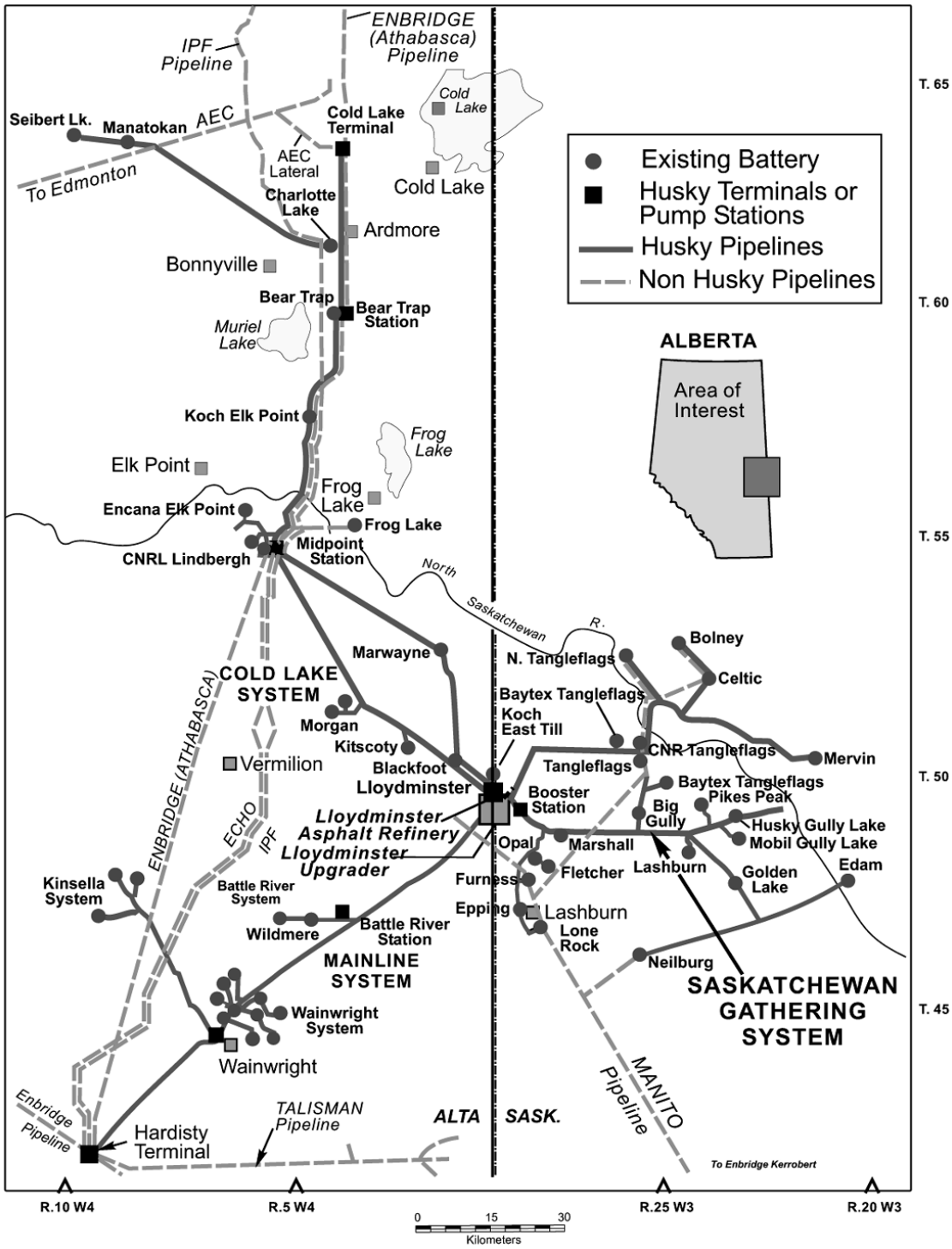
	Years ended December 31,		
	2003	2002	2001
		(mbbls/day)	
Combined pipeline throughput	484	457	537

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.

Heavy Oil Pipeline Systems



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 effective in 1999. 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 under 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.

Commodity 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 gas sales 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 (30%), mid-west United States (37%), Western Canada (29%) and west coast United States (4%). The natural gas volumes sales contracted are primarily at market price (90%). The terms of the contracts remaining at December 31, 2003 are up to one year (74%), one year to five years (16%) and over five years (10%). Husky has acquired rights to firm pipeline capacity to transport the natural gas to most of these markets.

Husky has developed its commodity marketing operations to include the acquisition of third party volumes in order to 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 and marketed directly or through Husky's 10 terminals located throughout Western Canada.

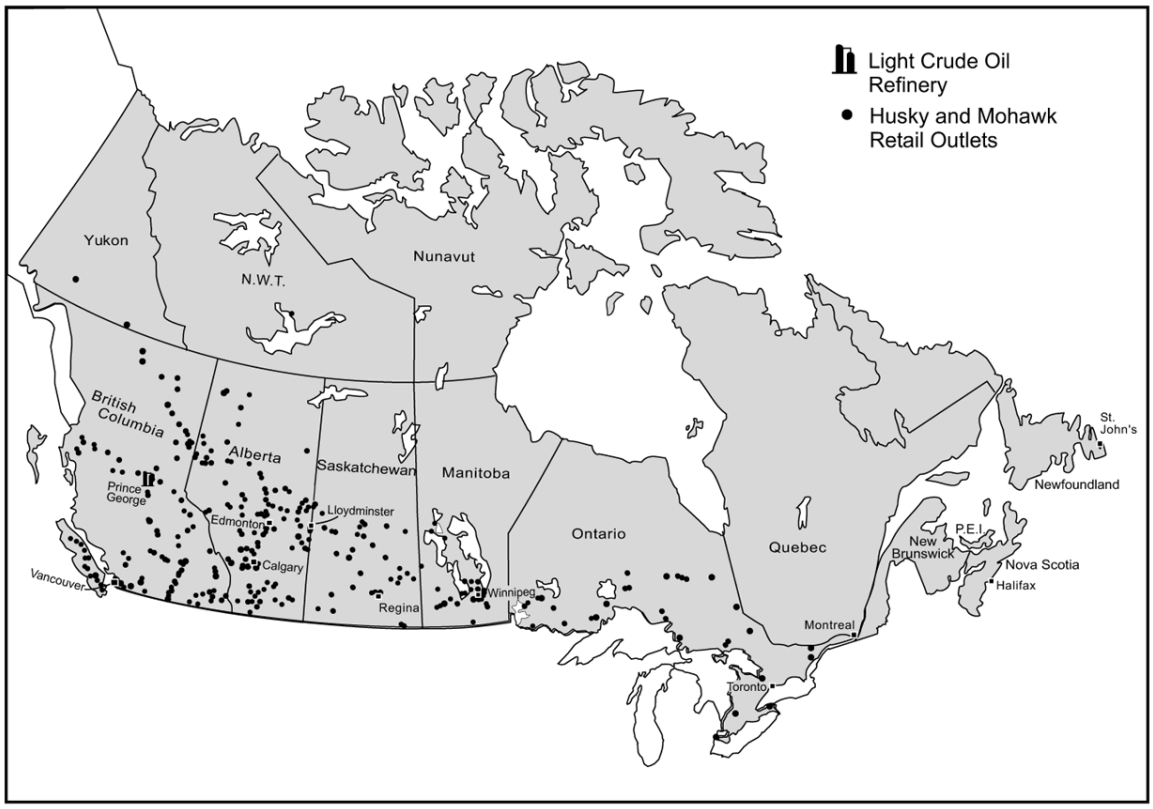
Branded Petroleum Outlets and Commercial Distribution

Distribution

As of December 31, 2003, there were 550 independently operated Husky and Mohawk branded petroleum outlets and two independent restaurants. These petroleum outlets include service stations, travel centres and bulk distribution facilities located from Vancouver Island on the West Coast of Canada to the eastern border of Ontario. The travel centre 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 travel centre 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.

Retail Marketing System

Branded Petroleum Outlets



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 Fuel'' and additive enhanced ''Diesel Max'' are offered in all markets together with Chevron lubricants. Husky supplies refined petroleum products to its branded independent retailers on an exclusive basis and provides financial and other assistance for location improvements, marketing support and related services. Husky's brands are promoted through the Husky Snowstars Program, 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, 2003:

Retail Outlets	British Columbia & Yukon	Alberta	Sask.	Manitoba	Ontario	Total	2002 Total
Travel Centres	9	8	5	2	13	37	37
Full Serve	15	18	3	8	2	46	50
Full/Self Serve	12	23	5	6	2	48	51
Self Serve	20	11	1	1	2	35	35
Bulk Distributor	1	7	4	1	1	14	15
Card/Key Locks	1	4	—	—	2	7	6
	58	71	18	18	22	187	194
Leased							
Travel Centre	1	—	—	—	—	1	1
Full Serve	5	12	6	7	—	30	32
Full/Self Serve	13	23	4	4	—	44	47
Self Serve	29	17	—	1	—	47	47
Bulk Distributor	3	—	—	—	—	3	3
Card/Key Locks	3	1	—	3	1	8	8
	54	53	10	15	1	133	138
Independent Retailers							
Travel Centre	1	1	—	—	4	6	4
Full Serve	24	26	10	16	8	84	89
Full/Self Serve	28	5	5	1	1	40	40
Self Serve	29	52	3	3	2	89	94
Bulk Distributor	2	4	1	—	—	7	7
Card/Key Locks	1	1	—	—	2	4	3
	85	89	19	20	17	230	237
Total							
Travel Centres	11	9	5	2	17	44	42
Full Serve	44	56	19	31	10	160	171
Full/Self Serve	53	51	14	11	3	132	138
Self Serve	78	80	4	5	4	171	176
Bulk Distributor	6	11	5	1	1	24	25
Card/Key Locks	5	6	—	3	5	19	17
	197	213	47	53	40	550	569
Cardlocks (1)	22	17	5	6	22	72	60
Convenience Stores (1)	186	196	42	49	34	507	524
Restaurants (2)	9	11	5	2	14	41	42

Notes:

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

(2) At December 31, 2003 and 2002, two Husky House restaurants in Alberta were 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 northwestern 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,		
	2003	2002	2001
		(mbbls/day)	
Gasoline	28.5	26.3	25.4
Diesel fuel	22.1	20.7	21.1
Liquefied petroleum gas	1.2	1.3	1.3
	51.8	48.3	47.8

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 trading opportunities to further enhance its existing refining capacity. Husky is currently assessing plans to upgrade the refinery to meet Federal regulations governing sulphur content in fuel.

Other Supply Arrangements. In addition to the refined petroleum products supplied by the Prince George refinery, Husky has established processing arrangements with major refiners. Processing arrangements allow Husky to participate in industry refining margins. Primarily Husky crude oil production and some third party purchased crude oil is delivered to major refiners, who process the crude oil into refined products, which are then marketed by Husky through its retail networks and to its wholesale customers. During 2003, these refiners processed an average of approximately 36.2 mbbls/day of crude oil for Husky, yielding approximately 32.7 mbbls/day of refined petroleum products. During 2003, Husky also purchased approximately 7.8 mbbls/day of refined petroleum products from refiners and acquired approximately 6.6 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 nine million litres per year of fuel ethanol and one million litres per year of industrial alcohol. Ethanol is produced primarily from wheat and other grains. It is an oxygenate, 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 planning to expand its ethanol production to meet provincial government mandates and internal demands. Ethanol-blended gasoline is now available at all Husky and Mohawk retail outlets. Husky also supplies E85 (85% ethanol content blended gasoline) to some Federal Government fleet vehicles across Western Canada.

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 2003, 45 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 an independent terminal 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,		
	2003	2002	2001
		(mbbls/day)	
Asphalt	12.9	12.7	12.6
Residual and other	9.1	8.1	8.8
	22.0	20.8	21.4

Refinery throughput averaged 25.7 mbbls/day of blended heavy crude oil feedstock during 2003. 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:

	December 31,	
	2003	2002
Upstream	1,753	1,560
Midstream	326	344
Refined Products	349	329
Corporate and business support	471	520
	2,899	2,753

Selected Consolidated Financial Information

	Years Ended December 31,		
	2003	2002	2001
	($ millions except per share amounts)		
Statement of earnings data			
Sales and operating revenue	7,658	6,384	6,596
Cash from operating activities	2,572	1,892	1,930
Net earnings	1,321	804	654
Per share — basic	3.23	1.88	1.49
Per share — diluted	3.22	1.88	1.48
Balance sheet data			
Total assets	11,782	10,575	9,370
Shareholders' equity	5,889	5,127	4,486
Total long-term debt	1,439	1,964	1,948

DIVIDENDS

The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31:

	2003	2002	2001
Cash Dividends Declared per Common Share	$1.38	$0.36	$0.36

Dividend Policy and Restrictions

The Board of Directors of Husky have established a dividend policy that pays quarterly dividends. From August 2000 to July 2003, Husky has paid a quarterly dividend of $0.09 ($0.36 annually) per common share. This policy was reviewed by the Board in July 2003 and the quarterly dividend was increased to $0.10 ($0.40 annually) per common share. The Board, also declared a special cash dividend of $1.00 per common share in July, 2003. The special dividend was paid on October 1, 2003. Husky's dividend policy will continue to be reviewed and 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, which will consider earnings, capital requirements and financial condition of Husky, the satisfaction of the applicable solvency test in Husky's governing corporate statute, the *Business Corporations Act*, (Alberta), and other relevant factors.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Husky is authorized to issue an unlimited number of common shares. Holders of common shares are entitled to one vote per share at meetings of shareholders of Husky, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of Husky upon its dissolution or winding up, subject to any rights having priority over the common shares.

Preferred Shares

Husky is authorized to issue an unlimited number of preferred shares. Holders of preferred shares shall not be entitled to vote at meetings of Husky, are entitled to receive such dividends as and when declared by the Board of Directors in priority to common shares and shall be entitled to receive pro-rata in priority to holders of common shares the remaining property and assets of Husky upon its dissolution or winding up. There are no preferred shares currently outstanding.

Credit Ratings

Disclosure with respect to the credit ratings Husky has received for its senior unsecured debt, Capital Securities and 8.45% senior secured bonds is set forth in Husky's 2003 Management's Discussion and Analysis 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''.

The following table discloses the trading price range and volume of Husky's common shares traded on the Toronto Stock Exchange during Husky's financial year ended December 31, 2003:

	High	Low	Volume (000's)
January	17.15	16.03	5,800
February	17.49	16.07	5,547
March	17.35	16.36	7,024
April	17.20	16.15	6,819
May	16.81	16.31	8,397
June	18.14	16.60	9,641
July	19.58	17.35	10,656
August	20.95	18.43	13,795
September	20.85	19.30	11,001
October	23.30	20.40	9,822
November	22.75	21.48	5,821
December	23.95	21.35	6,528

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

Husky's Management's Discussion and Analysis for the fiscal years ended December 31, 2003 and December 31, 2002 is incorporated herein by reference and is available on SEDAR at *www.sedar.com*.

Comparability of Annual Data

Changes in accounting policies, major acquisitions and divestitures, or major changes in the nature of Husky's business that affect the comparability of the annual data in this Annual Information Form, are listed below:

(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 acquisition of Marathon Canada Limited; and

(iii) 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(j) and (k), 7 and 16 respectively, to the Consolidated Financial Statements of Husky for the year ended December 31, 2003 and are incorporated herein by reference. The Consolidated Financial Statements are available on SEDAR at *www.sedar.com*.

