Document A
Form 40-F

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2005

Husky Energy Inc.

Annual Information Form

For the Year Ended December 31, 2005

March 14, 2006

TABLE OF CONTENTS

	Page
Exchange Rate Information	2
Disclosure Exemption Under National Instrument 51-101	2
Corporate Structure	
Husky Energy Inc.	3
Intercorporate Relationships	4
General Development of Husky	
Three Year History of Husky	4
Business Environment Trends	5
Description of Husky's Business	
General	6
Social and Environmental Policy	7
Risk Factors	7
Upstream Operations — Disclosures for Oil and Gas Activities	9
Disclosure about Oil and Gas Producing Activities — FAS 69	24
Independent Engineer's Audit Opinion	30
Report on Reserves Data by Qualified Reserves Evaluator	31
Report of Management and Directors on Reserves Data and Other Information	32
Description of Major Properties and Facilities	34
Distribution of Oil and Gas Production	49
Midstream Operations	50
Refined Products	53
Human Resources	58
Dividends	58
Description of Capital Structure	58
Market for Securities	60
Directors and Officers	61
Audit Committee	66
Legal Proceedings	67
Interest of Management and Others in Material Transactions	67
Transfer Agent and Registrars	67
Interests of Experts	67
Additional Information	67
Abbreviations and Glossary of Terms	68
Special Note Regarding Forward-looking Statements	73
Schedule ''A'' Audit Committee Charter	75

Unless otherwise indicated, all financial information is in accordance with accounting principles generally accepted in Canada. 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. A boe conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Refer to page 73 ''Special Note Regarding Forward-Looking Statements''.

EXCHANGE RATE INFORMATION

Except where otherwise indicated, all dollar amounts stated in this Annual Information Form (''AIF'') 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		
	2005	2004	2003
Year end	1.166	1.203	1.292
Low	1.151	1.178	1.292
High	1.210	1.397	1.575
Average	1.211	1.302	1.386

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.

DISCLOSURE OF 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, we applied for and were 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 us to substitute disclosures required by and consistent with those of the Securities and Exchange Commission of the United States (''SEC'') and the Financial Accounting Standards Board in the United States (''FASB'') 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 our oil and gas activities in this AIF 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, .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 AIF 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 determined in accordance with the Canadian Oil and Gas Evaluation Handbook (''COGEH'') definitions. There were no material differences between the oil and gas reserves determined using the SEC definitions and the COGEH 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 (''constant prices''). 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. In establishing the constant prices for bitumen NI 51-101 provides for a different interpretation of the phrase ''price will be the posted price of oil and the spot price of gas, after historical adjustments for transportation, gravity and other factors''. On January 20, 2005 the Canadian Securities Administrators issued Staff Notice 51-315 ''Guidance Regarding the Determination of Constant Prices for Bitumen Reserves under NI 51-101 ''Standards of Disclosure for Oil and Gas Activities''. Bitumen is very heavy crude oil that is 10 degrees

API and lower. This guidance stipulates that for establishing the constant prices for bitumen companies should use the posted price for WTI and apply the average annual adjustment for transportation, gravity and other factors that create the difference in price between WTI and bitumen. This method was developed primarily in response to the fluctuations in bitumen prices that, for various reasons, tend to experience the lowest prices at the end of the calendar year. Under the FASB/SEC rules the determination of constant price for bitumen does not permit the use of annual average differentials between WTI and bitumen. These rules require the differentials prevailing on the last day of the period to be used to calculate the constant price. As a result on December 31, 2004 the price for bitumen as established under the FASB/SEC formula was lower than the price established under NI 51-101. There is no difference in determining the constant prices for crude oil classified as heavy oil, lighter than 10 degrees API and up to and including 20 degrees API, under NI 51-101 and FASB/SEC although heavy oil experiences the same pricing patterns as bitumen.

Husky believes that its reserves evaluators are qualified and that it has a well established reserves evaluation process that is at least as rigorous as would be the case were we to rely upon independent reserves evaluators. Husky has adopted written evaluation practices and procedures using the COGEH modified to the extent necessary to reflect the definitions and standards under SEC disclosure requirements. In addition, Husky engages a firm of independent qualified reserves evaluators to conduct an audit of the reserves estimates and respective present worth value of the reserves as at December 31, 2005. They conducted their audit in accordance with the standards described in the COGEH and the auditing standards generally accepted in the United States.

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 reporting companies not to approach the SEC rules and regulations as merely a blank form but encourages them to provide such additional information that is necessary to further an investor's understanding of their business.

In either jurisdiction, information to further an investor's understanding is specifically encouraged to be included in Management's Discussion and Analysis (''MD&A''). The MD&A is intended to be a narrative explanation describing the Company, both its history and prospects, as perceived by management. The readers of the AIF are encouraged to also read the Company's MD&A, which is filed, in accordance with the requirements of the Canadian Securities Administrators, on the System for Electronic Data Analysis and Retrieval (''SEDAR''). Documents filed on SEDAR may be accessed online at www.sedar.com. This AIF, together with the MD&A and the Company's Audited Consolidated Financial Statements, are included in the FORM 40-F which is filed in accordance with the Securities and Exchange Commission (United States) on the Electronic Data Gathering Analysis and Retrieval (''EDGAR'') system, which may be accessed online at www.sec.gov.

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 security holders of Renaissance and Husky Oil exchanged their securities for securities of Husky Energy. Under the Arrangement, Husky Energy acquired 100 percent 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'', ''we'', ''our'', ''us'', and ''the Company'', mean Husky Energy Inc. 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 percent owned.

Name	Jurisdiction
Subsidiaries of Husky Energy Inc.	
Husky Oil Operations Limited	Nova Scotia
Subsidiaries of Husky Oil Operations Limited	
Husky Oil Limited	Nova Scotia
Husky Energy Marketing Inc.	Alberta
Husky (U.S.A.) Inc.	Delaware
HOI Resources Co.	Nova Scotia
Husky Energy International Sulphur Corporation	Alberta
Canterra Resources Canada Ltd. (formerly 147212 Canada Ltd.)	Canada
Subsidiaries of Husky (U.S.A.) Inc.	
Husky Gas Marketing Inc.	Delaware
Subsidiaries of HOI Resources Co.	
Husky Energy International Corporation	British Columbia
Subsidiaries of Husky Energy International Corporation	
Husky Oil China Ltd.	Alberta
Husky Oil (Madura) Ltd.	British Virgin Islands
Husky Oil Overseas Ltd.	Alberta

GENERAL DEVELOPMENT OF HUSKY

Three Year History

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 northeastern British Columbia. The acquisition added approximately 39.8 mmboe of gross proved reserves, of which 75 percent 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. CNOOC has the right to participate up to a 51 percent interest in any subsequent development.

In November 2003, we 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.

On June 18, 2004 Husky issued U.S. $300 million of 6.15 percent notes due June 15, 2019. The notes were priced to yield 6.194 percent and are redeemable at the option of the Company at any time subject to a make-whole provision. The notes are unsecured and unsubordinated and rank equally with all its other unsecured and unsubordinated indebtedness.

In August 2004 Husky filed a base shelf prospectus that permits issue of up to U.S. $1 billion of debt securities or the equivalent in other currencies during the 25 months that the prospectus is in effect.

Effective July 15, 2004, Husky acquired Temple Exploration Inc. for a cash purchase of $101.5 million plus the assumption of $13.5 million working capital deficit. The acquisition added 21.1 bcf of natural gas and 1.4 million barrels of natural gas liquids to proved reserves as well as undeveloped land.

On August 16, 2004 we signed a production sharing agreement with the CNOOC for the 3,900 square kilometre 29/26 block in the South China Sea. The agreement requires us to drill one exploration well with the option to drill two

additional exploration wells before 2011. CNOOC has the right to participate in subsequent development up to 51 percent.

On October 26, 2004 we announced an agreement to acquire our co-venturer's interest in the Madura Strait production sharing agreement in Indonesia. Husky now holds a 100 percent interest in the 2,794 square kilometre exploration block, which contains two discoveries with commercial quantities of recoverable natural gas and natural gas liquids.

In November 2004, Husky acquired three exploration licenses in the Jeanne d'Arc Basin offshore Newfoundland. We acquired a 50 percent working interest in 225,100 acres, a 100 percent working interest in 128,800 acres and a 100 percent working interest in 208,200 acres. All three parcels are near Husky's White Rose oilfield currently under development.

In September 2005, Husky announced that its Prince George refinery was now capable of producing gasoline that meets the Government of Canada's new environmental specifications thereby completing the first of two phases of a ''Clean Fuel'' refinery modification project. Completion of the second phase in 2006 will enable the refinery to produce diesel fuel in compliance with the Federal Government's environmental specifications.

On November 12, 2005 first oil was produced at the White Rose oilfield offshore Newfoundland. Husky holds a 72.5 percent interest in White Rose, which is expected to reach plateau production of 100 mbbls/day (72.5 mbbls/day Husky working interest) by mid 2006. Production from White Rose is 31 degrees API light crude oil and will supply markets both in Canada and the United States.

Subsequent Event

In January 2006, Husky acquired two additional Exploration Licences (''EL'') in the Jeanne d'Arc Basin of the Grand Banks Region offshore Newfoundland. Husky holds 100 percent working interest in the 33,320 acre EL 1094 and the 5,260 acre EL 1096. Husky has committed to spend a total of $37 million evaluating the prospects of these ELs.

On February 1, 2006 Husky redeemed its 8.45 percent senior secured bonds for U.S. $85 million.

Events Expected to Occur During 2006

Husky's in-situ oil sands project at Tucker, Alberta is expected to commence and ramp up to a plateau production of approximately 30 mbbls/day within a three to six month period. In addition Husky expects to commence front end engineering and design with respect to the extraction process for the first phase of the Sunrise in-situ oil sands project in 2006 as well as develop alternatives for upgrading and marketing. The extraction plans for Sunrise were approved by the Alberta Energy and Utilities Board in December 2005. Husky holds 100 percent working interest in both oil sands projects.

Husky expects construction of its 130 million litre per year ethanol plant at Lloydminster, Saskatchewan to be completed by mid 2006 and its second 130 million litre per year ethanol plant at Minnedosa, Manitoba to be well on its way to a scheduled mid 2007 completion date.

Business Environment Trends

There are a number of trends that are developing, which may have both long and short-term effects on the oil and gas industry in Canada. Conventional production of crude oil in the Western Canada Sedimentary Basin (''WCSB'') has been in decline since 2000 and will, according to industry forecasts[(1)], continue to decline. Since 2000 increased crude oil production from the WCSB has come from mining and in-situ production of bitumen and heavy crude oils. Non-conventional production of crude oil is forecast[(1)] to increase overall crude oil production from the WCSB beyond current production levels. Natural gas discoveries in the WCSB have, in the past few years, been made in smaller reservoirs. Natural gas exploration efforts in the WCSB are focused on the traditionally less accessible areas in the overthrust belt along the eastern slope of the Rocky Mountains, in the Northwest Territories, offshore the east coast of Canada, smaller shallow gas deposits and coal bed methane.

The trend of volatile commodity prices continues and is expected to continue. Natural gas prices are sensitive to regional supply/demand imbalances, regional industrial activity levels, weather patterns and access to cheaper sources

(1) ''Canadian Crude Oil Production and Supply forecast'', July 2004, Canadian Association of Petroleum Producers ''Oil Sands Technology Roadmap'', January 30, 2004, Alberta Chamber of Resources.

of energy. Oil prices are dependent on the world economy and stable supply. As a result of numerous supply disruptions and increased demand from China and India oil prices have remained historically high.

DESCRIPTION OF HUSKY'S BUSINESS

General

Husky is a publicly held integrated energy and energy related company headquartered in Calgary, Alberta. Our 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 with reserves classified as light (30 degrees API and lighter), medium (between 20 degrees and 30 degrees API), heavy (20 degrees and heavier but lighter than 10 degrees API) and bitumen (10 degrees API and heavier) crude oil, natural gas liquids, natural gas and sulphur. As operator of the majority of its properties Husky exercises a high degree of control in its upstream operations. We have production, gathering and processing facilities throughout the WCSB. 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.

Reserves and Land Position

At December 31, 2005, our gross proved oil and gas reserves totalled 985 mmboe comprised of 273 mmbbls of light crude oil and NGL, 91 mmbbls of medium crude oil, 291 mmbbls of heavy crude oil, 48 mmbbls of bitumen and 2.1 bcf of natural gas. At December 31, 2005, our gross proved plus probable oil and gas reserves totalled 2,260 mmboe comprised of 462 mmbbls of light crude oil and NGL, 105 mmbbls of medium crude oil, 291 mmbbls of heavy crude oil, 951 mmbbls of bitumen and 2.7 bcf of natural gas. Our undeveloped landholdings in the Western Canada Sedimentary Basin totalled 7.1 million gross acres or 40 percent of our total gross undeveloped land holdings at December 31, 2005.