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	Director Since	Principal Occupation During Past 5 Years
Li, Victor T.K. ..... Hong Kong	Co-Chairman and Director	August 25, 2000	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.
Fok, Canning K.N. ..... Hong Kong	Co-Chairman and Director	August 25, 2000	Group Managing Director of Hutchison Whampoa Limited since 1993 and Executive Director since 1984. Mr. Fok has been the Chairman of Hutchison Harbour Ring Limited (an investment holding company) since 2002, Hutchison Telecommunications (Australia) Limited (a telecommunications company) since 1999, Partner Communications Company Ltd. (a telecommunications company) since 1998 and Vanda Systems & Communications Holdings Limited (an investment holdings company) since 2003. Mr. Fok is also 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.
Fullerton, R. Donald ..... Toronto, Ontario Canada	Director	May 1, 2003	Corporate Director. From 1992 until 1999 he chaired the Executive Committee of CIBC's Board and retired as a director in February 2004. He currently serves on the Boards of George Weston Limited (a holding company) since 1991, Asia Satellite Telecommunications Holdings Ltd. since 1996 and Partner Communications Ltd. since 2003.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
Glynn, Martin J.G. ..... New York, New York U.S.A.	Director	August 25, 2000	President and Chief Executive Officer of HSBC Bank USA since 2003 and a director since 2000. Mr. Glynn has been a director of HSBC Bank Canada since 1999 and was President and Chief Executive Officer from 1999 to 2003. From 1982 Mr. Glynn held various senior executive positions with HSBC Bank Canada (formerly Hongkong Bank of Canada). Mr. Glynn has been a Director of HSBC North America Inc. since 2002, and a Director of HSBC USA Inc. Mr. Glynn is also a director of Wells Fargo HSBC Trade Bank N.A.
Hui, Terence C.Y. ..... Vancouver, British Columbia Canada	Director	August 25, 2000	Director, President & Chief Executive Officer, Concord Pacific Group Inc. (a real estate development company) since 1997, Director and President of Adex Securities Inc. (a financial services company) since 1992 and Director and Chairman of Maximizer Software Inc. (formerly Multiactive Software Inc.) and Multiactive Technologies Inc. (computer software companies) since 1995. Mr. Hui was President and Chief Executive Officer of Pacific Place Developments Corp. (a real estate development company) from 1992 to 2001.
Kinney, Brent D. ..... Dubai, United Arab Emirates	Director	August 25, 2000	Independent businessman. Mr. Kinney is a director of Dragon Oil plc in the United Arab Emirates and Aurado Energy Inc. since 2003.
Kluge, Holger..... Toronto, Ontario Canada	Director	August 25, 2000	Corporate Director. Mr. Kluge was President, Personal and Commercial Bank, CIBC 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, Loring Ward International Limited (a financial planning company) since 2004 and TOM.COM LIMITED. Mr. Kluge holds a Bachelor of Commerce degree and a Master's degree in Business Administration.
Koh, Poh Chan ..... Hong Kong	Director	August 25, 2000	Finance Director, Harbour Plaza Hotel Management (International) Ltd.
Kwok, Eva L. ..... Vancouver, British Columbia Canada	Director	August 25, 2000	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 Bank of Montreal Group of Companies and since 2002 of CK Life Sciences Int'l., (Holdings) Inc.
Kwok, Stanley T.L. ..... Vancouver, British Columbia Canada	Director	August 25, 2000	President, Stanley Kwok Consultants (an architecture, planning 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 Canada	President & Chief Executive Officer and Director	August 25, 2000	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.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
Shaw, Wayne E. ..... Toronto, Ontario Canada	Director	August 25, 2000	Senior Partner, Stikeman Elliott LLP, Barristers and Solicitors
Shurniak, William ..... Australia	Deputy Chairman and Director	August 25, 2000	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 been a director of Hutchison Whampoa Limited since 1984, Envestra Limited (a natural gas distributor) since 2000 and CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2003. Mr. Shurniak was a director and Deputy Chairman of Asia Satellite Telecommunications Holdings Ltd. 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	August 25, 2000	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.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
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 & Chief Financial Officer of Husky Oil Limited since 1998.
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.

The Board of Directors has an Audit Committee (as required by the *Business Corporations Act* (Alberta)) currently consisting of M.J.G. Glynn (Chair), T. C.Y. Hui, R.D. Fullerton and W.E. Shaw, a Compensation Committee currently consisting of C.K.N. Fok (Chair), H. Kluge, E.L. Kwok and F.J. Sixt, a Health, Safety and Environment Committee currently consisting of H. Kluge, (Chair), B. D. Kinney, and S.T.L. Kwok and a Corporate Governance Committee currently consisting of H. Kluge (Chair), E.L. Kwok and W.E. Shaw. Husky does not have an Executive Committee.

As at February 17, 2004, the directors and officers of Husky, as a group, owned beneficially, directly or indirectly, or exercised control or direction over 386,011 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 Company 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, other than Eva Kwok who was a director of Air Canada in 2003 at the time it became subject to creditor protection under the *Companies' Creditors Arrangement Act (Canada)*.

Penalties or Sanctions

None of the persons who are directors, officers or promoters of the Company 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.

LEGAL PROCEEDINGS

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 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 or other matters or amount which may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own directly or indirectly, or exercise control or direction over, more than 10 percent of Husky's common shares, or their associates and affiliates, had any material interest, direct or indirect, in any transaction with the Company within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Company except as follows.

The Company leases its head office space located in Western Canadian Place in Calgary, Alberta from Western Canadian Place Ltd., which is indirectly controlled by the Company's principal shareholders. The Company's President & Chief Executive Officer and Vice President & Chief Financial Officer are also a directors and officers of Western Canadian Place Ltd. The Vice President, Corporate Administration of the Company's subsidiary, Husky Oil Operations Limited, is also a director and officer of Western Canadian Place Ltd. The Company entered into a lease for an eight year term effective September 1, 2000, with Western Canadian Place Ltd. on commercial terms consistent with those for leases of comparable space in Class A office buildings in Calgary.

The Company has also entered into a management agreement with Western Canadian Place Ltd. for general management of the building. The Company was paid fees of $36,663 in 2003 (down from $238,017 in 2002 due to credits in favour of Western Canadian Place Ltd.) for providing such management services.

TRANSFER AGENTS AND REGISTRARS

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. The registers for transfers of the Company's common shares are maintained by Computershare Trust Company of Canada at its principal offices in the cities of Calgary and Toronto. Queries should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal shareholders of Husky's common shares and options to purchase common shares and interests of insiders in material transactions is contained in Husky's Management Information Circular dated March 18, 2004 (the ''Information Circular''), prepared in connection with the annual meeting of shareholders to be held on April 22, 2004.

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, 2003, contained in Husky's 2003 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 preliminary short form prospectus or a 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.

Additional information relating to Husky Energy Inc. is available on SEDAR at *www.sedar.com.*

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Information Form are forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. 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 in this Annual Information Form. and available on SEDAR at *www.sedar.com.*

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 2

CONSOLIDATED FINANCIAL STATEMENTS AND AUDITORS' REPORT TO SHAREHOLDERS

For the Year Ended December 31, 2003

Exhibit 2

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 LLP, the independent auditors, in accordance with generally accepted auditing standards on behalf of the shareholders. KPMG LLP 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 2, 2004

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2003, 2002 and 2001 and the consolidated statements of earnings, retained earnings, and cash flows for each of the years in the three-year period ended December 31, 2003. 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, 2003, 2002 and 2001 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

KPMG LLP
Chartered Accountants

Calgary, Alberta, Canada
February 2, 2004

CONSOLIDATED BALANCE SHEETS

	As at December 31		
	2003	2002	2001
	(millions of dollars)		
Assets			
Current assets			
Cash and cash equivalents	$ 3	$ 306	$ —
Accounts receivable *(note 4)*	618	572	376
Inventories *(note 5)*	211	243	226
Prepaid expenses	33	23	24
	865	1,144	626
Property, plant and equipment, net *(notes 1, 6)* (full cost accounting)	10,685	9,347	8,715
Goodwill *(note 7)*	120	—	—
Other assets *(note 11)*	112	84	29
	$11,782	$10,575	$9,370
Liabilities and Shareholders' Equity			
Current liabilities			
Bank operating loans *(note 9)*	$ 71	$ —	$ 100
Accounts payable and accrued liabilities *(note 10)*	1,126	794	805
Long-term debt due within one year *(note 11)*	259	421	144
	1,456	1,215	1,049
Long-term debt *(note 11)*	1,439	1,964	1,948
Other long-term liabilities *(note 12)*	390	266	228
Future income taxes *(note 13)*	2,608	2,003	1,659
Commitments and contingencies *(note 14)*			
Shareholders' equity			
Capital securities and accrued return *(note 15)*	298	364	367
Common shares *(note 16)*	3,457	3,406	3,397
Retained earnings	2,134	1,357	722
	5,889	5,127	4,486
	$11,782	$10,575	$9,370

On behalf of the Board:

John C. S. Lau
Director

Martin J. G. Glynn
Director

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

CONSOLIDATED STATEMENTS OF EARNINGS

	Year ended December 31		
	2003	2002	2001
	(millions of dollars, except per share amounts)		
Sales and operating revenues, net of royalties	$7,658	$6,384	$6,596
Costs and expenses			
Cost of sales and operating expenses	4,825	4,009	4,425
Selling and administration expenses	119	94	88
Depletion, depreciation and amortization *(notes 1, 6)*	1,058	939	807
Interest — net *(note 11)*	73	104	101
Foreign exchange *(note 11)*	(215)	13	94
Other — net	3	1	7
	5,863	5,160	5,522
Earnings before income taxes	1,795	1,224	1,074
Income taxes *(note 13)*			
Current	147	66	20
Future	327	354	400
	474	420	420
Net earnings	$1,321	$ 804	$ 654
Earnings per share *(note 16)*			
Basic	$ 3.23	$ 1.88	$ 1.49
Diluted	$ 3.22	$ 1.88	$ 1.48

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year ended December 31		
	2003	2002	2001
	(millions of dollars)		
Beginning of year	$1,357	$ 722	$ 253
Net earnings	1,321	804	654
Dividends on common shares *(note 16)*	(580)	(151)	(150)
Return on capital securities *(note 15)*	38	(29)	(53)
Related future income taxes *(note 13)*	(2)	11	18
End of year	$2,134	$1,357	$ 722

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31		
	2003	2002	2001
	(millions of dollars)		
Operating activities			
Net earnings	$ 1,321	$ 804	$ 654
Items not affecting cash			
Depletion, depreciation and amortization	1,058	939	807
Future income taxes	327	354	400
Foreign exchange *(note 11)*	(242)	—	82
Other	(5)	(1)	3
Cash flow from operations	2,459	2,096	1,946
Change in non-cash working capital *(note 8)*	113	(204)	(16)
Cash flow — operating activities	2,572	1,892	1,930
Financing activities			
Bank operating loans financing — net	71	(100)	66
Long-term debt issue	598	972	—
Long-term debt repayment	(971)	(678)	(356)
Settlement of cross currency swap	(32)	—	—
Return on capital securities payment	(29)	(31)	(30)
Debt issue costs	—	(9)	—
Deferred credits	—	—	(4)
Proceeds from exercise of stock options	51	9	9
Proceeds from interest swaps monetization	44	—	—
Dividends on common shares	(580)	(151)	(150)
Change in non-cash working capital *(note 8)*	48	(9)	42
Cash flow — financing activities	(800)	3	(423)
Available for investing	1,772	1,895	1,507
Investing activities			
Capital expenditures	(1,905)	(1,692)	(1,473)
Corporate acquisitions	(809)	(3)	(125)
Asset sales	511	93	67
Other	5	(20)	6
Change in non-cash working capital *(note 8)*	123	33	18
Cash flow — investing activities	(2,075)	(1,589)	(1,507)
Increase (decrease) in cash and cash equivalents	(303)	306	—
Cash and cash equivalents at beginning of year	306	—	—
Cash and cash equivalents at end of year	$ 3	$ 306	$ —

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

Note 1 Segmented Financial Information

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
Year ended December 31									
Sales and operating revenues, net of royalties	$ 3,186	$ 2,665	$ 2,165	$1,013	$909	$886	$4,946	$4,230	$4,380
Costs and expenses									
Operating, cost of sales, selling and general	855	729	648	901	811	638	4,747	4,038	4,193
Depletion, depreciation and amortization	958	851	728	20	18	17	21	20	17
Interest — net	—	—	—	—	—	—	—	—	—
Foreign exchange	—	—	—	—	—	—	—	—	—
	1,813	1,580	1,376	921	829	655	4,768	4,058	4,210
Earnings (loss) before income taxes	1,373	1,085	789	92	80	231	178	172	170
Current income taxes	95	55	17	1	1	1	27	6	1
Future income taxes	230	342	290	20	25	72	37	59	71
Net earnings (loss)	$ 1,048	$ 688	$ 482	$ 71	$ 54	$158	$ 114	$ 107	$ 98
Capital employed — As at December 31	$ 6,652	$ 6,040	$ 5,715	$ 456	$319	$320	$ 350	$ 431	$ 395
Property, plant and equipment — As at December 31									
Cost									
Canada	$13,601	$11,525	$10,353	$1,022	$998	$958	$ 615	$ 591	$ 575
International	496	469	394	—	—	—	—	—	—
	$14,097	$11,994	$10,747	$1,022	$998	$958	$ 615	$ 591	$ 575
Accumulated depletion, depreciation and amortization									
Canada	$ 4,633	$ 3,894	$ 3,272	$ 391	$372	$354	$ 203	$ 184	$ 165
International	250	185	147	—	—	—	—	—	—
	$ 4,883	$ 4,079	$ 3,419	$ 391	$372	$354	$ 203	$ 184	$ 165
Net									
Canada	$ 8,968	$ 7,631	$ 7,081	$ 631	$626	$604	$ 412	$ 407	$ 410
International	246	284	247	—	—	—	—	—	—
	$ 9,214	$ 7,915	$ 7,328	$ 631	$626	$604	$ 412	$ 407	$ 410
Capital expenditures — Year ended December 31 (2)	$ 1,781	$ 1,567	$ 1,317	$ 25	$ 41	$ 47	$ 18	$ 17	$ 58
Total assets — As at December 31 (3)									
Canada	$ 9,547	$ 7,883	$ 7,160	$ 649	$658	$644	$ 701	$ 850	$ 862
International	259	337	247	—	—	—	—	—	—
	$ 9,806	$ 8,220	$ 7,407	$ 649	$658	$644	$ 701	$ 850	$ 862

(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) Includes site restoration expenditures. See note 12, Other Long-term Liabilities.

(3) 2003 includes goodwill on Marathon Canada Limited acquisition related to Upstream.

	Refined Products			Corporate and Eliminations (1)			Total		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
Year ended December 31									
Sales and operating revenues, net of royalties	$1,502	$1,310	$1,349	$(2,989)	$(2,730)	$(2,184)	$ 7,658	$ 6,384	$ 6,596
Costs and expenses									
Operating, cost of sales, selling and general	1,422	1,222	1,206	(2,978)	(2,696)	(2,165)	4,947	4,104	4,520
Depletion, depreciation and amortization	34	34	31	25	16	14	1,058	939	807
Interest — net	—	—	—	73	104	101	73	104	101
Foreign exchange	—	—	—	(215)	13	94	(215)	13	94
	1,456	1,256	1,237	(3,095)	(2,563)	(1,956)	5,863	5,160	5,522
Earnings (loss) before income taxes	46	54	112	106	(167)	(228)	1,795	1,224	1,074
Current income taxes	9	4	1	15	—	—	147	66	20
Future income taxes	9	18	48	31	(90)	(81)	327	354	400
Net earnings (loss)	$ 28	$ 32	$ 63	$ 60	$ (77)	$ (147)	$ 1,321	$ 804	$ 654
Capital employed — As at December 31	$ 320	$ 338	$ 329	$ (120)	$ 384	$ (81)	$ 7,658	$ 7,512	$ 6,678
Property, plant and equipment — As at December 31									
Cost									
Canada	$ 757	$ 702	$ 655	$ 188	$ 165	$ 143	$16,183	$13,981	$12,684
International	—	—	—	—	—	—	496	469	394
	$ 757	$ 702	$ 655	$ 188	$ 165	$ 143	$16,679	$14,450	$13,078
Accumulated depletion, depreciation and amortization									
Canada	$ 391	$ 360	$ 330	$ 126	$ 108	$ 95	$ 5,744	$ 4,918	$ 4,216
International	—	—	—	—	—	—	250	185	147
	$ 391	$ 360	$ 330	$ 126	$ 108	$ 95	$ 5,994	$ 5,103	$ 4,363
Net									
Canada	$ 366	$ 342	$ 325	$ 62	$ 57	$ 48	$10,439	$ 9,063	$ 8,468
International	—	—	—	—	—	—	246	284	247
	$ 366	$ 342	$ 325	$ 62	$ 57	$ 48	$10,685	$ 9,347	$ 8,715
Capital expenditures — Year ended December 31 (2)	$ 58	$ 44	$ 29	$ 23	$ 23	$ 22	$ 1,905	$ 1,692	$ 1,473
Total assets — As at December 31 (3)									
Canada	$ 525	$ 534	$ 428	$ 101	$ 313	$ 29	$11,523	$10,238	$ 9,123
International	—	—	—	—	—	—	259	337	247
	$ 525	$ 534	$ 428	$ 101	$ 313	$ 29	$11,782	$10,575	$ 9,370

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, Canada.

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 other 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

a) Principles of Consolidation and the Preparation of Financial Statements

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 20, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with Canadian 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.

Substantially all of the Company's upstream activities are conducted jointly with third parties and accordingly the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flow from these activities.

b) Cash and Cash Equivalents

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

c) 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.

d) 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 activity, 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 gross 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. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20 percent or more.

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 the related future income tax liability and site restoration liability, 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, administration expenses, financing costs and income taxes. Any amounts in excess of these limits are charged to earnings.

In September 2003, the Accounting Standards Board (''AcSB'') of the Canadian Institute of Chartered Accountants (''CICA'') issued Accounting Guideline 16, ''Oil and Gas Accounting — Full Cost'' (''AcG-16''), which replaces Accounting Guideline 5, ''Full Cost Accounting in the Oil and Gas Industry'' (''AcG-5''). AcG-16 will be effective January 1, 2004. AcG-16 modifies the ceiling test in AcG-5 to be consistent with CICA section 3063, ''Impairment of Long-lived Assets'', which requires the impairment test to be performed by comparing the carrying amount of a cost centre to its fair value. For full cost oil and gas companies an impairment loss is to be recognized when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not considered recoverable if the carrying amount exceeds the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. Fair value is estimated using the expected present value approach which incorporates risks and uncertainties in the expected future cash flows which are discounted using a risk free rate. AcG-16 is consistent with CICA section 3475, ''Disposal of Long-lived Assets and Discontinued Operations''. For full cost oil and gas companies, discontinued operations presentation is only used when a cost centre has been disposed of.

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 which range from five to 20 years. 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, 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.

In March 2003, the AcSB issued CICA section 3110, ''Asset Retirement Obligations'', that addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the related asset retirement costs. The new recommendations will be effective January 1, 2004 and are substantially similar to the U.S. Financial Accounting Standards Board (''FASB'') Statement No. 143, ''Accounting for Asset Retirement Obligations'' (''FAS 143''). Note 20 presents the recognition, measurement and disclosure required by FAS 143 in the financial statements.

e) Impairment or Disposal of Long-lived Assets

In December 2002, the AcSB issued CICA section 3063, ''Impairment of Long-lived Assets'', and section 3475, ''Disposal of Long-lived Assets and Discontinued Operations'', that address the accounting and reporting for the impairment and disposal of long-lived assets and are substantially similar to FASB Statement No. 144, ''Accounting for the Impairment and Disposal of Long-lived Assets''. Section 3063 will be effective January 1, 2004. Section 3475 was in effect for 2003. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. 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, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) 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.

f) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on an annual basis unless three conditions are met: i) the assets and liabilities that make up the reporting unit have not changed significantly since the most recent fair value determination; ii) the most recent fair value determination resulted in an amount that exceeded the carrying amount of the reporting unit by a substantial margin; and, iii) based on an analysis of events that have occurred and circumstances that have changed since the most recent fair value determination, the likelihood that a current fair value determination would be less than the current carrying amount of the reporting unit is remote. The two-step impairment test begins with comparing the fair value of the reporting unit with its carrying amount. If any potential impairment is indicated, then it is quantified by comparing the carrying value of goodwill to its fair value, based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings. Refer to note 7, Acquisition of Marathon Canada.

g) Derivative Financial Instruments

Derivative financial instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

When applicable, the Company formally documents all relationships between hedged items and hedging items, the risk management objectives and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company may enter into commodity price contracts to hedge anticipated sales of oil and natural gas production to manage its exposure to price fluctuations. The Company's production is expected to be sufficient to deliver all required volumes. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers in order to retain market prices while meeting customer or supplier pricing requirements. The Company's production is expected to be sufficient to deliver all required volumes. Gains and losses from these contracts are recognized in midstream revenues or cost of sales as the related sales or purchases occur.

The Company may enter into interest rate swap agreements to manage its fixed and floating interest rate mix on long-term debt. These swaps are designated as hedges of the underlying debt. These agreements require the periodic exchange of payments without the exchange of the notional principal amount upon which the payments are based and are recorded as an adjustment to the interest expense on the hedged debt instrument. The related amount payable or receivable from the counterparties is recorded as an adjustment to accrued interest.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The forward premium or discount on the forward foreign exchange option contract is amortized as an adjustment to interest expense over the term of the contract.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

Realized and unrealized gains or losses associated with derivative financial instruments which have been terminated or cease to be effective prior to maturity are deferred under current or non-current assets or liabilities on the balance sheet and recognized into income in the period in which the underlying hedged transaction is recognized. In the event that a designated hedged item is sold, extinguishes or matures prior to the termination of the related derivative financial instrument, any realized or unrealized gain or loss is recognized into earnings.

In December 2001, the AcSB issued Accounting Guideline 13, ''Hedging Relationships'', that establishes standards for the documentation and effectiveness of hedging activities that are substantially similar to the corresponding documentation requirements in FASB Statement No. 133 ''Accounting for Derivative Instruments and Hedging Activities'' (''FAS 133''). The new recommendations will be effective January 1, 2004. Note 20 discloses the impact of FAS 133 on the financial statements for 2003.

h) Employee Future Benefits

The Company provides a defined contribution pension plan and a post-retirement health and dental care plan to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. The cost of the pension benefits earned by employees in the defined contribution pension plan is paid and expensed when incurred. The cost of the benefits earned by employees in the post-retirement health and dental care plan and defined benefit pension plan is charged to earnings as services are rendered using the projected benefit method prorated on service. The cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The plan assets are valued at fair value for the purposes of calculating the expected return on plan assets.

Adjustments arising out of plan amendments, changes in assumptions and experience gains and losses are normally amortized over the expected remaining average service life of the employee group.

i) 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.

j) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars at the monthly average exchange rates for revenue and expenses, except for depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets and liabilities are translated at current exchange rates and non-monetary assets and liabilities 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.

k) Stock-based Compensation

In accordance with the Company's stock option plan, common share options may be 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 options is equal to the market value of the common shares when the options are granted. In accordance with CICA section 3870, ''Stock-based Compensation and Other Stock-based Payments'', note 16 discloses the impact on the financial statements for options granted after January 1, 2002. The recommendations are substantially similar to those in FASB Statement No. 123, ''Accounting for Stock-based Compensation'' (''FAS 123''). Note 20 presents the disclosures required by FAS 123 in the financial statements.

In September 2003, the AcSB amended the recommendations on stock-based compensation. The new recommendations will be effective January 1, 2004 and will require that all stock-based compensation be measured and recognized based on the fair value of the instruments and will result in an expense that is recognized in the financial statements. The Company intends to adopt the changes retroactively in 2004 without restatement of prior periods. Retained earnings for 2004 will be decreased by $44 million with an increase to contributed surplus of $21 million and an increase to share capital of $23 million.

l) 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.

m) Reclassification

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

Note 4 Accounts Receivable

	2003	2002	2001
Trade receivables	$568	$530	$379
Investment tax credit	48	45	—
Allowance for doubtful accounts	(12)	(11)	(8)
Other	14	8	5
	$618	$572	$376

Sale of Accounts Receivable

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

In 2002 and 2001, the Company had an agreement to sell up to $200 million of net trade receivables on a continual basis. The agreement called for purchase discounts which were based on Canadian commercial paper rates. The average effective rate for 2002 and 2001 was approximately 2.8 percent and 4.7 percent, respectively.

Note 5 Inventories

	2003	2002	2001
Crude oil and refined petroleum products	$121	$166	$140
Natural gas	69	50	69
Materials, supplies and other	21	27	17
	$211	$243	$226

Note 6 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:

	2003	2002	2001
Canada	$1,814	$1,318	$1,226
International	54	37	235
	$1,868	$1,355	$1,461

Note 7 Acquisition of Marathon Canada

Effective October 1, 2003 the Company acquired all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. (''Marathon Canada'') for cash consideration of U.S. $611 million (Cdn. $831 million). The results of Marathon Canada are included in the consolidated financial statements of the Company from the date of acquisition.

The allocation of the aggregate purchase price based on the estimated fair values of Marathon Canada's net assets acquired at October 1, 2003 was as follows:

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

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

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

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

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

a) Change in non-cash working capital was as follows:

	2003	2002	2001
Decrease (increase) in non-cash working capital			
Accounts receivable	$ (7)	$(153)	$361
Inventories	31	(17)	(40)
Prepaid expenses	(10)	1	3
Accounts payable and accrued liabilities	270	(11)	(280)
Change in non-cash working capital	284	(180)	44
Relating to:			
Financing activities	48	(9)	42
Investing activities	123	33	18
Operating activities	$113	$(204)	$ (16)

b) Other cash flow information:

	2003	2002	2001
Cash taxes paid	$ 69	$ 20	$ 13
Cash interest paid	$134	$139	$145

Note 9 Bank Operating Loans

At December 31, 2003 the Company had short-term borrowing lines of credit with banks totalling $195 million (2002 and 2001 — $195 million). As at December 31, 2003, $71 million (2002 — nil; 2001 — $100 million) had been used for bank operating loans and $18 million (2002 — $12 million; 2001 — $2 million) had been used for letters of credit. Interest payable is based on Bankers' Acceptance, money market, or prime rates. During 2003, the weighted average interest rate on short-term borrowings was approximately 3.7 percent (2002 — 2.9 percent; 2001 — 4.6 percent).

Note 10 Accounts Payable and Accrued Liabilities

	2003	2002	2001
Trade payables	$ 58	$ 87	$ 58
Accrued liabilities	794	562	547
Dividend payable	42	38	38
Current income taxes	117	51	7
Other	115	56	155
	$1,126	$794	$805

Note 11 Long-term Debt

		Cdn. $ Amount			U.S. $ Amount		
	Maturity	2003	2002	2001	2003	2002	2001
Long-term debt							
Revolving syndicated credit facility		$ —	$ —	$ 185	$ —	$ —	$116
6.25% notes	2012	517	632	—	400	400	—
6.875% notes		—	237	239	—	150	150
7.125% notes	2006	194	237	239	150	150	150
7.55% debentures	2016	258	316	318	200	200	200
8.45% senior secured bonds	2004-12	188	256	276	145	162	173
Private placement notes	2004-5	41	107	135	32	68	85
Medium-term notes	2004-9	500	600	700	—	—	—
Total long-term debt		1,698	2,385	2,092	$927	$1,130	$874
Amount due within one year		(259)	(421)	(144)			
		$1,439	$1,964	$1,948			

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

	2003	2002	2001
Long-term debt	$129	$128	$148
Short-term debt	2	3	5
	131	131	153
Amount capitalized	(52)	(26)	(51)
	79	105	102
Interest income	(6)	(1)	(1)
	$ 73	$104	$101

Foreign exchange for the years ended December 31 was as follows:

	2003	2002	2001
(Gain) loss on translation of U.S. dollar denominated long-term debt	$ (315)	$—	$82
Cross currency swaps	73	—	—
Other losses	27	13	12
	$ (215)	$13	$94

As at December 31, 2003, other assets included $19 million (2002 — $23 million; 2001 — $17 million) of deferred debt issue costs.

The revolving syndicated credit facility allows the Company to borrow up to $830 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 three-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 Company's $100 million credit facility has substantially the same terms as the syndicated credit facility.

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 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. These securities mature in 2006 and 2016, respectively. The 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 Terra Nova oil field and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the Terra Nova oil field. There is also a charge created by the partnership on its interest in the assets of the Terra Nova 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 were issued under two separate note agreements dated January 31, 2001 and have a weighted average interest rate of 6.86 percent. 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 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 D	200	6.30%	June 2004
Series E	200	6.95%	July 2009
	$500		

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: 2004 — $259 million; 2005 — $60 million; 2006 — $226 million; 2007 — $126 million; and, 2008 — $20 million.

Note 12 Other Long-term Liabilities

	2003	2002	2001
Site restoration	$303	$248	$211
Cross currency swaps	41	—	—
Interest rate swaps	26	—	—
Employee future benefits	20	17	16
Other	—	1	1
	$390	$266	$228

The Company has estimated future removal and site restoration costs of $851 million at December 31, 2003 (2002 — $703 million; 2001 — $653 million). During 2003 actual removal and site restoration expenditures amounted to $35 million (2002 — $17 million; 2001 — $18 million) and were included in capital expenditures.

Note 13 Income Taxes

The combined provision for income taxes in the Consolidated Statements of Earnings and Retained Earnings 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:

	2003	2002	2001
Earnings before income taxes			
Canadian	$1,572	$1,070	$1,067
Foreign jurisdictions	223	154	7
	1,795	1,224	1,074
Statutory income tax rate *(percent)*	40.2	41.6	43.7
Expected income tax	722	509	469
Effect on income tax of:			
Change in statutory tax rate	(161)	(31)	(52)
Return on capital securities	2	(11)	(18)
Royalties, lease rentals and mineral taxes payable to the crown	175	159	184
Resource allowance on Canadian production income	(183)	(212)	(219)
Non-deductible capital taxes	22	18	20
Gains and losses on foreign exchange	(45)	—	20
Rate benefit on timing of partnership earnings	(23)	—	—
Foreign jurisdictions	(16)	(13)	—
Other — net	(17)	(10)	(2)
	$ 476	$ 409	$ 402
Charged (credited) to:			
Income tax expense	$ 474	$ 420	$ 420
Retained earnings	2	(11)	(18)
	$ 476	$ 409	$ 402

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

	2003	2002	2001
Future tax liabilities			
Property, plant and equipment	$2,261	$2,014	$1,882
Foreign exchange gains taxable on realization	32	—	—
Timing of partnership items	504	185	—
Other temporary differences	2	30	7
	2,799	2,229	1,889
Future tax assets			
Loss carryforwards	2	7	28
Foreign exchange losses deductible on realization	—	28	26
Site restoration and other deferred credits	112	105	93
Provincial royalty rebates	52	48	46
Other temporary differences	25	38	37
	191	226	230
	$2,608	$2,003	$1,659

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 requires payments to them when the average differential between heavy crude oil feedstock and synthetic crude oil exceeds $6.50 per barrel. The calculation is based on

a two-year rolling average of the differential. During 2003, the Company capitalized $10 million (2002 — $23 million; 2001 — $32 million) of payments under this arrangement.

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

At December 31, 2003, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2004	2005	2006	2007	2008	After 2008	Total
Operating leases	$ 50	$ 68	$ 76	$ 75	$ 70	$ 175	$ 514
Firm transportation agreements	236	219	224	199	170	740	1,788
Unconditional purchase obligations	332	234	210	118	6	15	915
Exploration lease agreements	47	47	73	51	46	233	497
Engineering and construction commitments	391	206	—	—	—	—	597
	$1,056	$774	$583	$443	$292	$1,163	$4,311

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 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 amount, net of income taxes, is classified as a distribution of equity. Return on capital securities comprises the return and foreign exchange on the capital securities.

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

	2003	2002	2001
Capital securities — U.S. $225	$291	$355	$358
Unamortized costs of issue	(3)	(3)	(3)
Accrued return	10	12	12
	$298	$364	$367

In November 2003 the AcSB revised recommendations in CICA section 3860, ''Financial Instruments — Disclosure and Presentation'', on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations will be effective January 1, 2005 and will result in the Company's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs would be classified outside of shareholders' equity. The return on the capital securities would be a charge to earnings. The revision will be applied retroactively in 2005.

Note 16 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, none outstanding.

Changes to issued share capital were as follows:

Common Shares

	Number of Shares	Amount
January 1, 2001	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
Options and warrants exercised	4,302,141	51
December 31, 2003	422,175,742	$3,457

Stock Options

At December 31, 2003, 25.7 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. A downward adjustment of $0.82 to the exercise price of all outstanding stock options effective September 3, 2003 was made pursuant to the terms of the stock option plan under which the options were issued as a result of the special $1.00 per share dividend that was declared on July 23, 2003. 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.

The following options to purchase common shares have been awarded to directors, officers and certain other employees:

	Number of Shares	Weighted Average Exercise Prices	Weighted Average Contractual Life	Options Exercisable
	(thousands)		(years)	(thousands)
January 1, 2001	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
Granted	591	$19.17	5	
Exercised	(3,789)	$13.45	2	
Forfeited	(125)	$14.71	2	
December 31, 2003	4,597	$13.88	2	3,564

At December 31, 2003, the options outstanding had exercise prices ranging from $10.34 to $22.01.

Warrants

In 2000, the Company granted 1.4 million Renaissance Energy Ltd. (''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. During 2003, 276,500 warrants were exercised (2002 — 208,500; 2001 — 226,000). As at December 31, 2003, there were 295,820 common shares remaining which could potentially be issued as a result of the exercise of these warrants. The Renaissance replacement options had a weighted average contractual life of 0.6 years.