Properties

In the foothills deep basin areas in Alberta, we operate the Ram River gas plant and have interests in properties that supply this plant including: Blackstone, Ricinus, Limestone, Clearwater, Benjamin, Brown Creek and Stolberg. We also have an interest in the Caroline gas plant and field. Further north we have 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 northeastern British Columbia, we hold natural gas interests in the Sikanni and Federal area as well as Boundary Lake.

In the plains region of northwest Alberta, we operate the Rainbow Lake Plant, miscible floods and properties in surrounding areas. We have interests in the Peace River Arch, Boyer, Sloat Creek, Marten Hills, Cherpeta and Simons Lake areas. In the east central region of Alberta, we have property holdings east of Calgary and around Red Deer and Edmonton including major properties at Hussar and Provost.

In southern Alberta and Saskatchewan we have extensive property holdings around Taber and Brooks in southern Alberta and throughout southwest Saskatchewan at Shackleton/Lacadena, Cantaur, Fosterton and Carnduff.

On the east coast of Canada we hold a 12.51 percent working interest in the Terra Nova oilfield, which began producing light crude oil in January 2002, and a 72.5 percent working interest in the White Rose oilfield, which was sanctioned by the co-venturers in March 2002 and produced first oil on November 12, 2005. We also hold interests in several exploration and significant discovery licenses in the Jeanne d'Arc Basin.

We hold a 40 percent working interest in the Wenchang oilfields located offshore in the South China Sea. Production at the Wenchang oilfields began in July 2002. We also hold interests in five exploration blocks in the South China Sea with an aggregate areal extent of approximately 17,800 square kilometres and one exploration block in the East China Sea of approximately 4,800 square kilometres.

Husky also holds an interest in a production sharing contract located in the Madura strait offshore Java, Indonesia. We are currently negotiating a natural gas sales contract and, upon execution of this sales contract and acquiring an

extension of the production sharing agreement, we expect to commence field development of the BD field. We also hold a small non-operator interest in the Sirte Basin in Libya

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, for continued compliance with environmental legislation and to minimize future and current costs. Husky's environmental 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. Lower prices for crude oil and natural gas could adversely affect the value and quantity of our oil and gas reserves. Husky has significant quantities of heavier grades of crude oil reserves that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining capacity for heavy crude oil is limited. As a result, wider price differentials could have adverse effects on financial performance and condition and could reduce the value and quantities of our heavier crude oil reserves and could delay or cancel projects that involve the development of heavier crude oil resources.

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 Organization of Petroleum Exporting Countries (''OPEC''), 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.

During 2005 and to the date of this report Husky did not have any commodity price hedges in-place.

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 currently experiencing high levels of activity, which is being driven by high commodity prices. The industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production and gain access to markets. 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 ability to successfully complete development projects could be adversely affected by our inability to acquire economic supplies and services. Subsequent increases in the cost of supplies and services or delays in acquiring supplies and services could result in uneconomic projects. Husky's competitors comprise all types of energy companies, some of which have greater resources.

Husky's operations are susceptible to business interruption

Our operations are subject to various risks with respect to normal operating conditions. These risks comprise, but are not limited to, explosions, blowouts, cratering, fires, severe storms and adverse weather, all forms of marine perils, release of toxic, combustible or explosive substances all of which could cause loss of life, injury and destruction of public and Husky owned property.

The occurrence of any of the above listed events or others not listed could result in adverse financial performance and condition that may not be fully recoverable from our insurers.

Foreign exchange risk

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our 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. The majority of our expenditures are in Canadian dollars. 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. Correspondingly, 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. 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, 2005, 84 percent or $1.6 billion of our long-term debt was denominated in U.S. dollars.

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 of green house gases such as carbon dioxide at its operations, 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 the 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 its estimated oil and natural gas reserves may 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

In the tables that follow, light crude oil has an API gravity of 30 degrees or more: medium crude oil has an API gravity of above 20 degrees and less than 30 degrees: heavy crude oil has an API gravity of 20 degrees to 10 degrees API.

Production

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	64.6	31.3	17.2	48.5	16.0	0.1
Medium crude oil	31.1	31.1	—	31.1	—	—
Heavy crude oil	106.0	106.0	—	106.0	—	—
Total gross	201.7	168.4	17.2	185.6	16.0	0.1
Total net	175.7	146.0	15.1	161.1	14.5	0.1
Natural Gas *(mmcf/day)*						
Gross	680.0	680.0	—	680.0	—	—
Net	488.5	488.5	—	488.5	—	—

Production (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	66.2	32.7	13.7	46.4	19.7	0.1
Medium crude oil	35.0	35.0	—	35.0	—	—
Heavy crude oil	108.9	108.9	—	108.9	—	—
Total gross	210.1	176.6	13.7	190.3	19.7	0.1
Total net	183.9	153.0	13.2	166.2	17.6	0.1
Natural Gas *(mmcf/day)*						
Gross	689.2	689.2	—	689.2	—	—
Net	524.0	524.0	—	524.0	—	—

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *(mbbls/day)*						
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 *(mmcf/day)*						
Gross	610.6	610.6	—	610.6	—	—
Net	473.7	473.7	—	473.7	—	—

Note:

(1) 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

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
			($ millions)			
Crude Oil						
Light crude oil and NGL	1,450	686	392	1,078	369	3
Medium crude oil	493	493	—	493	—	—
Heavy crude oil	1,203	1,203	—	1,203	—	—
Total gross	3,146	2,382	392	2,774	369	3
Total net	2,713	2,020	355	2,375	335	3
Natural Gas						
Gross	2,000	2,000	—	2,000	—	—
Net	1,594	1,594	—	1,594	—	—
Processing/Transportation	61	58	3	61	—	—

Revenue (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	967	474	148	622	343	2
Medium crude oil	462	462	—	462	—	—
Heavy crude oil	757	757	—	757	—	—
Total gross	2,186	1,693	148	1,841	343	2
Total net	1,824	1,375	139	1,514	308	2
Natural Gas						
Gross	1,596	1,596	—	1,596	—	—
Net	1,248	1,248	—	1,248	—	—
Processing	48	48	—	48	—	—

	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	—	—

Sales Prices

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil and NGL	61.56	60.15	62.60	61.02	63.15	69.23
Medium crude oil	43.44	43.44	—	43.44	—	—
Heavy crude oil	31.09	31.09	—	31.09	—	—
Total crude oil and NGL	42.75	38.77	62.60	40.97	63.15	69.23
Natural Gas *($/mcf)*	7.96	7.96	—	7.96	—	—

Sales Prices (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil and NGL	48.34	49.35	47.87	49.64	47.66	57.88
Medium crude oil	36.13	36.13	—	36.13	—	—
Heavy crude oil	28.66	28.66	—	28.66	—	—
Total crude oil and NGL (before hedging)	36.07	33.85	47.87	34.90	47.66	57.88
Total crude oil and NGL (after hedging)	28.43	26.19	29.45	26.42	47.66	57.88
Natural Gas *($/mcf)*						
Before hedging	6.25	6.25	—	6.25	—	—
After hedging	6.24	6.24	—	6.24	—	—

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

Capital Expenditures

	2005						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
	($ millions)						
Property acquisition	133	133	—	133	—	—	—
Exploration	445	324	66	390	55	—	—
Development	2,152	1,550	579	2,129	14	8	1
	2,730	2,007	645	2,652	69	8	1

	2004						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
	($ millions)						
Property acquisition[1]	116	54	—	54	—	62	—
Exploration	313	271	24	295	18	—	—
Development	1,728	1,208	515	1,723	5	—	—
	2,157	1,533	539	2,072	23	62	—

Capital Expenditures (continued)

	2003						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisitions[2]	76	76	—	76	—	—	—
Exploration	324	274	24	298	26	—	—
Development	1,378	845	533	1,378	—	—	—
	1,778	1,195	557	1,752	26	—	—

Notes:

(1) Does not include the acquisition of Temple Exploration Inc.

(2) Does not include the acquisition of Marathon Canada Limited.

Oil and Gas Netbacks

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 product classification.

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	61.86	60.74	62.60	61.41	63.15	69.23
Royalties	7.22	8.66	5.91	7.67	5.93	—
Operating costs	6.88	9.86	5.14	8.16	2.92	22.73
Netback	47.76	42.22	51.55	45.58	54.30	46.50
Medium crude oil						
Sales revenue	43.67	43.67	—	43.67	—	—
Royalties	7.77	7.77	—	7.77	—	—
Operating costs	10.97	10.97	—	10.97	—	—
Net back	24.93	24.93	—	24.93	—	—
Heavy crude oil						
Sales revenue	31.22	31.22	—	31.22	—	—
Royalties	3.75	3.75	—	3.75	—	—
Operating costs	9.90	9.90	—	9.90	—	—
Netback	17.57	17.57	—	17.57	—	—
Total crude oil						
Sales revenue	42.83	38.91	62.60	41.08	63.15	69.23
Royalties	5.49	5.41	5.91	5.45	5.93	—
Operating costs	9.13	10.10	5.14	9.65	2.92	22.73
Netback	28.21	23.40	51.55	25.98	54.30	46.50
Natural Gas *($/mcf)*						
Sales revenue	8.02	8.02	—	8.02	—	—
Royalties	1.76	1.76	—	1.76	—	—
Operating costs	1.04	1.04	—	1.04	—	—
Netback	5.22	5.22	—	5.22	—	—
Equivalent Unit *($/boe)*						
Sales revenue	44.56	42.53	62.60	43.69	63.15	69.23
Royalties	7.29	7.45	5.91	7.36	5.93	—
Operating costs	8.12	8.59	5.14	8.39	2.92	22.73
Netback	29.15	26.49	51.55	27.94	54.30	46.50

Oil and Gas Netbacks (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	46.95	46.12	47.87	46.63	47.66	57.88
Royalties	5.71	7.76	1.80	6.03	4.91	—
Operating costs	5.82	8.94	3.28	7.29	2.16	16.47
Netback before hedging	35.42	29.42	42.79	33.31	40.59	41.41
Medium crude oil						
Sales revenue	36.20	36.20	—	36.20	—	—
Royalties	6.10	6.10	—	6.10	—	—
Operating costs	10.07	10.07	—	10.07	—	—
Netback before hedging	20.03	20.03	—	20.03	—	—
Heavy crude oil						
Sales revenue	28.73	28.73	—	28.73	—	—
Royalties	3.38	3.38	—	3.38	—	—
Operating costs	9.33	9.33	—	9.33	—	—
Netback before hedging	16.02	16.02	—	16.02	—	—
Total crude oil						
Sales revenue	35.72	33.48	47.87	34.50	47.66	57.88
Royalties	4.58	4.75	1.80	4.54	4.91	—
Operating costs	8.36	9.41	3.28	8.97	2.16	16.47
Netback before hedging	22.78	19.32	42.79	20.99	40.59	41.41
Netback after hedging	15.64	12.25	24.37	13.11	40.59	41.41
Natural Gas *($/mcf)*						
Sales revenue	6.25	6.25	—	6.25	—	—
Royalties	1.44	1.44	—	1.44	—	—
Operating costs	0.89	0.89	—	0.89	—	—
Netback before hedging	3.92	3.92	—	3.92	—	—
Netback after hedging	3.91	3.91	—	3.91	—	—
Equivalent Unit *($/boe)*						
Sales revenue	36.34	35.01	47.87	35.60	47.66	57.88
Royalties	5.96	6.22	1.80	6.03	4.91	—
Operating costs	7.32	7.85	3.28	7.66	2.16	16.47
Netback	23.06	20.94	42.79	21.91	40.59	41.41

Oil and Gas Netbacks (continued)

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	40.17	39.91	38.91	39.55	41.45	40.44
Royalties	4.55	7.28	0.81	4.93	3.80	—
Operating costs	5.41	9.27	3.16	7.05	1.94	15.43
Netback before hedging	30.21	23.36	34.94	27.57	35.71	25.01
Medium crude oil						
Sales revenue	31.57	31.57	—	31.57	—	—
Royalties	5.28	5.28	—	5.28	—	—
Operating costs	9.53	9.53	—	9.53	—	—
Netback before hedging	16.76	16.76	—	16.76	—	—
Heavy crude oil						
Sales revenue	25.98	25.98	—	25.98	—	—
Royalties	2.76	2.76	—	2.76	—	—
Operating costs	9.09	9.09	—	9.09	—	—
Netback before hedging	14.13	14.13	—	14.13	—	—
Total crude oil						
Sales revenue	31.70	29.52	38.91	30.53	41.45	40.44
Royalties	3.83	4.14	0.81	3.84	3.80	—
Operating costs	7.97	9.23	3.16	8.68	1.94	15.43
Netback before hedging	19.90	16.15	34.94	18.01	35.71	25.01
Netback after hedging	19.32	15.63	32.99	17.36	35.71	25.01
Natural Gas *($/mcf)*						
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	—	—
Equivalent Unit *($/boe)*						
Sales revenue	32.69	31.58	38.91	32.01	41.45	40.44
Royalties	5.11	5.48	0.81	5.21	3.80	—
Operating costs	6.92	7.56	3.16	7.30	1.94	15.43
Netback	20.66	18.54	34.94	19.50	35.71	25.01

Producing Wells

	Oil Wells		Natural Gas Wells		Total	
	Gross[1][2]	Net[1]	Gross[1][2]	Net[1]	Gross[1][2]	Net[1]
Canada						
Alberta	4,308	3,341	4,658	3,794	8,966	7,135
Saskatchewan	4,567	3,644	922	826	5,489	4,470
British Columbia	224	78	183	122	407	200
Newfoundland and Labrador	17	4	—	—	17	4
Northwest Territories	5	1	5	1	10	2
	9,121	7,068	5,768	4,743	14,889	11,811
International						
China	24	10	—	—	24	10
Libya	2	1	—	—	2	1
	26	11	—	—	26	11
As at December 31, 2005	9,147	7,079	5,768	4,743	14,915	11,822
Canada						
Alberta	4,477	3,525	4,219	3,367	8,696	6,892
Saskatchewan	4,628	3,689	763	672	5,391	4,361
British Columbia	223	78	133	74	356	152
Manitoba	1	1	—	—	1	1
Newfoundland and Labrador	10	2	—	—	10	2
Northwest Territories	1	—	2	—	3	—
	9,340	7,295	5,117	4,113	14,457	11,408
International						
China	17	8	—	—	17	8
Libya	2	1	—	—	2	1
	19	9	—	—	19	9
As at December 31, 2004	9,359	7,304	5,117	4,113	14,476	11,417

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. Producing wells were producing or capable of producing at December 31.