Stock-based Compensation

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

	2003	2002	2001
Weighted average fair market value per option	$4.00	$5.19	$5.70
Risk-free interest rate *(percent)*	3.9	3.6	3.5
Volatility *(percent)*	23	43	45
Expected life *(years)*	5	5	5
Expected annual dividend per share	$0.36	$0.36	$0.36

The fair values of all common share options granted prior to September 3, 2003 were revalued at the modification date using the Black-Scholes option-pricing model. The weighted average fair market value of outstanding stock options as at September 3, 2003 and the assumptions used in their determination are as noted below:

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

The Company follows the intrinsic value method of accounting for stock-based compensation for its stock option plan, under which compensation cost is not recognized. If the Company applied the fair value method, additional compensation cost of $3.9 million for all options granted would be recognized over the vesting period due to the modification of all options outstanding. For the year ended December 31, 2003, additional compensation cost of $3.6 million would be recognized.

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

	2003	2002	2001
Compensation cost — options granted after January 1, 2002(1)	$ 5	$ —	$ —
Compensation cost — all options granted(1)	$ 14	$ 13	$ 13
Net earnings available to common shareholders			
As reported	$1,357	$ 787	$ 620
Options granted after January 1, 2002	$1,352	$ 787	$ 620
All options granted	$1,343	$ 774	$ 607
Weighted average number of common shares outstanding *(millions)*			
Basic	419.5	417.4	416.1
Diluted	421.5	419.3	418.6
Basic earnings per share			
As reported	$ 3.23	$1.88	$1.49
Options granted after January 1, 2002	$ 3.22	$1.88	$1.49
All options granted	$ 3.20	$1.86	$1.46
Diluted earnings per share			
As reported	$ 3.22	$1.88	$1.48
Options granted after January 1, 2002	$ 3.21	$1.88	$1.48
All options granted	$ 3.18	$1.85	$1.45

(1) Includes options modified.

Effective January 1, 2004 the Company is required to measure stock-based compensation and recognize an expense in the financial statements. The Company will be adopting the change in 2004 on a retroactive basis without restatement of prior periods for all options granted. Retained earnings will be decreased by $44 million, which includes a cost of $4 million for the year ended December 31, 2000.

Earnings Per Share Amounts

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

Diluted earnings per common share includes the dilutive impact of options and warrants outstanding under the Company 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 per common share, as the Company has neither the obligation nor intention to settle amounts due through the issuance of shares.

During 2003 the Company declared dividends of $1.38 per common share (2002 and 2001 — $0.36 per common share), including a special dividend of $1.00 per common share.

Note 17 Employee Future 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 health and dental coverage to its retirees which is accrued over the expected average remaining service life of the employees.

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

	2003	2002	2001
		(percent)	
Discount rate	6.0	6.3	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 average health care cost trend used was eight percent, which is reduced by 0.50 percent until 2009. The average dental care cost trend used was four percent, which remains constant.

Defined Benefit Pension Plan

The status of the defined benefit pension plan at December 31 was as follows:

Benefit Obligation	2003	2002	2001
Benefit obligation, beginning of year	$108	$ 95	$ 93
Current service cost	2	2	1
Interest cost	7	7	6
Benefits paid	(6)	(6)	(5)
Actuarial losses	7	10	—
Benefit obligation, end of year	$118	$108	$ 95

Fair Value of Plan Assets	2003	2002	2001
Fair value of plan assets, beginning of year	$ 77	$ 85	$ 90
Contributions	8	2	2
Benefits paid	(6)	(6)	(5)
Return on plan assets	6	7	6
Gain (loss) on plan assets	2	(11)	(8)
Foreign exchange losses	(2)	—	—
Fair value of plan assets, end of year	$ 85	$ 77	$ 85

Funded Status of Plan	2003	2002	2001
Fair value of plan assets	$ 85	$ 77	$ 85
Benefit obligation	(118)	(108)	(95)
Excess assets (obligation)	(33)	(31)	(10)
Unrecognized past service costs	1	1	—
Unrecognized losses	32	27	6
Accrued benefit liability	$ —	$ (3)	$ (4)

The composition of the defined benefit pension plan's assets at year-end 2003 was U.S. common equities 15 percent, Canadian common equities 27 percent, Canadian mutual funds 12 percent, Canadian government bonds 33 percent and Canadian corporate bonds 13 percent.

During 2003 Husky contributed $8 million to the defined benefit pension plan's assets, $6 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute a similar amount in 2004.

Post-retirement Health and Dental Care Plan

The status of the post-retirement health and dental care plan at December 31 was as follows:

Benefit Obligation	2003	2002	2001
Benefit obligation, beginning of year	$21	$16	$14
Current service cost	2	1	1
Interest cost	1	1	1
Benefits paid	(1)	—	—
Actuarial losses	—	3	—
Benefit obligation, end of year	$23	$21	$16

Funded Status of Plan	2003	2002	2001
Benefit obligation	$(23)	$(21)	$(16)
Unrecognized losses	3	4	—
Accrued benefit liability	$(20)	$(17)	$(16)

The assumed health care cost trend can have a significant effect on the amounts reported for Husky's post-retirement health and dental care plan. A one percent increase and decrease in the assumed trend rate would have the following effect:

	1% Increase	1% Decrease
Effect on total service and interest cost components	$1	$—
Effect on post-retirement benefit obligation	$4	$(3)

Pension Expense and Post-retirement Health and Dental Care Expense

The expenses for the years ended December 31 were as follows:

Pension Expense	2003	2002	2001
Defined benefit pension plan			
Employer current service cost	$ 2	$ 2	$ 1
Interest cost	7	7	6
Expected return on plan assets	(6)	(7)	(6)
Amortization of net actuarial losses	2	—	—
	5	2	1
Defined contribution pension plan	11	10	8
Total expense	$16	$12	$ 9

Post-retirement Health and Dental Care Expense	2003	2002	2001
Employer current service cost	$2	$1	$1
Interest cost	1	1	1
Total expense	$3	$2	$2

Note 18 Related Party Transactions

Husky, in the ordinary course of business, entered into a lease for an eight-year term effective September 1, 2000 with Western Canadian Place Ltd. The terms of the lease provide for the lease of office space, management services and operating costs at commercial rates. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. During 2003 Husky paid approximately $17 million for office space in Western Canadian Place.

Husky did not have any customers that constituted more than five percent of total sales and operating revenues during 2003.

Note 19 Financial Instruments and Risk Management

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities

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 these instruments. The estimated fair value of the long-term debt at December 31 was as follows:

	2003		2002		2001	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$1,698	$1,869	$2,385	$2,579	$2,092	$2,143

The fair value of the long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates.

Unrecognized Gains (Losses) on Derivative Instruments

	2003	2002	2001
Commodity price risk management			
Natural gas	$ (8)	$(4)	$15
Crude oil	(109)	6	—
Power consumption	2	—	—
Interest rate risk management			
Interest rate swaps	31	86	4
Foreign currency risk management			
Foreign exchange contracts	(19)	(7)	(29)
Foreign exchange forwards	15	(5)	—

Commodity Price Risk Management

Natural Gas

At December 31, 2003 the Company had hedged 70 mmcf of natural gas per day at NYMEX for February and March 2004 at an average price of U.S. $6.69 per mmbtu and 20 mmcf of natural gas per day at NYMEX for April 2004 at an average price of U.S. $6.38 per mmbtu. During 2003 the impact of the 2003 hedge program was a gain of $24 million.

At December 31, 2003 the Company had also hedged 7.5 mmcf of natural gas per day at NYMEX for the years 2004 and 2005 at an average price of U.S. $1.92 per mcf. During 2003 the impact was a loss of $8 million (2002 and 2001 — insignificant).

Crude Oil

At December 31, 2003 the Company had hedged crude oil averaging 85,000 bbls per day from January to December 2004 at an average fixed WTI price of U.S. $27.46 per bbl. The impact of the hedge program for 2003 was a loss of $36 million (2002 — gain of $5 million).

Power Consumption

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

Natural Gas Contracts

The Company has a portfolio of fixed and basis 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 sale contract prices. At December 31, 2003 the Company had the following offsetting physical purchase and sale contracts:

	Volumes *(mmcf)*	Unrecognized Gain (Loss)
Physical purchase contracts	16,971	$—
Physical sale contracts	(16,971)	$ 2

Interest Rate Risk Management

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, 2003 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)
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps
7.55% debentures	U.S. $200	November 15, 2011	U.S. LIBOR + 194 bps

During 2003 the Company realized a gain of $17 million (2002 — gain of $29 million; 2001 — gain of $2 million) from interest rate risk management activities.

In 2003, the Company unwound three interest rate swaps. Proceeds of $44 million have been deferred and are being amortized to income over the remaining term of the debt.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange rate fluctuations by balancing the U.S. dollar denominated cash flows from operations with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At December 31, 2003 the Company had the following cross currency debt swaps:

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

The Company hedged U.S. dollar revenues for various amounts and maturities through 2005 through the use of foreign exchange forwards. The total amount hedged using long-dated forwards at December 31, 2003 was U.S. $52 million at an average forward rate of $1.5625. The total amount hedged using short-dated forwards at December 31, 2003 was U.S. $70 million at an average forward rate of $1.3166.

During 2003 the Company realized a loss of $56 million (2002 — loss of $11 million; 2001 — loss of $4 million) from foreign currency risk management activities.

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.

Note 20 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 from 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

	2003	2002	2001
Net earnings	$1,321	$ 804	$ 654
Adjustments:			
Full cost accounting(a)	80	88	(544)
Related income taxes	(30)	(37)	235
Foreign currency translation on capital securities(b)	67	3	(20)
Related income taxes	(12)	(1)	5
Return on capital securities(b)	(29)	(32)	(33)
Related income taxes	11	11	14
Derivatives and hedging(c)	(1)	22	(30)
Related income taxes	1	(9)	12
Gain (loss) on energy trading contracts(c)	(15)	(2)	20
Related income taxes	6	1	(8)
Asset retirement obligations(d)	15	—	—
Related income taxes	(2)	—	—
Stock-based compensation(e)	(46)	—	—
Accounting for income taxes(f)	—	(37)	(14)
Earnings before cumulative effect of change in accounting principle under U.S. GAAP	1,366	811	291
Cumulative effect of change in accounting principle, net of tax(c)(d)	9	—	6
Net earnings under U.S. GAAP	$1,375	$ 811	$ 297
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic	419.5	417.4	416.1
Diluted	421.5	419.3	418.6
Earnings per share before cumulative effect of change in accounting principle under U.S. GAAP			
Basic	$ 3.26	$ 1.94	$ 0.70
Diluted	$ 3.24	$ 1.93	$ 0.70
Earnings per share under U.S. GAAP			
Basic	$ 3.28	$ 1.94	$ 0.71
Diluted	$ 3.26	$ 1.93	$ 0.71

Condensed Consolidated Balance Sheets

	2003		2002		2001	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets(c)	$ 865	$ 924	$ 1,144	$ 1,292	$ 626	$ 756
Property, plant and equipment, net(a)(d)	10,685	10,251	9,347	8,670	8,715	7,950
Other assets(c)(j)	232	236	84	89	29	33
	$11,782	$11,411	$10,575	$10,051	$9,370	$8,739
Current liabilities(b)(c)(j)	$ 1,456	$ 1,635	$ 1,215	$ 1,301	$1,049	$1,187
Long-term debt(b)(c)	1,439	1,761	1,964	2,406	1,948	2,306
Other long-term liabilities(d)	390	519	266	266	228	228
Future income taxes(a)(b)(c)(d)(f)(j)	2,608	2,372	2,003	1,772	1,659	1,361
Capital securities and accrued return(b)	298	—	364	—	367	—
Share capital and contributed surplus(g)(h)	3,457	3,737	3,406	3,640	3,397	3,631
Retained earnings	2,134	1,478	1,357	683	722	23
Accumulated other comprehensive income						
Cash flow hedges, net of tax(c)	—	(76)	—	(7)	—	3
Minimum pension liability, net of tax(j)	—	(15)	—	(10)	—	—
	$11,782	$11,411	$10,575	$10,051	$9,370	$8,739

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

	2003		2002		2001	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings (deficit), beginning of year	$1,357	$ 683	$ 722	$ 23	$253	$(124)
Net earnings	1,321	1,375	804	811	654	297
Dividends on common shares	(580)	(580)	(151)	(151)	(150)	(150)
Capital securities, net of tax and foreign exchange(b)	36	—	(18)	—	(35)	—
Retained earnings, end of year	$2,134	$1,478	$1,357	$ 683	$722	$ 23
Accumulated other comprehensive income, beginning of year	$ —	$ (17)	$ —	$ 3	$ —	$ —
Cumulative effect of change in accounting, net of tax(c)	—	—	—	—	—	(10)
Cash flow hedges, net of tax(c)	—	(69)	—	(10)	—	13
Minimum pension liability, net of tax(j)	—	(5)	—	(10)	—	—
Accumulated other comprehensive income, end of year	$ —	$ (91)	$ —	$ (17)	$ —	$ 3

Condensed Consolidated Statements of Earnings and Comprehensive Income

	2003		2002		2001	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues(c)(i)	$7,658	$6,943	$6,384	$5,778	$6,596	$5,606
Costs and expenses(b)(c)(e)(i)	4,732	4,012	4,117	3,488	4,614	3,654
Accretion expense(d)	—	22	—	—	—	—
Depletion, depreciation and amortization(a)(d)	1,058	941	939	851	807	1,351
Interest — net(b)	73	102	104	136	101	134
Earnings before income taxes	1,795	1,866	1,224	1,303	1,074	467
Income taxes(a)(b)(c)(d)(f)	474	500	420	492	420	176
Earnings before cumulative effect of change in accounting principle	1,321	1,366	804	811	654	291
Cumulative effect of change in accounting principle, net of tax(c)(d)	—	9	—	—	—	6
Net earnings	1,321	1,375	804	811	654	297
Other comprehensive income(c)(j)	—	74	—	20	—	(3)
Comprehensive income	$1,321	$1,449	$ 804	$ 831	$ 654	$ 294

Condensed Consolidated Statements of Cash Flows

	2003	2002	2001
Cash flow — operating activities — Canadian GAAP	$ 2,572	$ 1,892	$ 1,930
Adjustments			
Return on capital securities payment	(29)	(31)	(30)
Settlement of asset retirement liabilities	(34)	—	—
Cash flow — operating activities — U.S. GAAP	2,509	1,861	1,900
Cash flow — financing activities — Canadian GAAP	(800)	3	(423)
Adjustments			
Return on capital securities payment	29	31	30
Cash flow — financing activities — U.S. GAAP	(771)	34	(393)
Cash flow — investing activities — Canadian GAAP	(2,075)	(1,589)	(1,507)
Adjustments			
Settlement of asset retirement liabilities	34	—	—
Cash flow — investing activities — U.S. GAAP	(2,041)	(1,589)	(1,507)
Change in cash and cash equivalents	$ (303)	$ 306	$ —

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 and major development projects 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) The Company records the capital securities as a component of equity and the return and foreign exchange gains or losses 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 and foreign exchange gains or losses would be charged to earnings. See note 15, Capital Securities.

(c) 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 million and $10 million, respectively, and recorded a resulting cumulative effect of change in accounting principle to increase earnings by $6 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 $4 million and $23 million, respectively, and a resulting reduction of other comprehensive income within shareholders' equity of $10 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 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 cumulative effect of change in accounting principle increased earnings per share under U.S. GAAP by $0.01 (basic and diluted).

At December 31, 2003 the Company recorded additional assets and liabilities for U.S. GAAP purposes of $52 million (2002 — $111 million; 2001 — $22 million) and $172 million (2002 — $122 million; 2001 — $38 million), respectively, for the fair values of derivative financial instruments. During 2003, a gain of $1 million, net of tax (2002 — gain of $11 million; 2001 — insignificant), 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 loss of $2 million, net of tax (2002 and 2001 — gain of $1 million), 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 $69 million loss, net of tax (2002 — gain of $10 million; 2001 — loss of $13 million), 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 2003.

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 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, at December 31, 2003 the Company recorded additional assets and liabilities of $7 million (2002 — $37 million; 2001 — $114 million) and $5 million (2002 — $19 million; 2001 — $88 million), respectively, and included the resulting unrealized loss, net of tax, in earnings for the year of $9 million (2002 — loss of $1 million; 2001 — gain of $11 million).

Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues.

(d) In 2003, the Company adopted FAS 143, ''Accounting for Asset Retirement Obligations'', which requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related tangible long-lived asset. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset. The liability is accreted at the end of each period through charges to accretion expense. The change was effective January 1, 2003, and the related cumulative effect of change in accounting principle to net earnings to December 31, 2002 was an increase of $9 million ($20 million before income taxes) or $0.02 per share (diluted). At January 1, 2003, the change resulted in an increase to net property, plant and equipment of $58 million, an increase in the asset retirement obligations which are included in other long-term liabilities of $38 million, an increase to the future income tax liability of $11 million and an increase to retained earnings of $9 million. The application of FAS 143 did not have a material impact on the Company's depreciation, depletion and amortization rate. There was no impact on the Company's cash flow as a result of adopting FAS 143.