(2) 2005 includes 331 gross, 312 net oil wells and 566 gross, 459 net natural gas wells and 2004 includes 482 gross, 411 net oil wells and 538 gross, 337 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.

(3) The above table does not include wells in which Husky holds a royalty interest. At December 31, 2005 Husky had royalty interests in 3,679 wells of which 1,370 were oil producers and 2,309 were natural gas producers.

Landholdings

	Developed Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2005		
Western Canada		
Alberta	3,146	2,633
Saskatchewan	577	517
British Columbia	182	112
Manitoba	—	—
	3,905	3,262
Northwest Territories and Arctic	7	1
Eastern Canada	35	4
	3,947	3,267
China	17	7
Libya	7	2
	3,971	3,276
As at December 31, 2004		
Western Canada		
Alberta	3,200	2,687
Saskatchewan	567	506
British Columbia	186	110
Manitoba	—	—
	3,953	3,303
Northwest Territories and Arctic	7	1
Eastern Canada	35	4
	3,995	3,308
China	17	7
Libya	7	2
	4,019	3,317

	Undeveloped Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2005		
Western Canada		
Alberta	4,518	3,998
Saskatchewan	1,715	1,577
British Columbia	862	615
Manitoba	2	2
	7,097	6,192
Northwest Territories and Arctic	664	180
Eastern Canada	3,722	2,927
	11,483	9,299
International	6,280	3,429
	17,763	12,728

Landholdings (continued)

	Undeveloped Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2004		
Western Canada		
Alberta	4,983	4,449
Saskatchewan	1,831	1,669
British Columbia	787	544
Manitoba	7	7
	7,608	6,669
Northwest Territories and Arctic	924	254
Eastern Canada	3,154	2,104
	11,686	9,027
International	6,280	3,429
	17,966	12,456

Drilling Activity

	Year ended December 31					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Western Canada Drilling						
Exploration						
Oil	89	85	45	39	12	11
Gas	392	196	234	180	147	124
Dry	36	36	34	33	22	21
	517	317	313	252	181	156
Development						
Oil	466	433	552	499	520	490
Gas	610	551	807	740	540	518
Dry	42	39	57	53	60	57
	1,118	1,023	1,416	1,292	1,120	1,065
	1,635	1,340	1,729	1,544	1,301	1,221

Present Activities

	Exploratory		Development	
Wells Drilling[1]	Gross	Net	Gross	Net
Western Canada	12	8.1	17	14.5
East Coast	—	—	2	0.9
China	—	—	—	—
	12	8.1	19	15.4

Note:

(1) Denotes wells that were drilling at December 31, 2005.

Reserves Data and Other Oil and Gas Information

Husky's oil and gas reserves as of December 31, 2005 are based on prices and costs in effect on that date and remain constant in future periods in accordance with the Financial Accounting Standards Board and the Securities and Exchange Commission (U.S.) as prepared internally by Husky's reserves evaluation staff. 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 reserves evaluators.

Audit of Oil and Gas Reserves

McDaniel & Associates Consultants Ltd., an independent firm of qualified 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 COGEH.

Oil and Gas Reserves Data

The following table presents in summary Husky's gross and net proved developed reserves, gross and net proved undeveloped reserves and associated future net cash flows as at December 31, 2005. Future revenues, based on prices and costs in effect on that date and remain constant in future periods, are presented net of royalties. Estimated future net revenues 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.

Proved Reserves

	Crude Oil & NGL[1]		Natural Gas[1]		Future Net Cash Flows Before Tax[1][4]	
	Gross[2]	Net[2]	Gross[2]	Net[2]	0%	10%
	(mmbbls)		(bcf)		($ millions)	
Proved developed[3]	446	399	1,710	1,413	22,512	13,782
Proved undeveloped[3][5]	183	166	426	358	5,001	2,923
Proved total[3]	629	565	2,136	1,771	27,513	16,705

Notes:

(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 qualified reserves evaluators.

(2) 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.

(3) These reserve categories have the same meanings as those set out in SEC Regulation S-X.

(4) The discounted future net cash flows at December 31, 2005 were based on the year-end spot NYMEX natural gas price of U.S. $9.52/mmbtu and on a spot WTI crude oil price of U.S. $61.06/bbl.

(5) Estimated future capital expenditures required to gain access to proved undeveloped reserves as at December 31, 2005 and 2004 were as follows:

	As at December 31, 2005						
	Total	2006	2007	2008	2009	2010	Thereafter
	($ millions undiscounted)						
Western Canada	1,428	545	353	191	116	56	167
Eastern Canada	109	87	—	—	—	—	22
	1,537	632	353	191	116	56	189

	As at December 31, 2004						
	Total	2005	2006	2007	2008	2009	Thereafter
Western Canada	651	218	210	107	34	13	69
Eastern Canada	352	390	19	9	11	4	(81)
	1,003	608	229	116	45	17	(12)

(6) On December 31, 2005, the date our oil and gas reserves were evaluated, the calculated price of Lloydminster heavy crude oil was $28.57 per barrel. Our heavy crude oil reserves were economic at that price and no negative price revision resulted.

Reconciliation of Gross Proved Reserves

	Canada						International		Total	
	Western Canada					East Coast				
Proved Reserves, Before Royalties[1]	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Bitumen[2]	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(bcf)
End of 2002	166	108	227	1,952		31	37	143	569	2,095
Revisions	5	1	6	(132)		1	(5)	(143)	8	(275)
Purchases	9		3	184					12	184
Sales	(1)	(3)	(1)	(23)					(5)	(23)
Discoveries and extensions	5	2	29	300					36	300
Improved recovery	1			1					1	1
Production	(12)	(14)	(37)	(223)		(6)	(8)		(77)	(223)
End of 2003	173	94	227	2,059		26	24		544	2,059
Revisions	1	1	(114)	(23)		(1)	3		(110)	(23)
Purchases	1			23					1	23
Sales			(1)	(14)					(1)	(14)
Discoveries and extensions	7	2	32	372		24			65	372
Improved recovery	1	2	1	4		3			7	4
Production	(12)	(13)	(40)	(252)		(5)	(7)		(77)	(252)
End of 2004	171	86	105	2,169		47	20		429	2,169
Revisions	3	9	121	(65)		9	2		144	(65)
Purchases			7	3					7	3
Sales		(3)	(4)	(9)					(7)	(9)
Discoveries and extensions	4	3	27	277	48	16	1		99	277
Improved recovery	1	7		9		23			31	9
Production	(12)	(11)	(39)	(248)		(6)	(6)		(74)	(248)
End of 2005	167	91	217	2,136	48	89	17		629	2,136

Notes:

(1) 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.

(2) Bitumen is very heavy crude oil that is 10 degrees API and lower.

Gross Reserves and Production by Principal Area

Crude Oil and NGL[1]	Proved Reserves (mmbbls)	Production (mbbls/day)
Canada		
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	29	6
Foothills Deep Gas area	24	6
Ram River and Kaybob areas	7	2
Northwest Alberta Plains		
Rainbow Lake area	83	8
Peace River Arch area	10	4
East Central Alberta		
North area	2	1
South area	7	3
Provost area	29	15
Southern Alberta and Saskatchewan		
South Alberta area	25	9
South Saskatchewan area	69	17
Lloydminster Area		
Primary production	124	79
Thermal production	66	18
Oil Sands	48	—
Other[2]	—	1
	523	169
East Coast Canada		
Terra Nova	21	12
White Rose	68	5
	89	17
China		
Wenchang	17	16
	629	202

Notes:

(1) Gross crude oil and NGL reserves as at December 31, 2005 and average 2005 daily gross production of crude oil and NGL.

(2) Other is comprised primarily of royalty interests, which are not considered to be reserves.

Natural Gas[1]	Proved Reserves (bcf)	Production (mmcf/day)
Canada		
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	174	56
Foothills Deep Gas area	278	92
Ram River and Kaybob areas	249	76
Northwest Alberta Plains		
Rainbow Lake area	381	56
Peace River Arch	47	25
Northern Alberta area	246	89
East Central Alberta		
Provost area	73	22
North area	177	54
South area	197	57
Southern Alberta and Saskatchewan		
South Alberta area	52	32
South Saskatchewan area	188	58
Lloydminster Area	74	56
Other[2]	—	7
	2,136	680

Notes:

(1) Gross natural gas reserves as at December 31, 2005 and average 2005 daily gross production of natural gas.

(2) Other is comprised primarily of royalty interests, which are not considered to be reserves.

Gross Probable Oil and Gas Reserves[1]

Crude Oil & NGL

	Canada				
	Western Canada				
	Conventional	Bitumen	East Coast	International	Total
			(mmbbls)		
2005	146	903	118	13	1,180
2004	113	79	156	13	361
2003	167	79	182	7	435

Natural Gas

	Canada		
	Western Canada		
	Conventional	International	Total
	(bcf)		
2005	407	167	574
2004	388	167	555
2003	381	67	448

Barrels of Oil Equivalent

	Canada				
	Western Canada				
	Conventional	Bitumen	East Coast	International	Total
			(mmboe)		
2005	213	903	118	41	1,275
2004	177	79	156	41	453
2003	231	79	182	18	510

Notes:

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

(2) Probable bitumen reserves were based on constant prices calculated in accordance with the Canadian Securities Administrators Staff Notice 51-315 ''Guidance Regarding the Determination of Constant Prices for Bitumen Reserves under National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (the ''Staff Notice''). Bitumen reserves at December 31, 2004 remain classified as probable reserves because the pricing formula in the Staff Notice results in an economically viable price as at that date whereas 37 mmbbls of heavy oil reserves were subtracted from probable reserves due to low December 31, 2004 heavy oil prices under the constant pricing calculation applicable to heavy oil, which differed from the bitumen calculation. See ''Disclosure of Exemption under National Instrument 51-101'' for further discussion.

(3) Proved and probable bitumen reserves are included under the caption Western Canada.

(4) 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 in an exemption order granted to Husky pursuant to Part 8 of the Companion Policy to NI 51-101.

Disclosure about Oil and Gas Producing Activities — Statement of Financial Accounting Standards No. 69

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

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 our estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause our share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2005, 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

Results of Operations for Producing Activities[1][2]	Canada			International			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
	($ millions except per boe amounts)								
Oil and gas production revenue	4,085	2,866	2,917	337	310	310	4,422	3,176	3,227
Operating costs									
Lease operating expenses	925	874	794	18	17	17	943	891	811
Production taxes	56	56	41	—	—	—	56	56	41
Asset retirement obligation accretion	28	23	18	—	—	—	28	23	18
	1,009	953	853	18	17	17	1,027	970	870
Depreciation, depletion and amortization	1,102	1,018	852	42	59	66	1,144	1,077	918
Earnings before taxes	1,974	895	1,212	277	234	227	2,251	1,129	1,439
Income tax	730	349	491	106	92	91	836	441	582
Results of operations	1,244	546	721	171	142	136	1,415	688	857
Operating costs per gross boe[3]	8.39	7.66	7.30	3.06	2.25	2.04	8.12	7.32	6.92
Operating costs per net boe[4]	11.09	10.02	9.32	3.24	2.81	2.31	10.64	9.55	8.78
Amortization rate per gross boe	10.10	9.11	8.05	7.21	8.19	8.00	9.95	9.06	8.04
Amortization rate per net boe	12.45	10.97	9.51	7.96	9.13	8.81	12.19	10.85	9.46

Notes:

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

(2) Under U.S. GAAP, the depreciation, depletion and amortization for Canadian producing activities for 2005 amounted to $1,036 million (2004 — $981 million; 2003 — $772 million). Income taxes for Canadian producing activities under U.S. GAAP for 2005 amounted to $755 million (2004 — $364 million; 2003 — $511 million).