The following table provides changes to asset retirement obligations for the year ended December 31, 2003:

Asset retirement obligations, January 1, 2003	$286
Liabilities incurred during year	17
Acquisition of Marathon Canada	38
Divestitures	(5)
Revision of previous estimate	108
Liabilities settled during year	(34)
Accretion expense	22
Asset retirement obligations, December 31, 2003	$432

The following table shows the effect on the Company's net earnings and earnings per share as if FAS 143 had been in effect in prior years. There was a $10 million increase to net earnings for each of the years ended December 31, 2002 and 2001.

	As at and for the years ended December 31	
	2002	**2001**
As reported		
Net earnings under U.S. GAAP	$ 811	$ 297
Earnings per share under U.S. GAAP		
Basic	$1.94	$0.71
Diluted	$1.93	$0.71
Pro forma		
Net earnings under U.S. GAAP	$ 821	$ 307
Earnings per share under U.S. GAAP		
Basic	$1.97	$0.74
Diluted	$1.96	$0.73
Asset retirement obligations		
Beginning of year	$ 269	$ 255
End of year	$ 286	$ 269

(e) On September 3, 2003 the Company modified the exercise price of all outstanding options. Under U.S. GAAP these options must be accounted for using variable accounting where the in-the-money portion of the vested stock options outstanding is required to be adjusted through the statement of earnings as compensation expense over the remaining vesting period. The amount of stock-based compensation expense charged to earnings for the year ended December 31, 2003 was $46 million. The compensation expense will be revalued at each reporting date based on the share price and the number of vested stock options outstanding.

(f) The liability method under Canadian GAAP 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 in 2000, the deficit of Husky Oil Limited of $160 million 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 2003 were $232 million (2002 — $256 million; 2001 — $272 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. At December 31, 2003 the additional minimum liability was increased by $6 million (2002 — $19 million) with a decrease to other comprehensive income of $5 million (2002 — decrease of $10 million), net of tax.

Additional U.S. GAAP Disclosures

Acquisition of Marathon Canada

As described in note 7, Acquisition of Marathon Canada, the Company purchased all of the outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. This transaction increased the reserve base and created cost efficiencies, increasing shareholder value.

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 2003, 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, 2003. During 2003, 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, no compensation expense has been charged to income at the time of the option grants. On September 3, 2003 the Company modified the exercise price of all outstanding options, resulting in the use of variable accounting for these modified stock options. The compensation expense recorded under variable accounting has been removed from the pro forma amounts indicated below. 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 earnings per share for the years ended December 31, 2003, 2002 and 2001 would have been the pro forma amounts indicated below:

	2003		2002		2001	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
Net earnings	$1,375	$1,407	$ 811	$ 798	$ 297	$ 284
Earnings per share						
— Basic	$ 3.28	$ 3.35	$1.94	$1.91	$0.71	$0.68
— Diluted	$ 3.26	$ 3.34	$1.93	$1.90	$0.71	$0.68

The fair values of all common share options granted are estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of options granted during the year and the assumptions used in their determination are the same as described in note 16.

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 as calculated under U.S. GAAP for the years ended December 31 were as follows:

	2003	2002	2001
Depletion, depreciation and amortization per boe(1)	$7.57	$6.96	$6.88

(1) Excludes the 2001 ceiling test write down.

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation 46 ''Accounting for Variable Interest Entities'' (''FIN 46'') that requires the consolidation of Variable Interest Entities (''VIEs''). VIEs are entities that have insufficient equity or their equity investors lack one or more of the specified elements that a controlling entity would have. The VIEs are controlled through financial interests that indicate control (referred to as ''variable interests''). Variable interests are the rights or obligations that expose the holder of the variable interest to expected losses or expected residual gains of the entity. The holder of the majority of an entity's variable interests is considered the primary beneficiary of the VIE and is required to consolidate the VIE. In December 2003 the FASB issued FIN 46R which superceded FIN 46 and restricts the scope of the definition of entities that would be considered VIEs that require consolidation. The Company does not believe FIN 46R results in the consolidation of any additional entities that existed at December 31, 2003.

Exhibit 3

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2003

Exhibit 3

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 2, 2004

Management's Discussion and Analysis is the Company's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Company's financial position and prospects. It should be read in conjunction with the Consolidated Financial Statements and notes thereto and the Supplemental Information on Oil and Gas Exploration and Production Activities. 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 20 of the Consolidated Financial Statements. The following discussion and analysis refers primarily to 2003 as compared with 2002, unless otherwise indicated. Refer to the section ''Results of Operations for 2002 Compared with 2001'' for an abridged discussion. All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. The calculations of barrels of oil equivalent (''boe'') and thousand 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. Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties, and prices are those realized by the Company, which include the effect of hedging gains and losses.

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 as an indicator of the Company's financial performance. The Company's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations generated by each business segment represents a measurement of financial performance for which each reporting business segment is responsible. The other items required to arrive at consolidated cash flow from operations are considered to be a corporate responsibility.

Certain of the statements set forth under ''Management's Discussion and Analysis'' 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 the Company'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 the Company. These factors include, but are not limited to, the matters described under the heading ''Business Environment''. Should one or more of these events occur, or should any of the underlying assumptions prove incorrect, the Company's actual results and plans for 2004 and beyond could differ materially from those expressed in the forward-looking statements. The Company does not undertake to update, revise or correct any of the forward-looking information. Such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: ''CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995''. Refer to the section ''Forward-looking Statements''.

OVERVIEW

Summary of Results

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 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 marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.
- The refined products segment includes the refining of crude oil and the marketing of refined petroleum products including asphalt products.

Segmented Financial Summary

	Year ended December 31				
	2003	% Change	2002	% Change	2001
	($ millions, except where indicated)				
Sales and operating revenues, net of royalties	$7,658	20	$6,384	(3)	$6,596
Cash flow from operations	2,459	17	2,096	8	1,946
Segmented earnings					
Upstream	$1,048	52	$ 688	43	$ 482
Midstream	185	15	161	(37)	256
Refined Products	28	(13)	32	(49)	63
Corporate and eliminations	60	178	(77)	48	(147)
Net earnings	$1,321	64	$ 804	23	$ 654
Per share — Basic	$ 3.23	72	$ 1.88	26	$ 1.49
— Diluted	3.22	71	1.88	27	1.48
Dividends declared per share	1.38	283	0.36	—	0.36
Return on equity *(percent)*	24.0		16.7		15.4
Return on average capital employed *(percent)*	18.0		12.2		10.9

Business Environment

Husky's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

- Crude oil and natural gas prices
- Cost to find, develop, produce and deliver crude oil and natural gas
- Demand for and ability to deliver natural gas
- The exchange rate between the Canadian and U.S. dollars
- Refined products margins
- Demand for Husky's pipeline capacity
- Demand for refined petroleum products
- Government regulations
- Cost of capital

Average Benchmark Prices and U.S. Exchange Rate

		2003	2002	2001
West Texas Intermediate (''WTI'') (1)	*(U.S. $/bbl)*	$31.04	$26.08	$25.97
Canadian par light crude 0.3% sulphur	*($/bbl)*	$43.56	$40.28	$39.39
NYMEX natural gas (1)	*(U.S. $/mmbtu)*	$ 5.39	$ 3.25	$ 4.38
NIT natural gas	*($/GJ)*	$ 6.35	$ 3.86	$ 5.97
WTI/Lloyd blend differential	*(U.S. $/bbl)*	$ 8.55	$ 6.47	$10.74
U.S./Canadian dollar exchange rate	*(U.S. $)*	$0.716	$0.637	$0.646

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

Commodity Price Risk

Husky's earnings depend largely on the profitability of its upstream business, which is significantly affected by fluctuations in oil and gas prices. Commodity prices have been, and are expected to continue to be, volatile due to a number of factors beyond Husky's control. Refer to the section ''Financial and Derivative Instruments'' for a discussion of the Company's use of hedging contracts.

Crude Oil

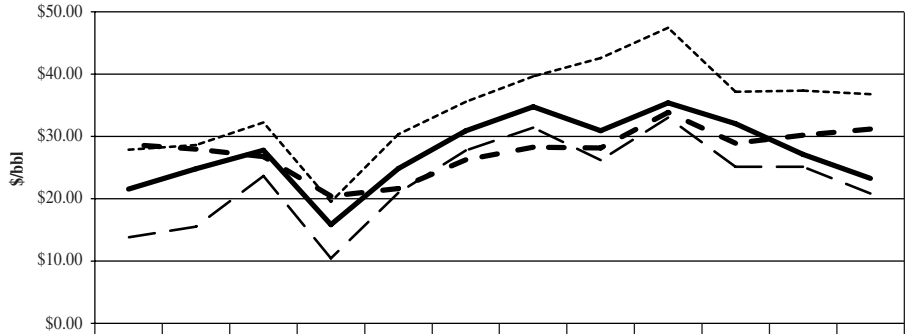
The prices received for the crude oil and NGL sold by Husky are related to the price of crude oil in world markets. Prices for heavy crude oil and other lesser quality crudes trade at a discount or differential to light crude oil. These prices are further affected by the use of hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price.

Benchmark crude oil prices averaged higher in 2003 compared with 2002. The price for West Texas Intermediate (''WTI'') crude oil averaged U.S. $32.70/bbl in January 2003 and fluctuated between monthly averages of U.S. $35.73/bbl and U.S. $28.07/bbl during the remainder of the year.

During 2003 buoyant world crude oil prices resulted from production quotas set by the Organization of Petroleum Exporting Countries (''OPEC''), Nigerian and Venezuelan production restrictions and the war in Iraq. Iraqi production averaged approximately 350,000 bbls/day from April through July 2003. In August Iraqi production recovered considerably and averaged 1,400,000 bbls/day from August through October 2003 or approximately 70 percent of normal pre-war levels. OPEC has maintained a greater degree of production discipline over the past three years with the intention of maintaining prices within a U.S. $22/bbl — U.S. $28/bbl price range. Toward the end of 2003, OPEC announced cuts to its production quotas that were intended to keep prices within the price band. Numerous factors could affect world crude oil prices in the remainder of 2004. Early January 2004 commercial crude oil inventories were significantly lower than the five-year average. Low crude oil inventories restrict the refiners' ability to increase distillate production, should protracted cold weather increase heating demand.

During 2003 heavy crude oil differentials averaged U.S. $8.55/bbl for WTI/Lloyd blend compared with U.S. $6.47/bbl during 2002. The wider differential tends to reduce Husky's overall financial results as the Company's crude oil production is weighted toward heavier gravity crudes. In periods of wider differentials, Husky's heavy oil upgrader offsets in part the impact of lower heavy crude prices.

WTI and Husky Realized Crude Oil Prices



	Q1-01	Q2-01	Q3-01	Q4-01	Q1-02	Q2-02	Q3-02	Q4-02	Q1-03	Q2-03	Q3-03	Q4-03
West Texas Intermediate ("WTI") (U.S. $)	$28.72	$27.96	$26.76	$20.43	$21.64	$26.25	$28.27	$28.15	$33.86	$28.91	$30.20	$31.18
Husky realized light crude oil price (C $)	$27.87	$28.62	$32.24	$19.51	$30.35	$35.56	$39.64	$42.58	$47.44	$37.17	$37.35	$36.78
Husky realized medium crude oil price (C $)	$21.55	$24.81	$27.78	$15.84	$24.84	$30.90	$34.76	$30.92	$35.39	$32.05	$27.12	$23.27
Husky realized heavy crude oil price (C $)	$13.81	$15.52	$23.65	$10.44	$20.95	$27.75	$31.41	$26.20	$33.02	$25.13	$25.13	$20.84

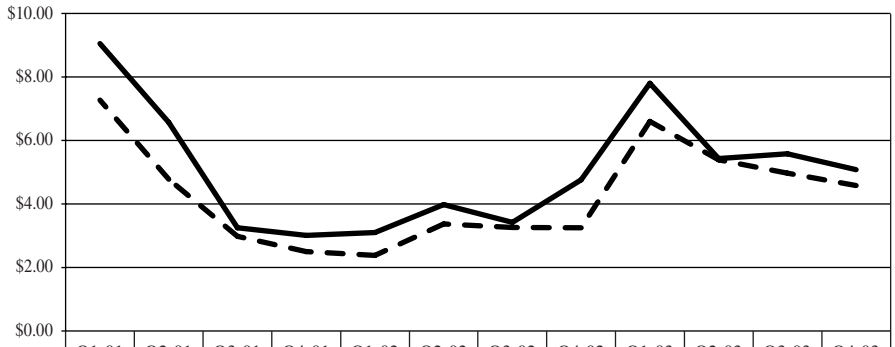
Natural Gas

The price of natural gas in North America is affected by regional supply and demand factors, particularly those affecting the United States such as weather conditions, 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 such as OPEC.

Throughout the last five months of 2003 natural gas prices on the New York Mercantile Exchange (''NYMEX'') drifted lower, averaging just over U.S. $5/mmbtu. With the arrival of colder weather at the end of November, prices on the NYMEX began to increase and the near-month price on December 31, 2003 for February 2004 delivery was U.S. $6.19/mmbtu. At the beginning of January 2004 natural gas storage in the U.S. was just above the five-year average.

The selling price for Husky's natural gas is based either on fixed price contracts, spot prices, NYMEX or other regional market prices. The prices received are further affected by the Company's hedging contracts, which provide for payments or receipts depending on whether the underlying commodity price is higher or lower than an agreed upon strike price. Refer to ''Financial and Derivative Instruments'' for a discussion of the Company's use of hedging contracts.

NYMEX Natural Gas and Husky Realized Natural Gas Prices



	Q1-01	Q2-01	Q3-01	Q4-01	Q1-02	Q2-02	Q3-02	Q4-02	Q1-03	Q2-03	Q3-03	Q4-03
NYMEX natural gas (U.S. $/mmbtu)	$7.27	$4.78	$2.98	$2.50	$2.38	$3.37	$3.26	$3.25	$6.60	$5.39	$4.97	$4.58
Husky realized natural gas price (C $/mcf)	$9.05	$6.57	$3.25	$3.01	$3.10	$3.98	$3.42	$4.76	$7.80	$5.43	$5.58	$5.08

Upgrading Differential

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 from heavy oil production.

Refined Products Margins

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

Integration

Husky's production of light, medium and heavy crude oil and natural gas 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 commodity price volatility. Although predominantly an oil and gas producer, Husky's integrated organization is such that the upstream business segment's output provides input to the midstream and refined products segments.

Foreign Exchange Risk

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 oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities and correspondingly an increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. The majority of Husky's expenditures 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, 2003, 74 percent or $1.5 billion of Husky's long-term debt and capital securities was denominated in U.S. dollars. The Cdn./U.S. exchange rate at the end of 2003 was $1.29. The percentage of Husky's long-term debt exposed to the Cdn./U.S. exchange rate decreases to 54 percent when the cross currency swaps are included. Refer to ''Financial and Derivative Instruments''.

Interest Rates

The Company maintains a portion of its debt in floating rate facilities which are exposed to interest rate fluctuations. The Company will occasionally fix its floating rate debt or create a variable rate for its fixed rate debt using derivative financial instruments. Refer to ''Financial and Derivative Instruments''.

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, exchange controls, currency fluctuations, royalty and tax increases, import and export regulations and other foreign laws or policies affecting foreign trade or investment.

Sensitivity Analysis

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

Sensitivity Analysis

Item	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
		($ millions)	($/share) (4)	($ millions)	($/share) (4)
WTI benchmark crude oil price					
Excluding hedges	U.S. $1.00/bbl	93	0.22	63	0.15
Including hedges	U.S. $1.00/bbl	54	0.13	34	0.08
NYMEX benchmark natural gas price (1)					
Excluding hedges	U.S. $0.20/mmbtu	34	0.08	21	0.05
Including hedges	U.S. $0.20/mmbtu	18	0.04	10	0.02
Light/heavy crude oil differential (2)	Cdn. $1.00/bbl	(25)	(0.06)	(16)	(0.04)
Light oil margins	Cdn. $0.005/litre	15	0.04	9	0.02
Asphalt margins	Cdn. $1.00/bbl	8	0.02	5	0.01
Exchange rate (U.S. $ per Cdn. $) (3)					
Including hedges	U.S. $0.01	(50)	(0.12)	(34)	(0.08)

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

(2) Includes impact of upstream and upgrading operations only.