(3) Unit operating costs are field operating expenses divided by gross production.

(4) Unit operating costs include field operating costs, direct administrative expenses and production taxes divided by net production.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities[1]

	Canada	International	Total
		($ millions)	
2005			
Property acquisition			
Proved	68	—	68
Unproved	65	—	65
Exploration	390	55	445
Development	2,042	23	2,065
Capitalized interest	112	—	112
Total costs incurred	2,677	78	2,755
Less: Proved acquisitions	68	—	68
Capitalized interest	112	—	112
Finding and development costs	2,497	78	2,575
2004			
Property acquisition			
Proved	101	—	101
Unproved	91	62	153
Exploration	295	18	313
Development	1,712	4	1,716
Capitalized interest	75	—	75
Total costs incurred	2,274	84	2,358
Less: Proved acquisitions	101	—	101
Capitalized interest	75	—	75
Finding and development costs	2,098	84	2,182
2003			
Property acquisition			
Proved	541	—	541
Unproved	106	—	106
Exploration	298	26	324
Development	1,402	2	1,404
Capitalized interest	52	—	52
Total costs incurred	2,399	28	2,427
Less: Proved acquisitions	541	—	541
Capitalized interest	52	—	52
Finding and development costs	1,806	28	1,834

Notes:

(1) Development costs incurred exclude actual retirement expenditures and include asset retirement obligation incurred.

(2) Property acquisition costs related to corporate acquisitions for proved properties were $98 million.

(3) Property acquisition costs related to corporate acquisitions for unproved properties were $40 million.

(4) Property acquisition costs related to corporate acquisitions for proved properties were $517 million.

(5) Property acquisition costs related to corporate acquisitions for unproved properties were $54 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, facilities to extract, treat and gather and store oil and gas and settle the related asset retirement obligations.

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, 2005, by the year in which the costs were incurred:

Withheld Costs	Total	2005	2004	2003	Prior to 2003
		($ millions)			
Property acquisitions					
Canada	301	54	—	56	191
International	75	—	62	—	13
	376	54	62	56	204
Exploration					
Canada	417	279	96	42	—
International	37	22	13	2	—
	454	301	109	44	—
Development					
Canada	1,213	826	294	93	—
International	15	6	1	1	7
	1,228	832	295	94	7
Capitalized interest					
Canada	385	112	75	52	146
	2,443	1,299	541	246	357

Capitalized Costs Relating to Oil and Gas Producing Activities

	Canada	International	Total
		($ millions)	
2005			
Proved properties	16,195	528	16,723
Unproved properties	2,317	127	2,444
	18,512	655	19,167
Accumulated DD&A	6,729	354	7,083
Net Capitalized Costs[2]	11,783	301	12,084
2004			
Proved properties	13,624	458	14,082
Unproved properties	2,399	129	2,528
	16,023	587	16,610
Accumulated DD&A	5,722	311	6,033
Net Capitalized Costs[2]	10,301	276	10,577
2003			
Proved properties	12,017	449	12,466
Unproved properties	1,814	54	1,868
	13,831	503	14,334
Accumulated DD&A	4,718	252	4,970
Net Capitalized Costs[2]	9,113	251	9,364

Notes:

(1) Capitalized costs related to proved properties include the asset retirement obligations. The asset retirement obligations for the years presented were as follows:

	Canada	International	Total
2005	377	6	383
2004	314	6	320
2003	223	7	230

(2) The net capitalized costs for Canadian oil and gas exploration, development and producing activities under U.S. GAAP for 2005 was $11,290 million (2004 — $9,721 million, 2003 — $8,518 million). The net capitalized costs for International property oil and gas exploration, development and producing activities under U.S. GAAP for 2005 was $300 million (2004 — $274 million, 2003 — $249 million). Please refer to note 19 to the Consolidated Financial Statements for an explanation of the differences between Canadian and U.S. GAAP for oil and gas activities.

Oil and Gas Reserve Information

In Canada, our proved crude oil, natural gas liquids and natural gas reserves are located in the provinces of Alberta, Saskatchewan and British Columbia, and offshore the East Coast. Our international proved reserves are located in China and Libya.

	Canada		International		Total	
Reserves	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmbbls)	(bcf)
Net proved reserves[1][2][3][4]						
End of 2002	468	1,612	33	101	501	1,713
Revisions	19	(89)	(3)	(101)	16	(190)
Purchases	9	146	—	—	9	146
Sales	(4)	(16)	—	—	(4)	(16)
Discoveries and extensions	31	245	—	—	31	245
Improved recovery	1	1	—	—	1	1
Production	(61)	(182)	(8)	—	(69)	(182)
End of 2003	463	1,717	22	—	485	1,717
Revisions	(105)	(54)	2	—	(103)	(54)
Purchases	1	17	—	—	1	17
Sales	(1)	(12)	—	—	(1)	(12)
Discoveries and extensions	55	309		—	55	309
Improved recovery	6	3	—	—	6	3
Production	(62)	(192)	(6)	—	(68)	(192)
End of 2004	357	1,788	18	—	375	1,788
Revisions	129	(75)	2	—	131	(75)
Purchases	6	2	—	—	6	2
Sales	(7)	(7)	—	—	(7)	(7)
Discoveries and extensions	94	230	1	—	95	230
Improved recovery	29	6	—	—	29	6
Production	(59)	(173)	(5)	—	(64)	(173)
End of 2005	549	1,771	16	—	565	1,771
Net proved developed reserves,[1][2][3][4]						
End of year 2002	361	1,273	28	—	389	1,273
End of year 2003	372	1,423	23	—	395	1,423
End of year 2004	299	1,436	18	—	317	1,436
End of year 2005	327	1,413	15	—	342	1,413

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 our reserves evaluation staff. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating Husky 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 Husky's reserves.

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.

	Canada[1]			International[1]			Total[1]		
Standardized Measure	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
				($ millions)					
Future cash inflows	40,066	22,681	24,003	999	979	928	41,065	23,660	24,931
Future production and development costs	13,430	9,353	8,645	122	148	146	13,552	9,501	8,791
Future income taxes	9,000	4,871	5,696	272	266	247	9,272	5,137	5,943
Future net cash flows	17,636	8,457	9,662	605	565	535	18,241	9,022	10,197
Annual 10 percent discount factor	7,115	3,712	4,242	123	105	117	7,238	3,817	4,359
Standardized measure of discounted Future net cash flows	10,521	4,745	5,420	482	460	418	11,003	5,205	5,838

Changes in Standardized Measure

	Canada[1]			International[1]			Total[1]		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
					($ millions)				
Present value at January 1	4,745	5,420	6,347	460	418	839	5,205	5,838	7,186
Sales and transfers, net of production costs	(3,101)	(1,952)	(2,097)	(320)	(294)	(293)	(3,421)	(2,246)	(2,390)
Net change in sales and transfer prices, net of development and production costs	5,585	555	(1,379)	155	197	(376)	5,740	752	(1,755)
Extensions, discoveries and improved recovery, net of related costs	2,027	958	541	24	—	—	2,051	958	541
Revisions of quantity estimates	2,310	(1,318)	76	110	85	(97)	2,420	(1,233)	(21)
Accretion of discount	762	877	1,055	68	61	130	830	938	1,185
Sale of reserves in place	(62)	(20)	(47)	—	—	—	(62)	(20)	(47)
Purchase of reserves in place	36	45	304	—	—	—	36	45	304
Changes in timing of future net cash flows and other	826	(233)	(237)	(13)	17	(49)	813	(216)	(286)
Net change in income taxes	(2,607)	413	857	(2)	(24)	264	(2,609)	389	1,121
Net increase (decrease)	5,776	(675)	(927)	22	42	(421)	5,798	(633)	(1,348)
Present value at December 31	10,521	4,745	5,420	482	460	418	11,003	5,205	5,838

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.

The future cash flows presented 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.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2005 was based on the NYMEX year-end natural gas spot price of U.S. $9.52/mmbtu (2004 — U.S. $6.02/mmbtu; 2003 — U.S. $5.96/mmbtu) and on crude oil prices computed with reference to the year-end WTI price of U.S. $61.06/bbl (2004 — U.S. $43.36/bbl; 2003 — U.S. $32.51/bbl).

INDEPENDENT ENGINEER'S AUDIT OPINION

January 23, 2006

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

Gentlemen:

Pursuant to Husky's 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, 2005. 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 based on forecast and constant price assumptions 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/ P.A. Welch

P.A. Welch
President & Managing Director

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 reserves data as at December 31, 2005. The reserves data consists of the following:
   (a) proved oil and gas reserve quantities estimated as at December 31, 2005 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, 2005:

Location of Reserves (country or foreign geographic area)	**Discounted Future Net Cash Flows (Before Income Taxes, 10% Discount Rate)** ($ millions)
Canada	16,005
China	688
Libya	12
	16,705

We have filed the Company's oil and gas reserves disclosures in accordance with Financial Accounting Standards Board Statement No. 69 ''Disclosures about Oil and Gas Producing Activities'' 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.

Calgary, Alberta
January 19, 2006

/s/ PRESTON KRAFT P. ENG

Preston Kraft P. Eng
Manager of Reservoir Engineering

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Husky Energy Inc. (Husky) are responsible for the preparation and disclosure of information with respect to Husky'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, 2005 using constant prices and costs; and

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

Husky's 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''). Husky's Internal Qualified Reserves Evaluator is the Manager of Reservoir Engineering, who is an employee of Husky and has evaluated Husky'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 accompanies this report and will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors has:

(a) reviewed Husky'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 evaluator.

The Audit Committee of the Board of Directors has reviewed Husky'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 approved, on the recommendation of the Audit Committee:

(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.

Husky sought and was granted by the Canadian Securities Administrators an exemption from the requirement under National Instrument 51-101 ''Standards of Disclosure for Oil and Gas Disclosure'' to involve independent qualified oil and gas reserves evaluators or auditors. Notwithstanding this exemption, Husky involve independent qualified reserve auditors as part of Husky's corporate governance practices. Their involvement helps assure that Husky's internal oil and gas reserves estimates are materially correct.

In Husky's view, the reliability of its internally generated oil and gas reserves data is not materially different than would be afforded by Husky involving independent qualified reserves evaluators or independent qualified reserves auditors to evaluate or audit and review the reserves data. Husky is therefore relying on an exemption, which it sought and was granted by securities regulatory authorities, from the requirement under securities legislation to involve independent qualified reserves evaluators or independent qualified reserves auditors.

The primary factors supporting the involvement of independent qualified reserves evaluators or independent qualified reserves auditors apply when (i) their knowledge of, and experience with, a reporting issuer's reserves data are superior to that of the internal evaluators and (ii) the work of the independent qualified reserves evaluator or independent qualified reserves auditors is significantly less likely to be adversely influenced by self-interest or management of the reporting issuer than the work of internal reserves evaluation staff. In Husky's view, neither of these factors applies in Husky's circumstances.

Husky's view is based in large part on the following. Husky's reserves data were developed in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook. Husky's procedures, records and controls relating to the accumulation of source data and preparation of reserves data by Husky's internal reserves evaluation staff have been established, refined and documented over many years. Husky's internal reserves evaluation staff includes

133 individuals, including support staff, of whom 64 individuals are qualified reserves evaluators as defined in the Canadian Oil and Gas Evaluation Handbook, with an average of 8 years of relevant experience in evaluating reserves. Husky's internal reserves evaluation management personnel includes 24 individuals with an average of 12 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 14, 2006
John C. S. Lau President & Chief Executive Officer	
/s/ JAMES D. GIRGULIS	March 14, 2006
James D. Girgulis Vice President Legal & Corporate Secretary	
/s/ R. DONALD FULLERTON	March 14, 2006
R. Donald Fullerton Director	
/s/ WAYNE E. SHAW	March 14, 2006
Wayne E. Shaw Director	

Description of Major Properties and Facilities

Husky's portfolio of assets includes properties with reserves of light (30 degrees API and lighter), medium (between 20 degrees and 30 degrees API) heavy (20 degrees API and heavier but lighter than 10 degrees API) and bitumen (10 degrees API and heavier) gravity crude oil, NGL, natural gas and sulphur.

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 Canadian provinces of Saskatchewan and Alberta. Approximately 80 percent 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, Gully Lake 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. We maintain a land position of approximately 1.6 million acres in the Lloydminster area, of which approximately 70 percent is undeveloped.

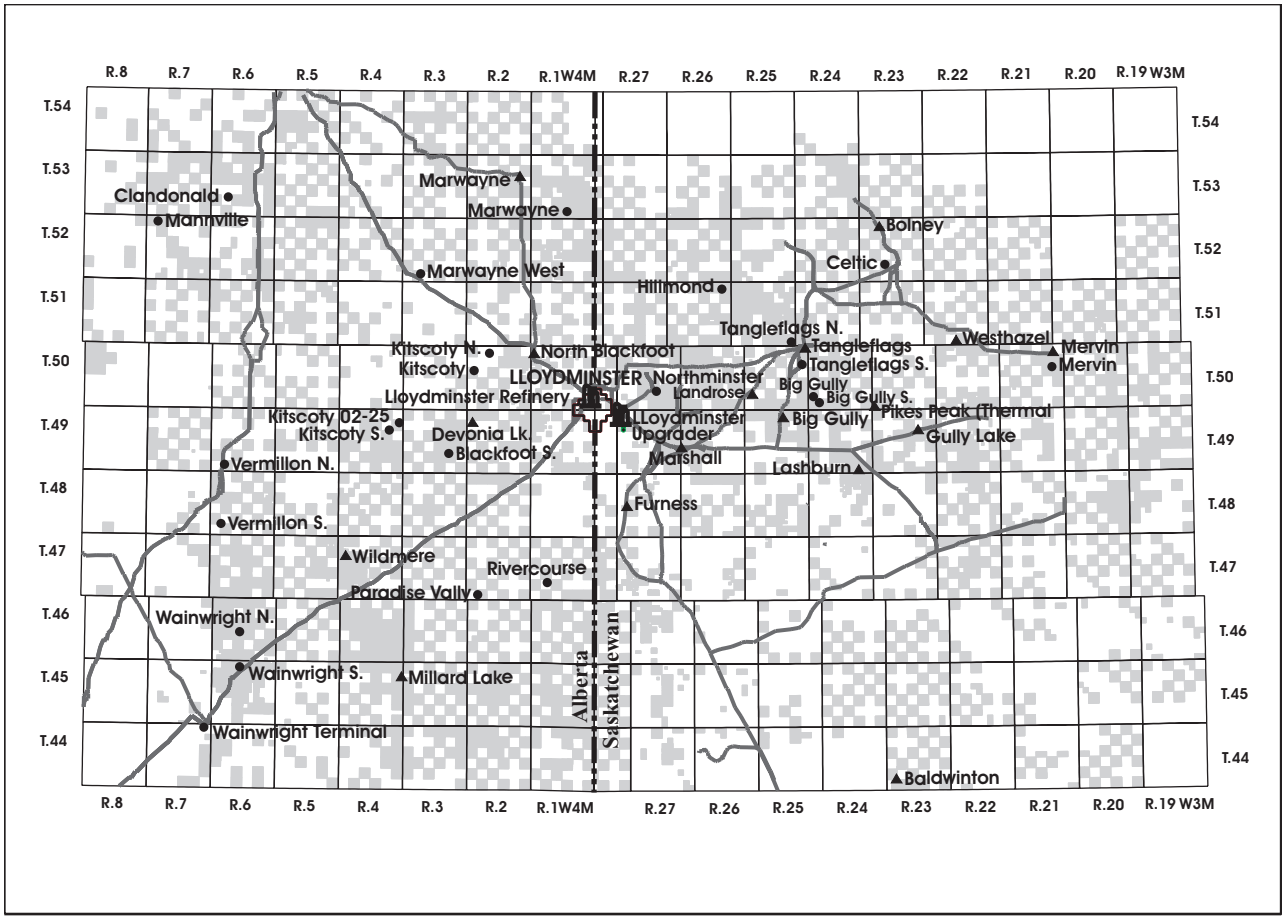
We currently produce from oil and gas wells ranging in depth from 450 to 650 metres and hold a 100 percent working interest in the majority of these wells. We produce heavy oil from the Lloydminster area using a variety of techniques, including standard primary production methods, as well as steam injection, horizontal well technology and steam assisted gravity drainage (''SAGD''). We have 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. Our net heavy and medium crude oil production from the area totalled 97.4 mbbls/day in 2005. Of the total production, 76.2 mbbls/day was primary production of heavy crude oil, 18.0 mbbls/day was production from our thermal operations at Pikes Peak (cyclic steam), Bolney/Celtic (SAGD) and the Lashburn pilot (SAGD), and 3.2 mbbls/day was from the medium gravity waterflooded fields in the Wainwright and Wildmere areas. We believe that the future growth from this area will be driven by primary heavy oil production and new thermal projects.

In the Lloydminster area we own and operate 16 oil treating facilities, all of which are tied into our heavy oil pipeline systems. These pipeline systems transport heavy crude oil from the field locations to our Lloydminster asphalt refinery, to the Husky Lloydminster Upgrader and to the Enbridge Pipeline and Express Pipeline systems at Hardisty, Alberta.

We are focused on increasing our heavy oil production and believe that our 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.

We also produce natural gas from numerous small shallow natural gas pools in the Lloydminster area (approximately 73 bcf of proved reserves). Our total gross natural gas production from the area during 2005 was 55.8 mmcf/day.

Lloydminster Area



British Columbia Foothills/Northwest Plains

Rainbow Lake Area

Rainbow Lake, located approximately 700 kilometres northwest of Edmonton, Alberta, is the site of our 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 percent. Our production in this area is derived from more than 50 oil and gas pools extending over 1,300 square kilometres.

We use 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 the miscible flood used at Rainbow Lake, has increased the estimated amount of recoverable crude oil-in-place from 50 to 70 percent 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, we 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. We use horizontal drilling techniques, including the re-entry of existing well bores, to maintain the level of crude oil production and to increase recovery rates. We plan to continue exploration efforts to supplement our development initiatives in the Rainbow Lake area. Husky's gross production from this area averaged 7.8 mbbls/day of light crude oil and NGL and 34.1 mmcf/day of natural gas during 2005.

We hold a 50 percent interest in, and operate, 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 the winter of 2005, Husky installed a dew point facility and compressor at Bivouac to eliminate a pipeline restriction to the Rainbow Lake plant which limited production to 4 mmcf/day. With completion of this facility in May 2005, production from Bivouac increased to 14 mmcf/day. Plans for 2006 are to drill sufficient wells to fill the facility capacity of 20 mmcf/day.

We hold an interest in two significant non-operated properties in the Rainbow area. They include the Ekwan/Sierra property in northeastern British Columbia and the Bistcho/Cameron Hills property straddling the Alberta and Northwest Territories border. Our gross production from these properties currently averages 11.0 mmcf/day of natural gas and 143 bbls/day of liquid hydrocarbons. We also hold a working interest in the Encana Sierra gas plant and the Paramount Bistcho gas plant. We are active in both these areas with development and exploration drilling. In these two areas we hold in excess of 200,000 acres of undeveloped land.

Slave Lake Area

The Slave Lake area of northern Alberta, which includes the Slave Lake, Sawn Lake, Red Earth, Lubicon, Nipisi, Utikuma and other properties, has been primarily a light oil producing area located approximately 370 kilometres northwest of Edmonton. We operate and hold an average 80 percent working interest in several properties in this area. Gross production from our properties was 3.7 mbbls/d of crude oil and 25 mmcf/d natural gas in 2005. The average working interest in these lands is 80 percent. Infrastructure includes a 100 percent working interest in a 30 mmcf/day sour gas plant and three oil batteries. We plan to continue development drilling and waterflood optimization for both crude oil and natural gas targets in this area. In addition, we will assess oil sands deposits for potential primary production.

High Level Area

The High Level area of Alberta is approximately 600 kilometres northwest of Edmonton, Alberta. We are the operator and hold close to 100 percent working interest in our properties. The area holds shallow Bluesky gas reservoirs that are characterized as low deliverability and low decline that are being developed with a drilling density of three wells per section. We intend to continue to develop this area by drilling undeveloped sections, infill drilling, land acquisitions and step out exploration. Gross production from this area in 2005 averaged 32.3 mmcf/day of natural gas. Our plans in 2006 are to drill new wells and recompletions to fully utilize facilities and optimize operating costs.

Athabasca Area

The Athabasca area is located approximately 200 kilometres northeast of Edmonton, Alberta. Natural gas is produced from the Clearwater, Colony, McMurray and Wabasca or combination of these zones that lie at a depth of approximately 600 metres. Gross natural gas production from this district was 49.4 mmcf/day in 2005. The largest asset in the area is at Amadou which consists of a 22 mmcf/day dehydration facility, 5,800 horsepower of compression and a gathering system which collects natural gas from an area four townships in size. Amadou produced 13.4 mmcf/day in 2005. Our plans for 2006 are to continue with development drilling, recompletions and facility optimizations to keep existing infrastructure fully utilized and optimize unit operating costs. In 2006 we also plan to evaluate the existing oil sands leases and prospective oil sands leases for primary production potential.

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 60 mmcf/day. We hold a 34 percent interest in two unitized wells, a 24 percent and a 50 percent interest, respectively, in two non-unit wells, and act as the contract operator of the Blackstone wells. Production from these wells is processed at the Ram River gas plant.

We hold an average 72 percent interest in, and are 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 2005, the plant operated at approximately 90 percent of its design rate capacity. The Ram River plant processes in excess of 10 percent of our total gross natural gas production, which includes an average of 44 mmcf/day of our gross production from the Blackstone, Brown Creek, Cordel and Stolberg fields and an average of 20.6 mmcf/day of our gross 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 other gas plants, averaged 5.1 mmcf/day of natural gas, bringing our total gross production of natural gas from the Ram River area to 65 mmcf/day in 2005. Our 2006 plans for the Ram River area include continued exploration and development along the Mississippian trend and evaluating deeper targets.

Our sour gas pipeline network supports the Ram River plant. We operate a network of 845 kilometres of sour gas pipelines in the Ram River area and hold a 30 percent 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.

We believe 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 us 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. In 2005, with the addition of Shell Tay River gas volumes and continued success along the Chungo Mississippian trend, net processing income was $25.3 million.

Kaybob Area

The Kaybob area consists of land located in the Fox Creek area of Alberta. The Kaybob area consists of four main areas. The Kaybob South Beaverhill Lake Unit 1 (35.6 percent working interest), Kaybob South Triassic Unit 1 (40.5 percent working interest), Kaybob South Triassic Unit 2 (26.8 percent working interest), and non-unit lands (various working interests from gross overriding royalty to 100 percent working interest).

We have a 17.8 percent working interest in the sour portion and a 20.4 percent working interest in the sweet gas portion of the plant. We also have various working interests in sweet gas gathering and compression facilities in the area. Our gross production from the area during 2005 was 390 bbls/day of oil, 463 bbls/day of NGL and 11 mmcf/day of natural gas.

Alberta/British Columbia Plains

Boundary Lake Area

We hold a 50 percent working interest in the Boundary Lake Gas Unit and a 34 percent and 19 percent interest in the Boundary Lake oil unit 1 and 2, respectively, in northeast British Columbia. Our natural gas production from this area is derived from five Belloy sour gas pools, and is processed at the nearby Boundary Lake processing plant. Our gross production from this area was 12 mmcf/day of natural gas and 1.6 mbbls/day crude oil and NGL from the Boundary Lake units during 2005.

Valhalla and Wapiti Area

We hold an approximate 30 percent interest in three Valhalla oil units, a 100 percent interest in the Valhalla non-unit waterflood wells and a 100 percent 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. Our gross production from these properties averaged 3.3 mbbls/day of crude oil and NGL and 8.5 mmcf/day of natural gas in 2005.

Kakwa Area

We hold an average 60 percent working interest in oil and gas processing facilities and associated oil and gas gathering systems in the Kakwa area. Our gross production from this area was 14.8 mmcf/day of natural gas, 491 bbls/day NGL and 307 bbls/day of oil in 2005.

Lynx and Copton Area

Husky has had a significant focus on exploration activity in the Lynx/Copton area of western Alberta drilling and tie-in of four net wells in the area, increasing production from 12 mmcf/d to 16 mmcf/d. We plan to continue to develop this immature asset in 2006 to maintain Husky production at 15 mmcf/d.

Foothills West

Caroline Area

We hold an 11 percent working interest in the 32,000 acre Caroline natural gas field located approximately 97 kilometres northwest of Calgary. The field has a high proportion of NGL and as a result the economics of this field are enhanced.

We also hold an 11 percent interest in the Caroline sour gas processing facility. The plant is presently running at a license limit of 113 percent of design capacity and is processing approximately 124 mmcf/day of total plant sales gas and 39 mbbls/day of NGL. Husky's gross production was 3.3 mbbls/day NGL and 11.9 mmcf/day natural gas in 2005.

Edson Area

We hold an average 85 percent working interest in two gas processing facilities and associated gas gathering systems in the Edson area. We operate these properties that had average gross production of 34.0 mmcf/day of natural gas and 1.4 mbbls/day of NGL in 2005. Husky had a significant development program of 20 development in 2005 with plans to drill 20 wells in 2006 to increase production to 40 mmcf/day.

Sikanni Area

We hold interests in properties in the Sikanni and Federal areas of northeast British Columbia, which averaged gross production of 9.8 mmcf/day of natural gas from four wells in 2005. The production flows through our gathering systems for processing at third party plants at Sikanni and McMahon. In December 2005 Husky's gross production increased by 6 mmcf/day with the payout of a reversionary working interest on a farmout well in the Lily area.