(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items. The impact of the Canadian dollar strengthening by U.S. $0.01 would be an increase of $8 million in net earnings based on December 31, 2003 U.S. dollar denominated debt levels.

(4) Based on December 31, 2003 common shares outstanding of 422 million.

Husky's Business Plan

Husky will continue to execute its long-term business plan, which is expected to increase reserves and production in the upstream business segment through selective acquisitions and effective exploration and development programs.

Husky will also continue to enhance growth and returns through expansion, upgrading and optimization of the midstream and refined products businesses.

The light and medium gravity crude oil potential of the Western Canada Sedimentary Basin, although considerable, is generally believed to be composed of smaller accumulations. Husky plans to optimize production from its properties in the Western Canada Sedimentary Basin through programs to improve recovery and through acquisitions and dispositions. Husky benefits from having a significant position in several key producing areas in Western Canada. Husky is the operator of the majority of its operations and has extensive infrastructure, which affords opportunities for cost control and economies of scale.

Husky plans to more than offset production declines from light and medium crude oil properties in the Western Canada Sedimentary Basin by further exploitation of heavy oil in the Lloydminster area of Alberta and Saskatchewan, development of oil sands properties in Alberta, production from the White Rose offshore project and production from projects offshore China. In addition, 2004 plans include an oil exploration program in an area new to Husky in the central Mackenzie region of the Northwest Territories.

The natural gas potential of the Western Canada Sedimentary Basin is considered to be favourable both for shallow gas on the undisturbed plains and larger deep accumulations in the Deep Basin and foothills overthrust areas. Husky's natural gas production is expected to increase as a result of exploration concentrated in these areas west of the fifth meridian in Alberta and British Columbia and natural gas development activity throughout the Basin, as well as through selective acquisitions and asset rationalization.

In 2004 Husky intends to invest $2.1 billion in capital programs. Capital totalling $1.15 billion is planned to be spent on upstream programs located throughout the Western Canada Sedimentary Basin, $585 million on programs offshore the East Coast of Canada and $65 million on international programs primarily offshore China. Capital programs in the midstream segment will total $100 million primarily for further debottlenecking of the Lloydminster Upgrader and $150 million in the refined products segment primarily for further upgrading of the marketing outlet system and construction of an ethanol production facility. Husky plans to invest $30 million in corporate areas in 2004.

Husky's 2004 business plan assumes that:

- WTI will average U.S. $26.50/bbl and the WTI/Lloyd blend differential will average U.S. $6.96/bbl
- NYMEX natural gas price will average U.S. $5.25/mcf
- the Canadian dollar will average U.S. $0.73
- U.S. $LIBOR will average 2.50 percent
- Husky's total production will average 320 to 350 mboe/day. Production in 2004 comprises 67 to 76 mbbls/day of light crude oil and NGL, 35 to 40 mbbls/day of medium crude oil, 105 to 115 mbbls/day of heavy crude oil and 670 to 710 mmcf/day of natural gas

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 speculative purposes.

During 2003 Husky entered into contractual arrangements whereby between approximately 25 percent and 27 percent of 2004 planned annual production has been hedged. Crude oil production totalling 31 mmbbls has been hedged at an average price of U.S. $27.46/bbl throughout 2004 and 4.8 bcf of natural gas production has been hedged at an average price of U.S. $6.65/mmbtu from February to April 2004. This will protect cash flow and earnings in 2004 and facilitate the execution of 2004 capital programs. In addition, Husky has hedged a portion of its power purchases. From January to December 2004, 329,400 MWh have been hedged at an average price of $46.72/MWh.

RESULTS OF OPERATIONS

Upstream

2003 Compared with 2002

Husky's earnings from the upstream segment increased by $360 million (52 percent) to $1,048 million in 2003 from $688 million in 2002.

Upstream Earnings Summary

	Year ended December 31		
	2003	2002	2001
		($ millions)	
Gross revenues	$3,796	$3,120	$2,667
Royalties	584	460	502
Hedging (gain)/loss	26	(5)	—
Net revenues	3,186	2,665	2,165
Operating and administrative expenses	855	729	648
DD&A	958	851	728
Income taxes	325	397	307
Earnings	$1,048	$ 688	$ 482

Husky's total revenues from upstream operations were $3,796 million in 2003 compared with $3,120 million in 2002 primarily due to:

- higher price realization for crude oil and natural gas
- higher sales volumes of light and heavy crude oil and natural gas

the effect of which was partially offset by:

- lower sales volume of medium crude oil
- higher unit operating costs

Higher production volumes of heavy crude oil were primarily due to:

- the ongoing Lloydminster heavy oil development programs and progress at the Bolney/Celtic steam assisted gravity drainage thermal project

Operating costs per unit of production increased 11 percent in 2003 compared with 2002 primarily as a result of:

- higher energy costs
- higher operating and maintenance costs for light/medium crude oil properties under secondary and tertiary recovery schemes in Western Canada
- higher operating and maintenance costs for the extensive facilities associated with shallow gas production in Western Canada

partially offset by:

- lower unit operating costs at Terra Nova and Wenchang

Depletion, depreciation and amortization (''DD&A'') increased to $8.40/boe in 2003 from $7.76/boe in 2002 and primarily resulted from:

- higher maintenance capital requirements for properties under secondary and tertiary recovery and shallow natural gas operations
- offshore operations that require substantial infrastructure capital
- acquired oil and gas properties which, in accordance with the purchase method of accounting, are recorded at fair value

Income taxes with respect to the upstream business segment decreased in 2003 to $325 million from $397 million in 2002 despite higher pre-tax earnings. Income taxes in 2003 were partially offset by a number of non-recurring

benefits. On June 13, 2003, Bill C-48 received first reading in the House of Commons and thus was considered to be substantively enacted. This amendment to the Income Tax Act reduces the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment will be phased in over a five-year period. The total benefit recorded with respect to Bill C-48 was $141 million. In addition, a non-recurring upstream benefit totalling $18 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. Both benefits reduced future income taxes related to upstream operations.

During 2002, a non-recurring benefit of $23 million was recorded with respect to Alberta and British Columbia income tax rate reductions.

Net Revenue Variance Analysis

	Crude Oil & NGL	Natural Gas	Other	Total
		($ millions)		
Year ended December 31, 2001				
Net revenues	$1,262	$ 873	$30	$2,165
Price changes	573	(342)	8	239
Volume changes	218	(7)	—	211
Royalties	(71)	113	—	42
Hedging	5	—	—	5
Processing	—	—	3	3
Year ended December 31, 2002				
Net revenues	1,987	637	41	2,665
Price changes	85	450	—	535
Volume changes	59	58	—	117
Royalties	16	(140)	—	(124)
Hedging	(50)	19	—	(31)
Processing	—	—	24	24
Year ended December 31, 2003				
Net revenues	$2,097	$1,024	$65	$3,186

Daily Production, before Royalties

		Year ended December 31		
		2003	2002	2001
Light crude oil & NGL	*(mbbls/day)*	71.6	65.4	46.4
Medium crude oil	*(mbbls/day)*	39.2	44.8	47.2
Heavy crude oil	*(mbbls/day)*	99.9	95.1	83.8
Natural gas	*(mmcf/day)*	610.6	569.2	572.6
Barrels of oil equivalent (6:1)	*(mboe/day)*	312.5	300.2	272.8

Average Realized Prices

		Year ended December 31		
		2003	2002	2001
Light crude oil & NGL	*($/bbl)*	$39.53	$36.17	$33.15
Hedging (gain)/loss		0.80	(0.09)	—
Light crude oil & NGL price realized		$38.73	$36.26	$33.15
Medium crude oil	*($/bbl)*	$31.42	$30.16	$23.69
Hedging (gain)/loss		1.85	(0.19)	—
Medium crude oil price realized		$29.57	$30.35	$23.69
Heavy crude oil price realized	*($/bbl)*	$25.87	$26.60	$17.02
Natural gas price	*($/mcf)*	$ 5.86	$ 3.83	$ 5.47
Hedging (gain)/loss		(0.08)	—	—
Natural gas price realized		$ 5.94	$ 3.83	$ 5.47

Upstream Revenue Mix

	Year ended December 31		
	2003	2002	2001
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	28%	24%	14%
Medium crude oil	11%	25%	28%
Heavy crude oil	27%	25%	16%
Natural gas	34%	26%	42%
Total	100%	100%	100%

Effective Royalty Rates

	Year ended December 31		
	2003	2002	2001
Percentage of upstream sales revenues			
Light crude oil & NGL	12%	13%	21%
Medium crude oil	18%	17%	18%
Heavy crude oil	11%	11%	9%
Natural gas	21%	18%	23%
Total	16%	15%	19%

Operating Netbacks

Western Canada

Light Crude Oil Netbacks (1)

	Year ended December 31		
	2003	2002	2001
		(per boe)	
Sales revenues	$39.91	$33.66	$34.25
Royalties	7.28	4.55	5.76
Hedging (gain)/loss	0.56	(0.17)	—
Operating costs	9.27	10.46	8.15
Netback	$22.80	$18.82	$20.34

Medium Crude Oil Netbacks (1)

	Year ended December 31		
	2003	2002	2001
		(per boe)	
Sales revenues	$31.57	$29.92	$23.86
Royalties	5.28	5.59	4.39
Hedging (gain)/loss	1.79	(0.19)	—
Operating costs	9.53	7.19	7.18
Netback	$14.97	$17.33	$12.29

Heavy Crude Oil Netbacks (1)

	Year ended December 31		
	2003	2002	2001
		(per boe)	
Sales revenues	$25.98	$26.48	$17.20
Royalties	2.76	3.45	1.93
Operating costs	9.09	7.18	7.40
Netback	$14.13	$15.85	$ 7.87

Natural Gas Netbacks (2)

	Year ended December 31		
	2003	2002	2001
		(per mcfge)	
Sales revenues	$5.79	$3.97	$5.39
Royalties	1.29	0.81	1.30
Hedging (gain)/loss	(0.08)	—	—
Operating costs	0.79	0.70	0.58
Netback	$3.79	$2.46	$3.51

Total Western Canada Upstream Netbacks (1)

	Year ended December 31		
	2003	2002	2001
		(per boe)	
Sales revenues	$31.58	$27.04	$26.42
Royalties	5.48	4.46	5.04
Hedging (gain)/loss	0.14	(0.05)	—
Operating costs	7.56	6.54	6.08
Netback	$18.40	$16.09	$15.30

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

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

Terra Nova Crude Oil Netbacks

	Year ended December 31		
	2003	2002	2001
		(per boe)	
Sales revenues	$38.91	$35.47	$ —
Royalties	0.81	0.36	—
Hedging (gain)/loss	1.95	—	—
Operating costs	3.16	3.62	—
Netback	$32.99	$31.49	$ —

Wenchang Crude Oil Netbacks

	Year ended December 31		
	2003	2002	2001
		(per boe)	
Sales revenues	$41.45	$44.36	$ —
Royalties	3.80	2.65	—
Operating costs	1.94	2.15	—
Netback	$35.71	$39.56	$ —

Total Upstream Netbacks (1)

	Year ended December 31		
	2003	2002	2001
		(per boe)	
Sales revenues	$32.69	$28.12	$26.42
Royalties	5.11	4.20	5.04
Hedging (gain)/loss	0.23	(0.05)	—
Operating costs	6.92	6.24	6.08
Netback	$20.43	$17.73	$15.30

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

Midstream

2003 Compared with 2002

Total midstream earnings increased by $24 million (15 percent) to $185 million in 2003 from $161 million in 2002.

Upgrading Earnings Summary

		Year ended December 31		
		2003	2002	2001
		($ millions, except where indicated)		
Gross margin		$ 313	$ 246	$ 428
Operating costs		205	154	192
Other expenses (recoveries)		(4)	(6)	(12)
DD&A		20	18	17
Income taxes		21	26	73
Earnings		$ 71	$ 54	$ 158
Upgrader throughput (1)	*(mbbls/day)*	72.5	65.4	71.7
Synthetic crude oil sales	*(mbbls/day)*	63.6	59.3	59.5
Upgrading differential	*($/bbl)*	$12.88	$10.81	$17.91
Unit margin	*($/bbl)*	$13.51	$11.05	$19.79
Unit operating cost (2)	*($/bbl)*	$ 7.77	$ 6.48	$ 7.35

(1) Throughput includes diluent returned to the field.

(2) Based on throughput.

Upgrading earnings increased by 31 percent in 2003 primarily due to:

- wider upgrading differential, which averaged $12.88/bbl in 2003 versus $10.81/bbl in 2002
- higher throughput and sales volume

partially offset by:

- higher unit operating costs, which were primarily energy related

Upgrading Earnings Variance Analysis

	($ millions)
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
Volume	18
Differential	49
Operating costs — energy related	(49)
Operating costs — non-energy related	(2)
Other	(2)
DD&A	(2)
Income taxes	5
Year ended December 31, 2003	$ 71

Infrastructure and Marketing Earnings Summary

	Year ended December 31		
	2003	2002	2001
	($ millions, except where indicated)		
Gross margin			
Pipeline	$ 66	$ 55	$86
Other infrastructure and marketing	141	147	111
	207	202	197
Other expenses	8	10	10
DD&A	21	20	17
Income taxes	64	65	72
Earnings	$114	$107	$98
Aggregate pipeline throughput *(mbbls/day)*	484	457	537

Infrastructure and marketing earnings increased by seven percent in 2003 primarily due to:

- higher heavy crude oil pipeline throughput
- higher cogeneration income

partially offset by:

- lower crude oil and natural gas commodity marketing margins

Refined Products

2003 Compared with 2002

Total refined products earnings decreased by $4 million (13 percent) to $28 million in 2003 from $32 million in 2002. Light oil refined products earnings decreased primarily due to lower fuel margins. Earnings from asphalt products operations increased reflecting strong margins and sales volumes.

Refined Products Earnings Summary

		Year ended December 31		
		2003	2002	2001
		($ millions, except where indicated)		
Gross margin				
Fuel sales		$ 71	$ 81	$ 69
Ancillary sales		28	26	27
Asphalt sales		51	45	106
		150	152	202
Operating and other expenses		70	64	59
DD&A		34	34	31
Income taxes		18	22	49
Earnings		$ 28	$ 32	$ 63
Number of fuel outlets		552	571	580
Refined products sales volume				
Light oil products	*(million litres/day)*	8.2	7.7	7.6
Light oil products per outlet	*(thousand litres/day)*	10.8	10.0	9.5
Asphalt products	*(mbbls/day)*	22.0	20.8	21.4
Refinery throughput				
Prince George refinery	*(mbbls/day)*	10.3	10.1	10.2
Lloydminster refinery	*(mbbls/day)*	25.7	22.0	23.7

Corporate

2003 Compared with 2002

Interest

Interest — net, which is total debt charges net of interest income and capitalized interest, was $73 million in 2003 compared with $104 million in 2002. Interest capitalized in 2003 was $52 million compared with $26 million in 2002 reflecting the higher aggregate capital invested in the White Rose development project in 2003. Interest income was $6 million in 2003 compared with $1 million in 2002. Total interest on short- and long-term debt in 2003 was $131 million, the same as in 2002. During 2003 interest on lower debt levels was offset by the effect of higher after swap interest rates. The impact of the interest rate risk management activities was a reduction to interest expense of $17 million in 2003. Husky's effective interest rate for 2003 after the effect of interest rate swaps was 6.32 percent compared with 5.48 percent during 2002.

Foreign Exchange

Foreign exchange gains of $215 million in 2003 comprised $315 million of gains on U.S. dollar denominated long-term debt partially offset by $73 million of cross currency swap losses and $27 million of foreign exchange losses on other monetary items.

Consolidated Income Taxes

Consolidated income taxes increased in 2003 to $474 million from $420 million in 2002 as a result of higher pre-tax earnings. Income taxes in 2003 were partially offset by a number of non-recurring benefits. On June 13, 2003, Bill C-48 received first reading in the House of Commons and thus was considered to be substantively enacted. This amendment to the Income Tax Act reduces the income tax rate on resource income by seven percent, provides for the deduction from income of crown royalties and eliminates the resource allowance deduction. The amendment will be phased in over a five-year period. The total benefit recorded was $141 million. In addition, a non-recurring benefit totalling $20 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. Both benefits reduced future income taxes. During 2002, a non-recurring benefit of $31 million was recorded with respect to federal, Alberta and British Columbia income tax rate reductions.

In 2003 current income taxes totalled $147 million and comprised $73 million with respect to the Wenchang oil field operation, $22 million of capital taxes and $52 million of Canadian income tax.