Graham Area

We hold a 40 percent working interest in lands in the Graham area of northeastern British Columbia. Our gross production from this area averaged 8.3 mmcf/day of gross natural gas sales in 2005. Production from the property is from one Halfway and seven Baldonnel pools. We also hold an interest 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. We hold a 33.2 percent interest in the gas treating unit, 28.2 percent interest in the amine unit and 28 percent interest in the sulphur unit.

East Central Alberta

Craigend 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 450-900 metres in the multi-zone Palaeozoic Mannville formation. The main producing areas are Athabasca, Craigend and Cold Lake. We operate 32 facilities with a pipeline system and an average working interest of 90 percent in the producing wells. We intend to continue to develop this area with infill, step out and exploratory wells to optimize recovery and develop new pools in order to keep the facilities operating at capacity. Our gross production from this area averaged 54.3 mmcf/day of natural gas and 635 bbls/day of crude oil in 2005.

Red Deer and Hussar Area

The core of the Red Deer and Hussar area is between Calgary, Drumheller and Sylvan Lake. Husky operates 21 facilities with gas gathering systems in this area. Our gross production from this area averaged 57.3 mmcf/day of natural gas and crude oil and NGL of 2.4 mmbbls/day in 2005. We intend to continue to develop the natural gas potential of this area with infill, step out and exploratory wells to optimize gas recovery and develop new pools in order to operate the facilities at capacity. We are involved in coal bed methane development in this area, and by year-end 2005 had drilled 300 wells and built extensive infrastructure. There were 120 wells tied-in by year-end that were producing gross 10 mmcf/day of natural gas. In 2006, we plan to drill 300 more wells to reach an expected gross 35 mmcf/day of natural gas.

Provost Area

The centre of the Provost area is approximately 240 kilometres southeast of Edmonton. It is predominantly a medium crude oil area that averaged gross production of 15.4 mbbls/day of crude oil and 22.2 mmcf/day of natural gas

in 2005. We intend to selectively drill lower risk oil locations and focus on managing operating costs and improving oil recovery, as well as increasing our focus on natural gas exploration and development. In 2006, we intend to continue to develop several of our 2004 and 2005 natural gas discoveries. There is significant competition in the area for land as well as infrastructure. We have a large land position and maintain close to a 100 percent working interest in most of our facilities.

Southern Alberta and Southern Saskatchewan

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 our properties in this area averaged 16.7 mbls/day of crude oil and 58.2 mmcf/day of natural gas during 2005.

We operate 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.

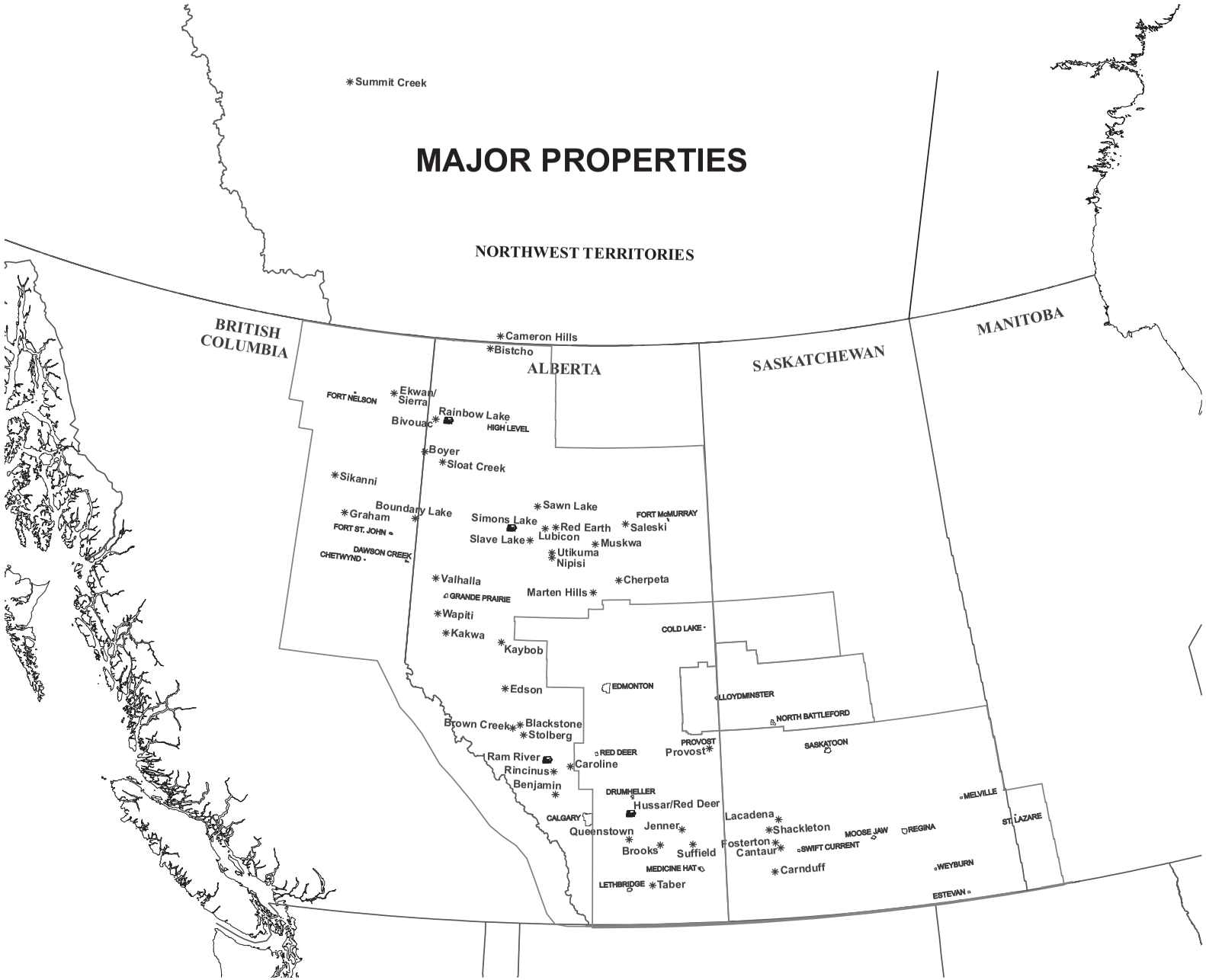
At the Shackleton/Lacadena Milk River shallow gas project, 132 wells were drilled and tied-in in 2005. The project was producing at a rate of 48.8 mmcf/day of natural gas at December 31, 2005 from a total of 330 wells. In 2006, we plan to drill between 65 and 100 additional step out and infill wells and add two 8 mmcf/day sales gas plants.

Southern Alberta Area

Taber and Brooks are our two major centres in southern Alberta. We operate 27 oil facilities and three natural gas facilities with an average working interest of 95 percent. 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 Etzikom, near Taber, we operate an alkaline-polymer flood to increase recovery from the Cretaceous Mannville reservoir and we are currently implementing additional floods at Warner and Crowsnest for 2006, and 2007 respectively. Our gross production from this area averaged 10.2 mbbls/day of crude oil and 32.1 mmcf/day of natural gas during 2005.

During 2005 we divested of approximately 1,100 bbls/day of heavy crude production at Jenner, which had very high operating costs, and minimal upside.

MAJOR PROPERTIES



Oil Sands

Athabasca, Cold Lake and Peace River

Husky currently holds interests in 433,610 net acres, including 7,680 acres of petroleum and natural gas rights, in the bitumen prone areas of Athabasca, Cold Lake and Peace River.

In addition to interests in the 353,930 net acres in the Cold Lake and Athabasca regions in northeastern Alberta, Husky holds an interest in 79,680 net acres in the Peace River region of northern Alberta.

Tucker

In May of 2004 we received approval from the Alberta Energy and Utilities Board to develop the Tucker in-situ oil sands project. Tucker is located 30 kilometres northwest of Cold Lake, Alberta. The Tucker project will utilize SAGD technology and will have a design rate capacity of 30 mbbls/day. Construction commenced in late 2004 and as of year-end 2005 drilling operations were 85 percent complete and facility construction was approximately 65 percent complete. The project remains on schedule and on budget and we expect to commission the facility in the third quarter of 2006 with first oil production before year-end 2006.

Sunrise

The Sunrise in-situ oil sands project is located in the Athabasca region of Alberta. Stratigraphic delineation drilling over the last four years has confirmed a large recoverable resource base with original bitumen-in-place under Husky lands estimated at 10.6 billion barrels. The commercial project application submitted to the Alberta Energy and Utilities Board (AEUB) and Alberta Environment envisioned development to 200 mbbls/day in 50 mbbls/day phases. The application was approved by the AEUB in December 7, 2005. Husky worked closely with local stakeholders including several First Nations and the local environmental coalition and obtained regulatory approval approximately 15 months after submission. During 2006 Husky will conduct front end engineering and design for the extraction aspects of the project and will develop optimal transportation and product marketing plans.

Caribou

Our Caribou oil sands lands are located in the Cold Lake Air Weapons Range and comprise 35,840 acres. Pilot testing was conducted in the early 1990s. Further stratigraphic drilling in 2005 yielded encouraging results, confirming that the Clearwater reservoirs being developed to the south by other operators extend onto Husky's Caribou lands. In 2006 Husky will drill 15 additional stratigraphic (resource assessment) wells and begin preparation of the development project application.

Saleski

Our largest bitumen deposit, with original bitumen-in-place estimated at 16.8 billion barrels is located approximately 120 kilometres west of Fort McMurray, Alberta. The bitumen is contained in the Grosmont carbonate formation. During 2005 Husky examined available geological data and the results of previous pilot projects. A 20 well program will be conducted in 2006 to provide additional geological data. Since there are no existing operations producing bitumen from the Grosmont carbonate, piloting of various technologies will be required over the coming years to identify commercial development approaches.

Oil Sands Leases

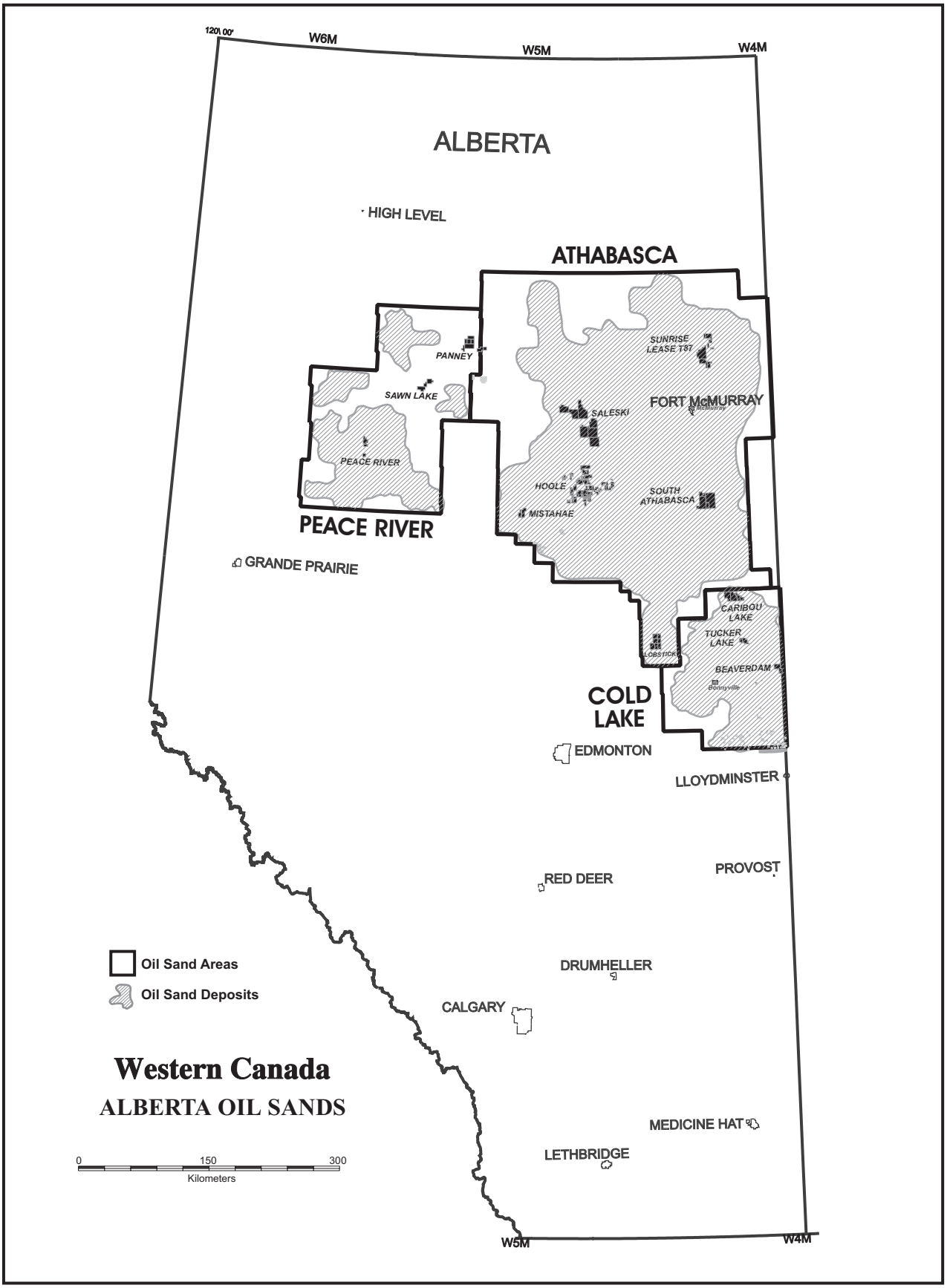
General Location Name	Oil Sands Area	Gross Acres	Net Acres	Husky Operator
South Athabasca — overriding royalty	Athabasca	35,601	—	No
South Athabasca	Athabasca	22,032	11,016	Yes
Sunrise — In situ[1]	Athabasca	57,634	57,634	Yes
Misthae (Drowned, Martin Hills W. & Spur)	Athabasca	28,160	28,160	Yes
Saleski	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	10,080	10,080	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
		519,587	425,930	

Notes:

(1) Not 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) Not 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.


120\ 00'
W6M
W5M
W4M
ALBERTA
HIGH LEVEL
ATHABASCA
PANNEY
SAWN LAKE
PEACE RIVER
SUNRISE LEASE 187
FORT McMURRAY
SALESKI
HOOLE
MISTAHAE
SOUTH ATHABASCA
PEACE RIVER
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
0
150
300
Kilometers
W5M
W4M

Offshore East Coast — Canada

Husky's offshore East Coast exploration and development program is focused in the Jeanne d'Arc Basin on the Grand Banks offshore the coast of Newfoundland, which contains the Hibernia, Terra Nova and White Rose oilfields. We hold ownership interests in the Terra Nova and White Rose oilfields as well as in a number of smaller undeveloped fields in the central part of the basin. We presently hold working interests ranging from 5.33 to 72.5 percent in 15 Significant Discovery License (''SDL'') areas in the Jeanne d'Arc Basin. We are also the operator of 10 exploration licenses (''EL'') on the Grand Banks and also hold an interest in one non-operated EL on-shore in the province of Nova Scotia. In 2005, we acquired 2 ELs. One of the licenses, EL 1096, totalling 5,263 acres is directly north of the Terra Nova oilfield and the other, EL 1094, totalling 33,321 acres is directly west of the Hebron significant discovery area. Husky holds 100 percent of the two licences and operates both. We believe that there is exploration potential in the area, and that our position off the East Coast of Canada will provide growth opportunities for light crude oil production in the medium to long-term.

We will continue technical evaluation of our East Coast exploration acreage. In 2006, we plan to acquire 3-D seismic over several license areas in the Northern Jeanne d'Arc Basin as well as south of the White Rose oilfield. Depending on drilling rig availability, we plan on drilling several delineation/exploration wells in 2006.

In January 2006, we relinquished two ELs following the drilling of the Lewis Hill G-85 exploration well, which was plugged and abandoned.

Terra Nova Oilfield

The Terra Nova oilfield is located approximately 350 kilometres southeast of St. John's, Newfoundland and Labrador, 35 kilometres southeast of the Hibernia oilfield, in 91 to 100 metres of water. The Terra Nova oilfield is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Our current pooled interest in the Terra Nova field is 12.51 percent. This interest is subject to change, pending re-determination once the field has been further delineated. Production at Terra Nova commenced in January 2002. Husky's gross share of production in 2005 from the Terra Nova field was 4.5 mmbbls based on an average of 12.4 mbbls/day annual production rate.

As at December 31, 2005, there were 12 development wells drilled in the Graben area, eight production wells and four injection wells. In the East Flank area there were 11 development wells including six production wells and five injection wells. Drilling operations are expected to continue in 2006 based on a 36 well depletion plan for the Graben and East Flank areas. An extended reach well was drilled from the East Flank subsea template to the Far East Central area in 2005 and production will commence during the first quarter of 2006. Husky continues to promote drilling additional delineation wells in the Far East area and a Far East South well location, PF8, will be included in the 2006 drilling program. As at December 31, 2005, we had booked 13.7 mmbbls of gross light crude oil in the proved developed category and 6.7 mmbbls of proved undeveloped. These reserves are estimated to be capable of being produced using primary and secondary (waterflood and gasflood) production techniques.

White Rose Oilfield

The White Rose oilfield, which we operate, is located 354 kilometres off the coast of Newfoundland approximately 48 kilometres east of the Hibernia oilfield on the eastern section of the Jeanne d'Arc Basin. Husky holds a 72.5 percent interest in the White Rose oilfield. At plateau production, the oilfield is estimated to produce approximately 100,000 barrels per day and Husky's share is expected to average 67,500 barrels per day on an annual basis. Husky's share of proven and probable reserves for the field is estimated at 173 million barrels including the currently undeveloped West Avalon pool.

In August 2005, the *SeaRose FPSO* (floating production, storage and offloading vessel) arrived at the White Rose oilfield, 350 kilometres east of St. John's, Newfoundland and Labrador, following a 48-hour journey from Marystown, Newfoundland and Labrador. The *SeaRose FPSO* had arrived in Marystown in April 2004, where topsides fabrication, installation and commissioning were carried out. The *SeaRose FPSO* departed Marystown on August 20, 2005. The vessel connected to a subsea production system and then underwent approximately three months of offshore hook-up and commissioning in preparation for first oil.

In November, 2005 first oil production was achieved marking the successful completion of the third offshore oil development for Newfoundland and Labrador. Oil was introduced into the process stream on the *SeaRose FPSO* on November 12, 2005. The White Rose field is expected to reach plateau production of 100,000 barrels per day in the first half of 2006. Husky has chartered two shuttle tankers, the *Heather Knutsen* and the *Jasmine Knutsen,* to transport

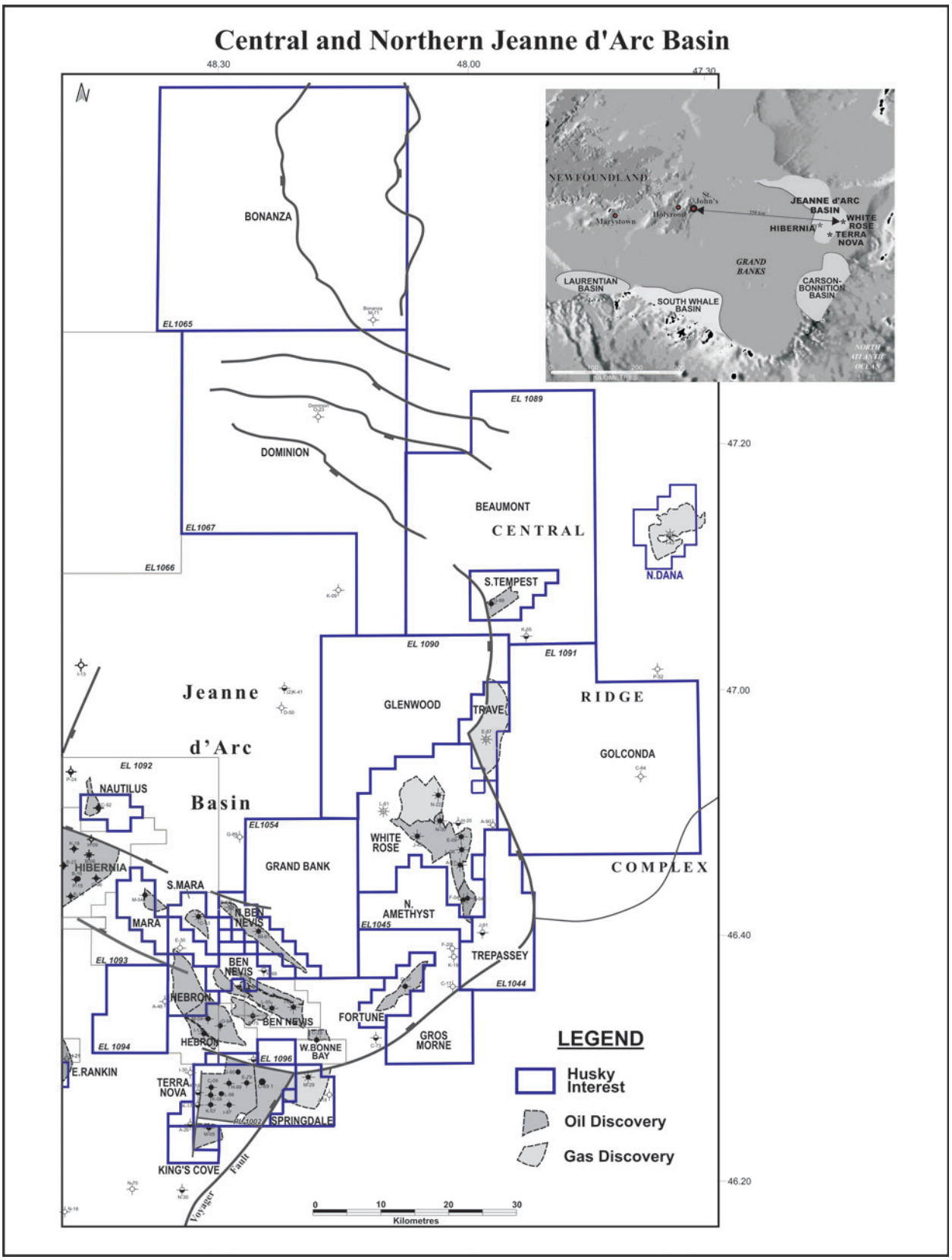
White Rose crude oil to market. The Samsung-designed double-hulled tankers each have a crude oil capacity of one million barrels. In December 2005, Husky offloaded three shipments of crude oil from the *SeaRose FPSO*. Approximately 2.4 million barrels of oil were produced from the White Rose field in 2005, with 1.74 million net to Husky.

Development drilling activity at the field is on schedule with 10 wells drilled as at the end of 2005, including three production wells, one gas injection well and six water injection wells. All well results were as predicted, or better. Initial production from the field supports an average oil production per well of 25,000 bbls/day.

In 2005, three pre-front end engineering and design studies relating to East Coast Natural Gas development were completed. The studies were undertaken by Husky to evaluate the viability of producing and transporting natural gas from White Rose. The studies commissioned focused on screening assessment of compressed natural gas (CNG) as one potential development option. During 2005 the scope was widened to consider and rank all technical options for development of the east coast natural gas resource. Husky also entered into a Memorandum of Understanding with other east coast operators to explore potential synergies and a regional solution.

Husky intends to progress technical screening to a shortlist of solutions complete with high level cost estimates. In parallel, delineation drilling will improve estimates of the reserve base ahead of future development. We will also continue to work closely with the Government of Newfoundland and Labrador as they work to develop a suitable fiscal regime during 2006.

East Coast


Central and Northern Jeanne d'Arc Basin
48.30
48.00
47.30
47.20
47.00
46.40
46.20
BONANZA
EL1065
DOMINION
EL 1089
BEAUMONT
CENTRAL
EL1067
EL1066
S.TEMPEST
N.DANA
EL 1090
EL 1091
Jeanne
d'Arc
Basin
GLENWOOD
TRAVE
RIDGE
GOLCONDA
EL 1092
NAUTILUS
EL1054
WHITE
ROSE
HIBERNIA
GRAND BANK
COMPLEX
S.MARA
N.BEN
NEVIS
MARA
N.
AMETHYST
EL1045
EL 1093
BEN
NEVIS
TREPASSEY
EL1044
HEBRON
BEN NEVIS
FORTUNE
HEBRON
W.BONNE
BAY
GROS
MORNE
EL 1094
EL 1096
E.RANKIN
TERRA
NOVA
SPRINGDALE
KING'S COVE
Voyager Fault
0
10
20
30
Kilometres
LEGEND
Husky
Interest
Oil Discovery
Gas Discovery
NEWFOUNDLAND
St.
John's
Holyrood
Marystown
JEANNE d'ARC
BASIN
HIBERNIA
WHITE
ROSE
TERRA
NOVA
GRAND
BANKS
LAURENTIAN
BASIN
SOUTH WHALE
BASIN
CARSON-
BONNITION
BASIN
NORTH
ATLANTIC
OCEAN

International

Our international exploration and development program is focused on Southeast Asia. In China, we have a 40 percent interest in one producing oilfield and interests in six exploration blocks. The bulk of these interests are in the South China Sea. In Indonesia, we have a 100 percent interest in the Madura block.

South China Sea

Wenchang

The Wenchang oilfield is located in the western Pearl River Mouth Basin, approximately 400 kilometres south of Hong Kong and 100 kilometres east of Hainan Island. We hold a 40 percent working interest in the oilfields, which commenced production in July 2002. The Wenchang 13-1 and 13-2 oilfields are producing from 24 wells in 100 metres of water into a FPSO (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 degree API, similar to the benchmark Minas blend. At December 31, 2005, our gross proved reserves at Wenchang were 17.3 mmbbls of crude oil and NGL. Our gross production averaged 16.0 mbbls/day during 2005. Two near field wildcat exploration wells were drilled in 2005 with no economic success.