The following table shows the effect of non-recurring benefits for the periods noted:

	2003	2002
	($ millions)	
Income taxes as reported	$474	$420
Canadian federal and provincial tax changes	161	31
Pro forma income taxes	$635	$451

At December 31, 2003 and 2002, Husky's Canadian tax pools consisted of the following:

	2003	2002
	($ millions)	
Canadian exploration expense	$ 42	$ 440
Canadian development expense	1,103	967
Canadian oil and gas property expense	814	1,066
Foreign exploration and development expense	142	172
Undepreciated capital costs	2,909	2,305
Other	22	56
	$5,032	$5,006

CAPITAL RESOURCES

Operating Activities

In 2003 cash generated by operating activities was $2,572 million, an increase of $680 million from the $1,892 million recorded in 2002. The higher cash from operating activities in 2003 was primarily due to higher commodity prices and a change in non-cash working capital.

Financing Activities

In 2003 cash used in financing activities amounted to $800 million. The cash used was composed of the repayment of long-term debt of $971 million, payment of the return on capital securities of $29 million, dividends of $580 million, including a $1.00 per share special dividend and settlement of a cross currency swap of $32 million. Cash provided by financing activities in 2003 comprised $598 million issuance of long-term debt and $71 million utilization of operating lines, $51 million of proceeds from the exercise of stock options, proceeds from interest rate swaps totalling $44 million and a change of $48 million in non-cash working capital.

Husky's long-term debt balances were also reduced by $315 million during 2003 as a result of the narrowing of the exchange rate between Canadian and U.S. currencies.

Investing Activities

Cash used in investing activities amounted to $2,075 million in 2003, an increase of $486 million from the $1,589 million in 2002. Cash invested in 2003 was composed of capital expenditures of $1,905 million, acquisition of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. (''Marathon Canada'') for $809 million partially offset by $511 million of proceeds from asset sales, primarily certain Marathon Canada properties. Change in non-cash working capital and other adjustments amounted to $128 million provided by investing activities.

Capital Expenditures

The following table shows Husky's capital expenditures for the years ended December 31:

	Year ended December 31		
	2003 (1)	**2002**	**2001**
		($ millions)	
Upstream			
Exploration			
Western Canada	$ 326	$ 304	$ 236
East Coast Canada	24	41	81
International	26	9	5
	376	354	322
Development			
Western Canada	872	730	786
East Coast Canada	533	417	110
International	—	66	99
	1,405	1,213	995
	1,781	1,567	1,317
Midstream			
Upgrader	25	41	47
Infrastructure and marketing	18	17	58
	43	58	105
Refined Products	58	44	29
Corporate	23	23	22
	$1,905	$1,692	$1,473

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

Upstream Capital Expenditures

Western Canada

During 2003 capital expenditures for exploration and development in Western Canada totalled $1,198 million compared with $1,034 million during 2002.

Total development spending in Western Canada during 2003 amounted to $872 million compared with $730 million during 2002. In 2003 development capital was directed to the following areas:

- Alberta northwest plains area, $183 million for shallow natural gas drilling, completions and installation of facilities in the Boyer/Cherpeta districts.
- Lloydminster heavy oil area, $303 million for continued exploitation and optimization including work on the Bolney/Celtic thermal project, with a year-end exit rate of 10 mbbls/day. Lloydminster capital expenditures during 2002 and 2001 were $273 million and $324 million, respectively.
- East central and southern Alberta and southern Saskatchewan, $259 million primarily for in-fill drilling, facilities optimization, acquisitions and development of the Shackleton/Lacadena natural gas project in southwestern Saskatchewan. By the end of 2003, 240 net wells had been drilled and completed in the Shackleton area. Capital expenditures in the east central and southern Alberta and southern Saskatchewan areas totalled $180 million and $193 million during 2002 and 2001, respectively.
- British Columbia and Alberta foothills area, $122 million for facilities optimization and in-fill drilling at major Alberta foothills natural gas properties. Capital expenditures in the British Columbia and Alberta foothills area totalled $105 million and $115 million during 2002 and 2001, respectively.

Exploration expenditures on Husky's prospects in the Western Canada Sedimentary Basin in 2003 amounted to $326 million compared with $304 million in 2002. The primary exploration targets were natural gas prospects in the Alberta foothills as well as step-out drilling throughout Husky's properties in the Basin. In addition, pre-development spending during 2003 on the oil sands projects at Sunrise and Tucker, Alberta included in exploration capital expenditures amounted to $41 million. Capital expenditures on the oil sands projects totalled $20 million and $8 million during 2002 and 2001, respectively.

Western Canada Drilling

		Year ended December 31					
		2003		2002		2001	
		Gross	Net	Gross	Net	Gross	Net
		(wells)					
Exploration	Oil	12	11	21	20	78	76
	Gas	147	124	139	131	102	90
	Dry	22	21	15	14	36	34
		181	156	175	165	216	200
Development	Oil	520	490	497	453	594	542
	Gas	540	518	485	453	251	221
	Dry	60	57	58	55	68	63
		1,120	1,065	1,040	961	913	826
Total		1,301	1,221	1,215	1,126	1,129	1,026

East Coast Canada

Capital expenditures at Husky's White Rose oil field development offshore Newfoundland and Labrador amounted to $505 million in 2003 compared with $395 million in 2002. Capital expenditures with respect to the Terra Nova oil field amounted to $28 million in 2003 compared with $22 million in 2002.

Capital expenditures for the 2003 East Coast exploration program amounted to $24 million.

International

Exploration spending in the South China Sea amounted to $26 million in 2003 compared with $9 million in 2002. Spending in 2003 was primarily related to drilling two exploration wells and preparation for an exploration program that involved shooting an extensive seismic program in blocks 23-15, 39-05 and 40-30 followed by interpretation of the data. Drilling is expected to commence in the fourth quarter of 2004.

Midstream Capital Expenditures

Midstream capital expenditures in 2003 of $43 million were primarily for upgrader, pipeline and cogeneration plant upgrades and upgrader debottlenecking front-end engineering.

Refined Products Capital Expenditures

Refined products capital expenditures in 2003 of $58 million were primarily for marketing outlet improvements and refinery maintenance.

Corporate Capital Expenditures

Corporate capital expenditures amounted to $23 million in 2003 and 2002 and were primarily for computer hardware and software and office furniture and equipment.

Oil and Gas Reserves

One of the fundamental measures of value creation is the efficient addition of oil and gas reserves. During the three years ended December 31, 2003, Husky replaced an average of 105 percent of production on a boe basis, inclusive of acquisitions and divestitures.

During 2003, additions to proved natural gas reserves amounted to 485 bcf. Field extensions and improved recovery at Craigend, Alberta and Muskwa and Bivouac, British Columbia totalled 187 bcf, discoveries in the Alberta foothills area amounted to 114 bcf and acquisitions added 184 bcf, primarily from the acquisition of Marathon Canada, which accounted for 180 bcf. Natural gas revisions reduced reserves by 275 bcf due to a reclassification of proved natural gas reserves for Madura, Indonesia, water incursion at Ricinus in the Alberta foothills area and higher shallow gas declines at Caribou and Evergreen, Alberta. Non-core divestitures amounted to 23 bcf.

During 2003, 57 mmbbls were added to proved crude oil and NGL reserves. Additions to proved reserves from discoveries and extensions totalled 36 mmbbls primarily in the Lloydminster heavy oil area. Revisions of 9 mmbbls reflect positive technical revisions of 14 mmbbls supported by improved performance primarily in the Lloydminster area partially offset by revisions of 5 mmbbls primarily due to a reclassification of NGL reserves at Madura, Indonesia. Acquisitions of proved reserves added 12 mmbbls, 9 mmbbls of which was acquired with Marathon Canada. Non-core property divestitures were 5 mmbbls in 2003.

At December 31, 2003, 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 $5.8 billion compared with $7.2 billion at the end of 2002.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Summary of Reserves

Light Crude Oil & NGL Reserves

	Year ended December 31					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
	(mmbbls)					
Proved developed	200	177	193	171	175	153
Proved undeveloped	23	18	42	32	65	58
Total proved	223	195	235	203	240	211

Medium Crude Oil Reserves

	Year ended December 31					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
	(mmbbls)					
Proved developed	86	73	94	79	109	95
Proved undeveloped	8	7	13	12	18	16
Total proved	94	80	107	91	127	111

Heavy Crude Oil Reserves

	Year ended December 31					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
	(mmbbls)					
Proved developed	156	144	152	139	141	131
Proved undeveloped	71	66	75	68	91	87
Total proved	227	210	227	207	232	218

Natural Gas Reserves

	Year ended December 31					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
	(bcf)					
Proved developed	1,712	1,423	1,547	1,273	1,577	1,342
Proved undeveloped	347	294	548	440	389	332
Total proved	2,059	1,717	2,095	1,713	1,966	1,674

Barrels of Oil Equivalent

	Year ended December 31					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
	(mmboe)					
Proved developed	727	632	697	601	688	603
Proved undeveloped	160	140	221	185	239	216
Total proved	887	772	918	786	927	819

Reserve Life Index (1)

	Year ended December 31		
	2003	2002	2001
		(years)	
Light crude oil & NGL	8.6	9.8	14.1
Medium crude oil	6.6	6.5	7.4
Heavy crude oil	6.2	6.5	7.6
Natural gas	9.2	10.1	9.4
Barrels of oil equivalent	7.8	8.4	9.3

(1) Includes total proved reserves.

Reserve Reconciliation (1)

	Canada					International		Total	
	Western Canada				East Coast				
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(bcf)
Proved reserves, before royalties (2)									
Proved reserves at December 31, 2000	181.2	135.7	186.7	1,766.1	11.3	39.1	142.9	554.0	1,909.0
Revisions	6.5	0.3	18.9	22.5	1.2	0.2	—	27.1	22.5
Purchases	2.4	9.5	23.7	23.7	—	—	—	35.6	23.7
Sales	—	(1.8)	—	(21.1)	—	—	—	(1.8)	(21.1)
Discoveries, extensions and improved recovery	9.0	1.0	33.3	240.7	4.8	1.2	—	49.3	240.7
Production	(16.9)	(17.2)	(30.6)	(209.0)	—	(0.1)	—	(64.8)	(209.0)
Proved reserves at December 31, 2001	182.2	127.5	232.0	1,822.9	17.3	40.4	142.9	599.4	1,965.8
Revisions	(4.8)	9.7	7.0	(37.2)	—	—	—	11.9	(37.2)
Purchases	0.2	—	4.7	6.2	—	—	—	4.9	6.2
Sales	(1.8)	(14.2)	(0.4)	(19.0)	—	—	—	(16.4)	(19.0)
Discoveries, extensions and improved recovery	5.3	0.9	18.5	386.5	18.5	1.2	—	44.4	386.5
Production	(14.6)	(16.4)	(34.7)	(207.8)	(4.8)	(4.5)	—	(75.0)	(207.8)
Proved reserves at December 31, 2002	166.5	107.5	227.1	1,951.6	31.0	37.1	142.9	569.2	2,094.5
Revisions	5.0	1.3	6.4	(131.6)	0.8	(4.5)	(142.9)	9.0	(274.5)
Purchases	9.3	—	2.8	183.9	—	—	—	12.1	183.9
Sales	(0.9)	(2.5)	(1.4)	(23.1)	—	—	—	(4.8)	(23.1)
Discoveries, extensions and improved recovery	5.4	1.9	28.4	301.0	—	—	—	35.7	301.0
Production	(11.8)	(14.3)	(36.5)	(222.9)	(6.1)	(8.2)	—	(76.9)	(222.9)
Proved reserves at December 31, 2003	173.5	93.9	226.8	2,058.9	25.7	24.4	—	544.3	2,058.9
Proved developed reserves, before royalties (3)									
December 31, 2000	167.5	117.6	117.5	1,579.9	—	0.5	—	403.1	1,579.9
December 31, 2001	168.6	108.7	141.0	1,576.5	6.2	0.6	—	425.1	1,576.5
December 31, 2002	154.8	93.6	152.4	1,546.5	7.4	30.7	—	438.9	1,546.5
December 31, 2003	158.5	85.8	156.2	1,712.4	17.2	24.4	—	442.1	1,712.4
Probable reserves, before royalties (4)(5)									
December 31, 2000	72.4	35.2	105.7	434.1	202.3	5.3	18.9	420.9	453.0
December 31, 2001	72.0	36.0	105.0	405.6	213.3	4.2	18.9	430.5	424.5
December 31, 2002	70.3	24.1	152.0	383.9	201.6	4.2	18.9	452.2	402.8
December 31, 2003	61.0	13.8	171.3	381.3	182.2	7.0	66.5	435.3	447.8

(1) Husky applied for and was granted an exemption from National Instrument 51-101 ''Standards of Disclosure for Oil and Gas Activities'' to provide oil and gas reserves disclosures in accordance with the U.S. Securities and Exchange Commission guidelines and the U.S. Financial Accounting Standards Board disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101. Husky's internally generated oil and gas reserves data was audited by an independent firm of consulting engineers.

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

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

(4) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves (Canadian Oil and Gas Evaluation Handbook). The Securities and Exchange Commission in the United States does not generally permit disclosure of probable reserves to be included in filed documents due to the higher level of uncertainty associated with probable reserves.

(5) Heavy crude oil probable reserves include bitumen located in the oil sands designated regions of Alberta.

Finding and Development Costs

Western Canada (1)

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

(1) Excludes oil sands and acquisitions/divestitures.

Production Replacement

Total

	Year ended December 31			
	2001-2003	2003	2002	2001
Production *(mmboe)*	323.3	114.1	109.6	99.6
Proved reserve additions and revisions *(mmboe)*	284.0	49.1	114.5	120.4
Production replacement ratio (excluding acquisitions/divestitures) *(percent)*	88	43	104	121
Proved reserve additions and revisions (including acquisitions/divestitures) *(mmboe)*	338.6	83.2	100.9	154.5
Production replacement ratio (including acquisitions/divestitures) *(percent)*	105	73	92	155

Western Canada (1)

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

(1) 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 operating netback by the proved finding and development cost on a boe basis.

Western Canada (1)

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

(1) Excludes oil sands.

Undeveloped Land Holdings

	Year ended December 31			
	2003		2002	
	Gross	Net	Gross	Net
	(thousands of acres)			
Western Canada				
Alberta	5,508	4,852	5,416	4,907
Saskatchewan	2,057	1,911	2,098	1,986
British Columbia	713	491	314	273
Manitoba	9	8	13	13
	8,287	7,262	7,841	7,179
Northwest Territories and Arctic	527	184	463	175
Eastern Canada	2,414	2,104	2,414	2,104
Total Canada	11,228	9,550	10,718	9,458
International	4,464	2,066	4,464	2,066
Total	15,692	11,616	15,182	11,524

LIQUIDITY

Sources of Capital

As at December 31, 2003 Husky's outstanding long-term debt totalled $1,698 million, including amounts due within one year, compared with $2,385 million at December 31, 2002.

At December 31, 2003 Husky had no funds drawn under its $830 million revolving syndicated credit facility. Interest rates under 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. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than three times and a consolidated net worth of at least $3.6 billion.

At December 31, 2003 Husky had no funds drawn under its $100 million credit facility. The terms of this facility are substantially the same as the syndicated credit facility.

At December 31, 2003 the Company had drawn $71 million and utilized in support of letters of credit $18 million of its $195 million in short-term borrowing 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. In addition, Husky utilized $88 million under dedicated letter of credit facilities.

The Company has an agreement to sell up to $250 million of net trade receivables on a revolving basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, to be paid on an ongoing basis. As at December 31, 2003, $250 million of net trade receivables had been sold under this agreement. The arrangement matures on January 31, 2009.

The Company believes that, based on its current forecast for commodity prices for 2004, its 2004 capital program of $2.1 billion and non-cancellable cash contractual obligations and commitments will be funded by operating activities and, to the extent required, available credit facilities. In the event of significantly lower cash flow, the Company would be able to defer certain of its capital spending programs without penalty.

The Company declared dividends that aggregated $1.38 per share ($580 million) in 2003 including a special dividend of $1.00 per share. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of $0.10 ($0.40 annually) per common share. 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.

Cash and cash equivalents at December 31, 2003 totalled $3 million compared with $306 million at the beginning of the year.

Financial Ratios

	Year ended December 31		
	2003	2002	2001
Cash flow — operating activities *($ millions)*	$ 2,572	$ 1,892	$ 1,930
— financing activities *($ millions)*	$ (800)	$ 3	$ (423)
— investing activities *($ millions)*	$ (2,075)	$ (1,589)	$ (1,507)
Debt to capital employed *(percent)*	23.1	31.8	32.8
Debt to cash flow from operations *(times)*	0.7	1.1	1.1
Corporate reinvestment ratio (1)	0.9	0.8	0.8

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

Credit Ratings

Husky receives debt ratings from three major rating agencies. In determining Husky's debt rating the agencies evaluate several factors including, but not limited to, the industry Husky operates in, volatility of the industry, the geographical and business diversity and quality of the Company's asset base, near- and long-term production growth opportunities, capital allocation and cost structure issues, capital structure and character of oil and gas reserves. There are debt rating features in Husky's debt covenants that cause a change in interest rates in certain debt facilities and may cause the issuance of letters of credit pursuant to the terms of certain commercial contracts. In addition the Company's

debt ratings could affect the ability of the Company to secure new or additional credit facilities if the rating falls below investment grade.

At December 31, 2003 Husky had the following credit ratings:

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

Capital Requirements

Husky plans to invest capital in the following segments in 2004:

	Year ended December 31 2004 Estimate ($ millions)
Upstream	
Western Canada	$1,150
East Coast Canada	585
International	65
	1,800
Midstream	100
Refined Products	150
Corporate	30
	$2,080

In order to retain undeveloped acreage Husky is required to drill wells within a certain time frame otherwise the acreage is relinquished. In order to maintain its undeveloped acreage at current retention rates over the period 2004 to 2007, Husky estimates drilling expenditures of approximately $75 million in 2004, $65 million in 2005 and $45 million during both 2006 and 2007.

Contractual Obligations and Commercial Commitments

In the normal course of business Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations

	Total	Payments Due by Period 2004-2006	2007-2008	Thereafter
		($ millions)		
Long-term debt	$1,698	$ 545	$146	$1,007
Capital securities	291	—	—	291
Operating leases	514	194	145	175
Firm transportation agreements	1,788	679	369	740
Unconditional purchase obligations	915	776	124	15
Exploration lease agreements	497	167	97	233
Engineering and construction commitments	597	597	—	—
	$6,300	$2,958	$881	$2,461

Investment Canada Undertakings

In respect of the acquisition of Marathon Canada, Husky confirmed certain undertakings to the Minister Responsible for the Investment Canada Act. The undertakings included capital expenditures on the purchased and retained Marathon Canada lands amounting to $65 million, spending on community activities amounting to $1.35 million and environmental expenditures of $40 million, all to occur in 2004.

Asset Retirement Obligations

The above table does not include asset retirement obligations. The Company currently includes such obligations in the amortizing base of its oil and gas properties. Effective January 1, 2004 with the adoption of the Canadian Institute of Chartered Accountants (''CICA'') section 3110, ''Asset Retirement Obligations'', the Company will record a separate liability for the fair value of its asset retirement obligations. See note 20 to the Consolidated Financial Statements.

Post-retirement Benefit Obligations

The above table does not include post-retirement obligations. Husky has a defined contribution pension plan and a post-retirement health and dental care plan for its employees. In addition Husky has a defined benefit pension plan for approximately 230 employees. In 1991 admittance to the defined benefit pension plan ended after the majority of members transferred to the newly created defined contribution pension plan.

Other Obligations

Husky is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

Off Balance Sheet Arrangements

Husky does not currently utilize any off balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions or for any other purpose.

TRANSACTIONS WITH RELATED PARTIES AND MAJOR CUSTOMERS

Husky, in the ordinary course of business, entered into a lease for an eight-year term effective September 1, 2000 with Western Canadian Place Ltd. The terms of the lease provide for the lease of office space, management services and operating costs at commercial rates. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. During 2003 Husky paid approximately $17 million for office space in Western Canadian Place.

Husky did not have any customers that constituted more than five percent of total sales and operating revenues during 2003.

FINANCIAL AND DERIVATIVE INSTRUMENTS

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to the section ''Business Environment''. Husky, from time to time, uses derivative instruments to manage its exposure to these risks.

Commodity Price Risk Management

Husky uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

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

Natural Gas

The 2003 natural gas hedging program was in effect from April 2003 to December 2003. During that period Husky received net payments totalling $24 million on these contracts.

At December 31, 2003 Husky had natural gas swap agreements in place to hedge 2004 production. The contracts were as follows:

Natural Gas Hedges

	Notional Volumes	Term	Price	Unrecognized Gain/(Loss)
	(mmcf/day)			($ millions)
NYMEX fixed price	70	February 2004	U.S. $6.69/mmbtu	$ 1
	70	March 2004	U.S. $6.69/mmbtu	2
	20	April 2004	U.S. $6.38/mmbtu	1
				$ 4

Crude Oil

Crude oil hedges on 27.6 mmbbls were in effect from January to December 2003. During that period Husky recorded net payments totalling $36 million on these contracts.

Husky had a put option contract in effect from July to December 2003 on 3.7 mmbbls of crude oil with a strike price of U.S. $27/bbl. The contract was a full-term settlement contract. Husky paid $8 million for the contract which was charged to earnings over the contract period.

At December 31, 2003 Husky had crude oil swap agreements in place to hedge 2004 production. The contracts were as follows:

Crude Oil Hedges

	Notional Volumes	Term	Price	Unrecognized Gain/(Loss)
	(mbbls/day)			($ millions)
NYMEX fixed price	85	Jan. to Dec. 2004	U.S. $27.46/bbl	$(109)

Power Consumption

At December 31, 2003 Husky had hedged power consumption as follows:

Power Consumption Hedges

	Notional Volumes	Term	Price	Unrecognized Gain/(Loss)
	(MW)			($ millions)
Fixed price purchase	20.0	Jan. to Dec. 2004	$46.25/MWh	$ 1
	17.5	Jan. to Dec. 2004	$47.25/MWh	1
				$ 2

Foreign Currency Risk Management

At December 31, 2003, the Company had the following cross currency debt swaps in place:

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

At December 31, 2003 the cost of a U.S. dollar in Canadian currency was $1.2924.

In 2003 the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $73 million.

Interest Rate Risk Management

In 2003 the interest rate risk management activities resulted in a decrease to interest expense of $17 million.

The cross currency swaps resulted in an addition to interest expense of $13 million in 2003.

Husky has an interest rate swap on $200 million of long-term debt effective February 8, 2002 whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During 2003 this swap resulted in an offset to interest expense amounting to $4 million.

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

Husky had three interest rate swaps that were unwound in 2003. During 2003, the impact of these three swaps before they were unwound was an offset to interest expense of $6 million. The amortization of the swap terminations resulted in an additional $8 million offset to interest expense.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Husky's financial statements have been prepared in accordance with generally accepted accounting principles. The significant accounting policies used by Husky are disclosed in note 3 to the Consolidated Financial Statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such accounting policies and 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. Husky's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

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

Proved Oil and Gas Reserves

Proved oil and gas reserves, as defined by the U.S. Securities and Exchange Commission Regulation S-X Rule 4-10, 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, i.e., prices and costs as of the date the estimate is made.

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 oil and gas reserve 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 and estimated future development costs less estimated salvage values 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 would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would 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.

Impairment of Long-lived Assets

The Company is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

Fair Value of Derivative Instruments

Periodically Husky utilizes financial derivatives to manage market risk. The purpose of the hedge is to provide an element of stability to Husky's cash flow in a volatile environment. Husky discloses the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 Husky will adopt CICA Accounting Guideline 13, ''Hedging Relationships'' (''AcG-13''). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the Financial Accounting Standards Board (''FASB'') Statement No. 133, ''Accounting for Derivative Instruments and Hedging Activities'' (''FAS 133''). Refer to the description of FAS 133 in note 20 to the Consolidated Financial Statements.

The estimation of the fair value of certain hedging derivatives requires considerable judgement. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and, which when compared with Husky's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation. The FASB has established the Derivative Implementation Group task force, which, on an ongoing basis, considers issues arising from interpretation of these accounting rules. The potential exists that the task force may promulgate interpretations that differ from those of the Company. In this event the Company's policy would be modified.

Asset Retirement Obligations

Effective January 1, 2004 the Company will change its accounting policy with respect to accounting for asset retirement obligations. CICA section 3110, essentially the same as FASB's Statement No. 143, ''Accounting for Asset Retirement Obligations'' (''FAS 143''), requires the fair value of asset retirement obligations to be recorded when they are incurred rather than merely accumulated or accrued over the useful life of the respective asset.

The Company, under the current policy, is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated 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, the actual income tax liability may differ significantly from that estimated and recorded by management.

Business Combinations

Over recent years Husky has grown considerably through combining with other businesses. Husky acquired Marathon Canada in 2003. This transaction was accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily relies on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described above under the caption ''Proved Oil and Gas Reserves'' but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition this

methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

Goodwill

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise the determination of goodwill is also imprecise. In accordance with the recent issuance of FASB Statement No. 142 and CICA section 3062, ''Goodwill and Other Intangible Assets'', goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires Husky to determine the fair value of its assets and liabilities. Such a process involves considerable judgement.

NEW ACCOUNTING STANDARDS

Asset Retirement Obligations

In June 2001 the FASB issued FAS 143, ''Accounting for Asset Retirement Obligations''. FAS 143 was effective January 1, 2003 for U.S. reporting purposes. The Canadian version of FAS 143, CICA section 3110, which is essentially the same, is effective January 1, 2004. These new methods for accounting for asset retirement obligations require 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 CICA section 3110, the Company will adjust its existing future removal and site restoration liability retroactively with restatement.

The Company has estimated that the cumulative effect will be an increase of the future removal and site restoration liability of $129 million, an increase of related net property, plant and equipment of $164 million, an increase to the future income tax liability of $13 million and an increase in retained earnings of $22 million.

Accounting for Derivative Instruments and Hedging Activities

In June 1998 the FASB issued FAS 133, ''Accounting for Derivative Instruments and Hedging Activities''. This was followed in June 2000 when the FASB promulgated FAS 138, which amended FAS 133 and FAS 149, a further modification that was effective for contracts entered into or modified after June 30, 2003. In Canada the Accounting Standards Board (''AcSB'') intends to bring Canadian accounting standards into line with those in the U.S. by a two-stage approach. The first stage is an amendment to AcG-13, ''Hedging Relationships'', which is effective January 1, 2004 and establishes criteria to be satisfied before hedge accounting may be applied. The second stage comprises three exposure drafts that were issued on March 31, 2003. The culmination of stage two is expected to complete the harmonization of the Canadian accounting for derivatives, for all intents and purposes, with U.S. GAAP.

These accounting standards require that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded on the balance sheet as either an asset or liability measured at fair value. These standards further establish that changes in the fair value be recognized currently in earnings unless the arrangement can meet the ''effective hedge'' criteria.

Stock-based Compensation Plans

In October 1995 the FASB issued Statement No. 123, ''Accounting for Stock-based Compensation Plans'' (''FAS 123''), which established a fair value method of accounting for stock-based compensation and required companies that continued to account for stock-based compensation in accordance with the ''intrinsic method'' to provide a pro forma disclosure that reflects the difference between the two methods. In January 2003 the FASB issued FAS 148, an amendment to FAS 123, which provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. The FASB plans to issue another exposure draft in the first quarter of 2004 and issue the final statement in the second quarter of 2004. Effective January 1, 2004 CICA section 3870, ''Stock-based Compensation and Other Stock-based Payments'', will require all public companies to expense all stock-based compensation. This standard provides for the retroactive adoption of fair value accounting effective January 1, 2004. After January 1, 2004 the fair value of stock-based compensation will be recognized as an expense in the financial statements.

Oil and Gas Full Cost Accounting

In July 2003 the AcSB issued Accounting Guideline 16, ''Oil and Gas Accounting — Full Cost'' (''AcG-16''), replacing AcG-5. AcG-16 provides for methodology consistent with CICA section 3063, ''Impairment of Long-lived Assets'', CICA section 3475, ''Disposal of Long-lived Assets and Discontinued Operations'' and FASB Statement No. 144, ''Accounting for the Impairment and Disposal of Long-lived Assets''.

The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and measure the impairment amount as the difference between the carrying amount and the fair value. In addition, discontinued operations disclosure will be required upon the disposition of a component or cost centre of the entity rather than an entire business segment.

Quarterly Financial Summary

	2003				2002			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
	($ millions, except where indicated)							
Sales and operating revenues, net of royalties	$ 1,800	$ 1,871	$ 1,769	$ 2,218	$ 1,697	$ 1,669	$ 1,659	$ 1,359
Net earnings	$ 245	$ 243	$ 427	$ 406	$ 242	$ 173	$ 263	$ 126
Earnings per share								
Basic	$ 0.62	$ 0.55	$ 1.06	$ 1.01	$ 0.57	$ 0.38	$ 0.64	$ 0.29
Diluted	$ 0.62	$ 0.54	$ 1.05	$ 1.00	$ 0.57	$ 0.38	$ 0.64	$ 0.29
Cash flow from operations	$ 568	$ 604	$ 540	$ 747	$ 635	$ 590	$ 498	$ 373
Share price								
High	$ 23.95	$ 20.95	$ 18.14	$ 17.49	$ 17.20	$ 17.00	$ 17.98	$ 17.80
Low	$ 20.40	$ 17.35	$ 16.15	$ 16.03	$ 15.43	$ 14.00	$ 15.85	$ 14.20
Close (end of period)	$ 23.47	$ 20.50	$ 17.50	$ 16.93	$ 16.47	$ 16.70	$ 16.66	$ 17.10
Shares traded *(thousands)*	22,171	35,453	24,858	18,371	20,478	30,620	31,159	34,383
Dividends declared per share	$ 0.10	$ 1.10	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09
Number of weighted average common shares outstanding *(thousands)*								
Basic	421,702	419,729	418,539	418,163	417,748	417,497	417,393	416,939
Diluted	423,830	422,010	420,331	419,985	419,567	419,136	419,558	418,951

RESULTS OF OPERATIONS FOR 2002 COMPARED WITH 2001

The 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 evident in the infrastructure and marketing segment with respect to natural gas marketing revenues.

Net earnings in 2002 were $804 million compared with $654 million in 2001. The increase of $150 million was attributable to the following:

Upstream — increase of $206 million

- higher realized crude oil prices and production
- lower natural gas royalties

partially offset by:

- lower prices for natural gas
- higher operating costs and DD&A
- higher income taxes

Midstream — decrease of $95 million

- narrower upgrading differential
- lower pipeline throughput

partially offset by:

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

Refined Products — decrease of $31 million

- lower asphalt product margins

partially offset by:

- improved gasoline and distillate margins
- lower income taxes

Corporate — increase of $70 million

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

partially offset by:

- higher intersegment profit eliminations

FORWARD-LOOKING STATEMENTS

Cautionary Statement for the Purposes of the 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995

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

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

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

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

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 Securities 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.

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.

Exhibit 4

Certification required by Rule 13a-14(a) or 15d-14
of the Securities Exchange Act of 1934

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 issuer as of, and for, the periods presented in this annual report;

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

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ John C. S. Lau
John C. S. Lau
President & Chief Executive Officer

Date: March 18, 2004

Exhibit 5

Certification required by Rule 13a-14(a) or 15d-14
of the Securities Exchange Act of 1934

CERTIFICATIONS

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 issuer as of, and for, the periods presented in this annual report;

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

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

/s/ NEIL D. MCGEE
Neil D. McGee
Vice President & Chief Financial Officer

Date: March 18, 2004

Exhibit 6

Certification required by Rule 13a-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code

Certification

In connection with the annual report of Husky Energy Inc. (the ''Company'') on Form 40-F for the fiscal year ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the ''Report''), I, John C. S. Lau, President & Chief Executive Officer of the Company, 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.

/s/ John C. S. Lau

John C. S. Lau
President & Chief Executive Officer

Date: March 18, 2004

Exhibit 7

Certification required by Rule 13a-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code

Certification

In connection with the annual report of Husky Energy Inc. (the ''Company'') on Form 40-F for the fiscal year ending December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the ''Report''), I, Neil D. McGee, Vice-President and Chief Financial Officer of the Company, 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.

/s/ NEIL D. MCGEE

Neil D. McGee
Vice-President & Chief Financial Officer

Date: March 18, 2004

Exhibit 8

CONSENT OF INDEPENDENT CHARTERED ACCOUNTANTS

The Board of Directors
Husky Energy Inc.

We consent to the use of our report dated February 2, 2004 included in this annual report on Form 40-F to be filed with United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 19934, 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).

/s/ KPMG LLP
Chartered Accountants

Calgary, Canada

March 18, 2004

Exhibit 9

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, 2003 (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, and the Company's registration statement on Form F-9 (File No. 333-89714). We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2003 dated March 18, 2004 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 18, 2004