Block 39/05

We 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 fields with a commencement date of October 1, 2001. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. In January 2003, the Qionghai 18-1-3 exploration type stratigraphic well on the block 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. In 2004, we relinquished 25 percent of Block 39-05. Husky will relinquish an additional 25 percent of 39-05 in 2006. Husky is continuing to evaluate the geological information for the remainder of this block and expects to undertake additional exploration drilling in 2007.

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 oilfields. The 23-15 block is approximately 1,325 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 percent working interest. In 2003, we completed a 1,000 square kilometre 3-D seismic survey shot over a portion of block 23-15. Husky fulfilled its Phase I commitments on Block 23-15 with the drilling of Wushi 17-1-1 in 2005. Husky is currently evaluating the results of WS17-1-1 and expects to announce its intentions with respect to Phase II commitments in 2006. Husky fulfilled its Phase I commitments on Block 23-20 with drilling of Wushi 32-1-1 in 2005. Husky is currently evaluating the results of WS32-1-1 and its intentions with respect to Phase II commitments in 2006.

Block 29/26

Husky executed a production sharing contract with CNOOC for the 29-26 exploration block with a commencement date of October 1, 2004. The block is located in the South China Sea approximately 300 kilometres southeast of Hong Kong and 65 kilometres southeast of the Panyu gas discovery. The block covers an area of approximately 3,965 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.$8 million. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. Husky has contracted a deep-water drill ship and plans to spud the first exploratory well in the first quarter of 2006.

Block 40/30

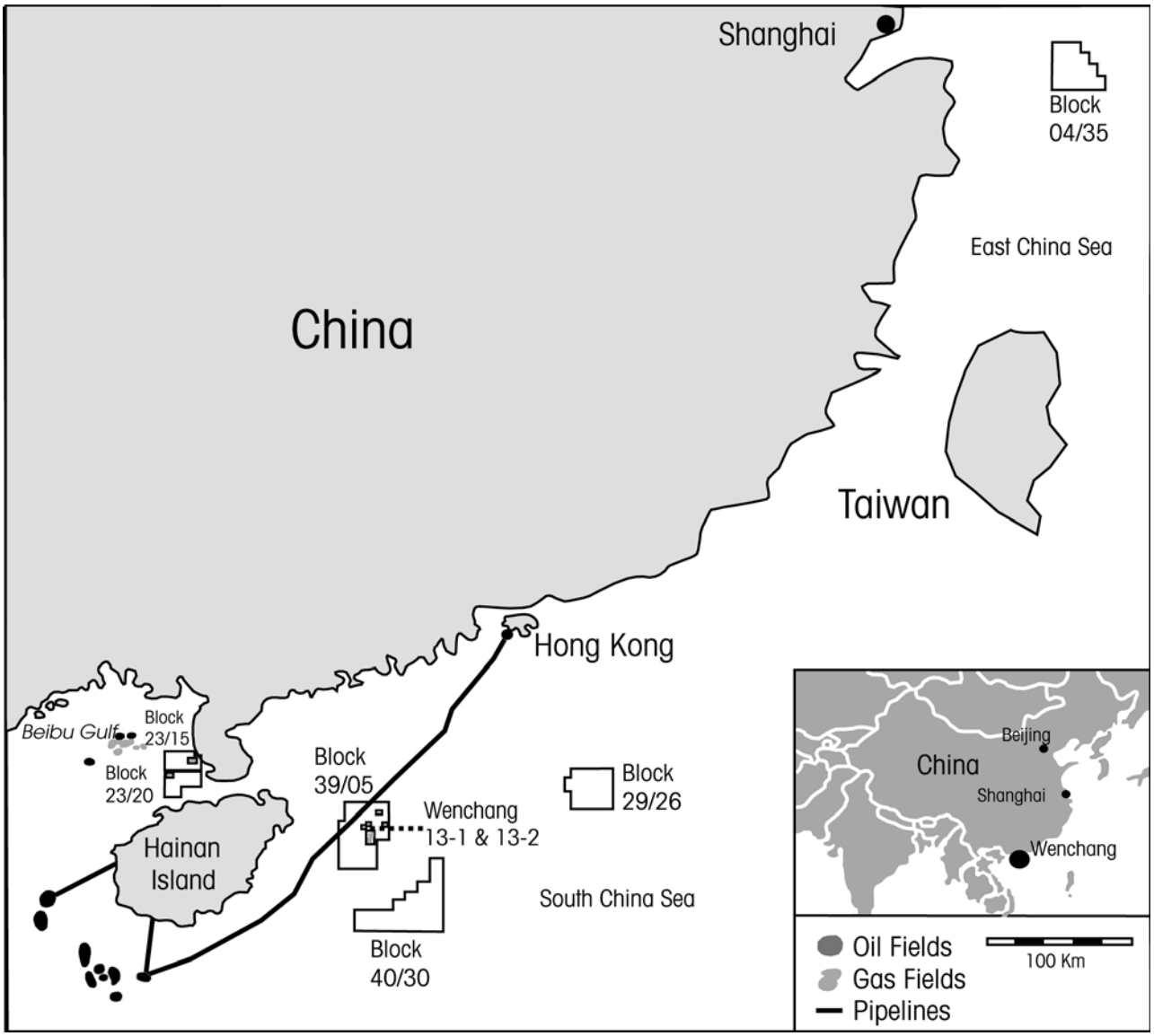
We executed a production sharing contract with CNOOC for the 40-30 exploration block with a commencement date of February 1, 2003. The block is located in the South China Sea approximately 100 kilometres south of the Wenchang 13-1 and 13-2 oilfields. The block covers an area of approximately 6,705 square 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 percent working interest. We fulfilled our Phase I obligations of the petroleum contract with the drilling of ChangChang (''CC'') 12-1-1. The CC 12-1-1 is the deepest-water well in the South China Sea to date. The CC12-1-1 well was plugged and abandoned without testing.

East China Sea

Block 04/35

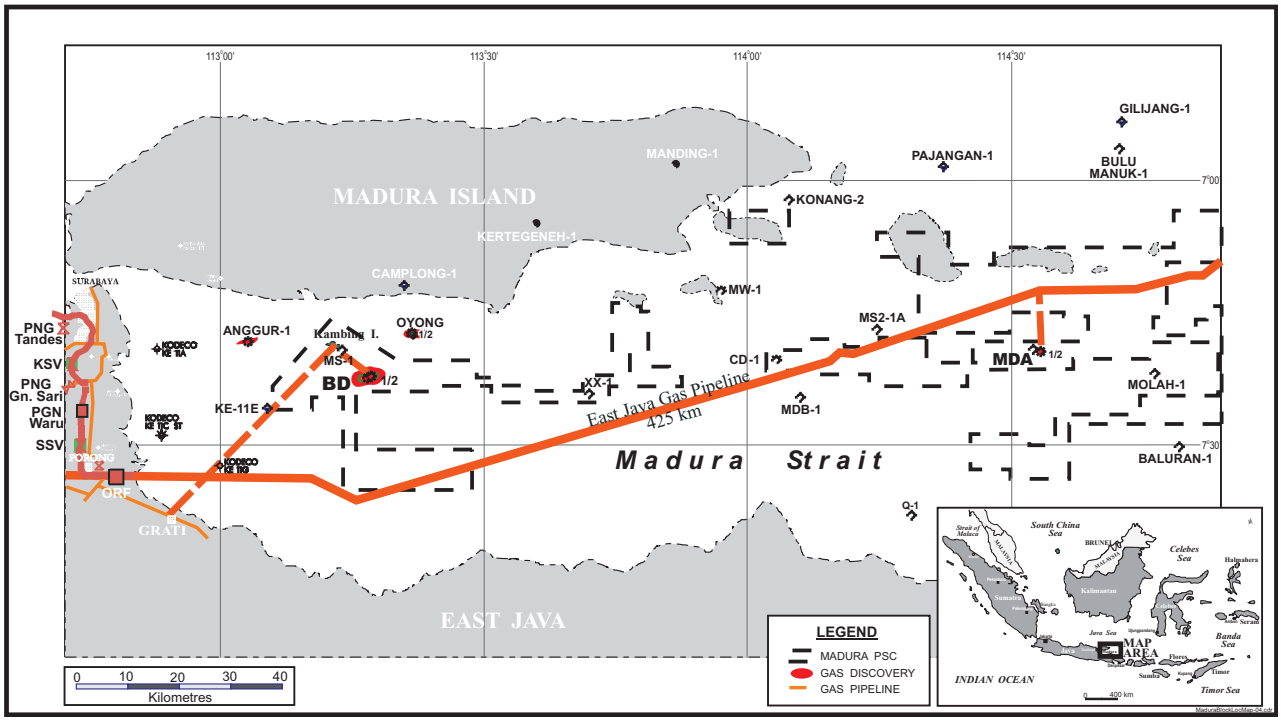
We executed a production sharing contract with CNOOC for the 04-35 exploration block with a commencement date of December 1, 2003. The block is located in the East China Sea approximately 350 kilometres east of the city of Shanghai and covers an area of approximately 4,835 square kilometres. The production sharing contract requires the drilling of a single exploration well in the first exploration phase 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 are complete and we expect to fulfill our first phase commitments early in 2006. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. Husky has completed its preliminary geological evaluation and expects to begin exploration drilling in 2006.

China



Madura Strait, Indonesia

We have a 100 percent interest in the approximately 2,795 square kilometre Madura Strait production sharing contract (''PSC''), offshore East Java, Indonesia. There have been two natural gas fields discovered on the block. The larger of these is the Madura BD field, which has been granted commercial status and had a plan of development approved by the Indonesian state oil company in 1997. The field was to supply natural gas to a new proposed independent power plant, however construction of the power plant did not proceed due to economic issues that occurred in Indonesia. Husky has begun discussions to establish a new natural gas sales contract for Madura production and in addition, the development engineering re-validation work commenced in 2005 for the production facilities. In 2006, we expect to complete negotiation of the gas sales contract, submit a revised Plan of Development to the Indonesian regulatory authority for approval and negotiate an extension to the PSC term. Production is expected to come on stream approximately three years after these agreements are negotiated.



Shatirah, Libya

Husky has a non-operated 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 75 percent of Husky's heavy crude oil production from the Lloydminster area. Husky also markets heavy crude oil production directly to refiners located in the mid-west and eastern United States and Canada. Husky markets its light and synthetic crude oil production to third party refiners in Canada, the United States and Asia. Natural gas liquids are sold to local petrochemical end users, retail and wholesale distributors and to 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,		
	2005	2004	2003
	(mmcf/day)		
Sales to end users			
United States	357	407	382
Canada	212	187	156
	569	594	538
Sales to aggregators	31	34	43
Internal use[1]	80	61	30
	680	689	611

Note:

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

We also market third party natural gas production in addition to our own production.

Delivery Commitments

The following table shows the future commitments to deliver natural gas from our reserves in Western Canada. Our 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
2006	25.9	3.98	19.7
2007	20.4	4.51	19.7
2008	20.4	4.75	11.8
2009	20.4	5.00	0.9
2010	20.4	5.28	0.5
2011	20.4	5.57	—
2012	20.0	5.47	—
2013	20.0	3.67	—
2014	6.2	3.67	—

Midstream Operations

Overview

The midstream operations include:

- Upgrading — the upgrading of heavy crude oil into synthetic light 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
- Commodity 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 (''Upgrader''), which is a heavy oil upgrading facility located in Lloydminster, Saskatchewan.

The 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 Upgrader recovers the diluent, which facilitates pipeline transportation of heavy crude oil, and returns it to the field to be reused.

The Upgrader provides heavy crude oil access to a new market, which we believe 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 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 67 mbbls/day of synthetic crude oil. Production at the Upgrader averaged 56.7 mbbls/calendar day of synthetic crude oil and 9.9 mbbls/day of diluent in 2005 compared with 55.2 mbbls/day of synthetic crude oil and 9.4 mbbls/day of diluent in 2004. Throughput at the Upgrader in 2005 was higher than 2004 due to improved plant reliability. In addition to synthetic crude oil and diluent, the Upgrader also produced, as by-products of its upgrading operations, approximately 312 lt/day of sulphur and 755 lt/day of petroleum coke during 2005. These products are sold in local and international markets. By the end of 2006 it is anticipated that the Upgrader will also be producing 2,500/bbls per day of low sulphur diesel. The profitability of our upgrading operations is primarily dependent upon the differential between the price of synthetic crude oil and the price of heavy crude oil. The Upgrader shipped its 250 millionth barrel of Husky Synthetic Blend in May 2005.

The Upgrader is currently undergoing a number of debottleneck projects. These projects, upon completion in late 2006, are expected to increase upgrading capacity to 82 mbbls/day of synthetic crude oil and diluent.

Infrastructure

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. Our 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 Upgrader and our 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 of the Enbridge Pipeline system and the Express Pipeline system. The crude oil is transported to eastern and southern markets on these pipelines. Our 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:

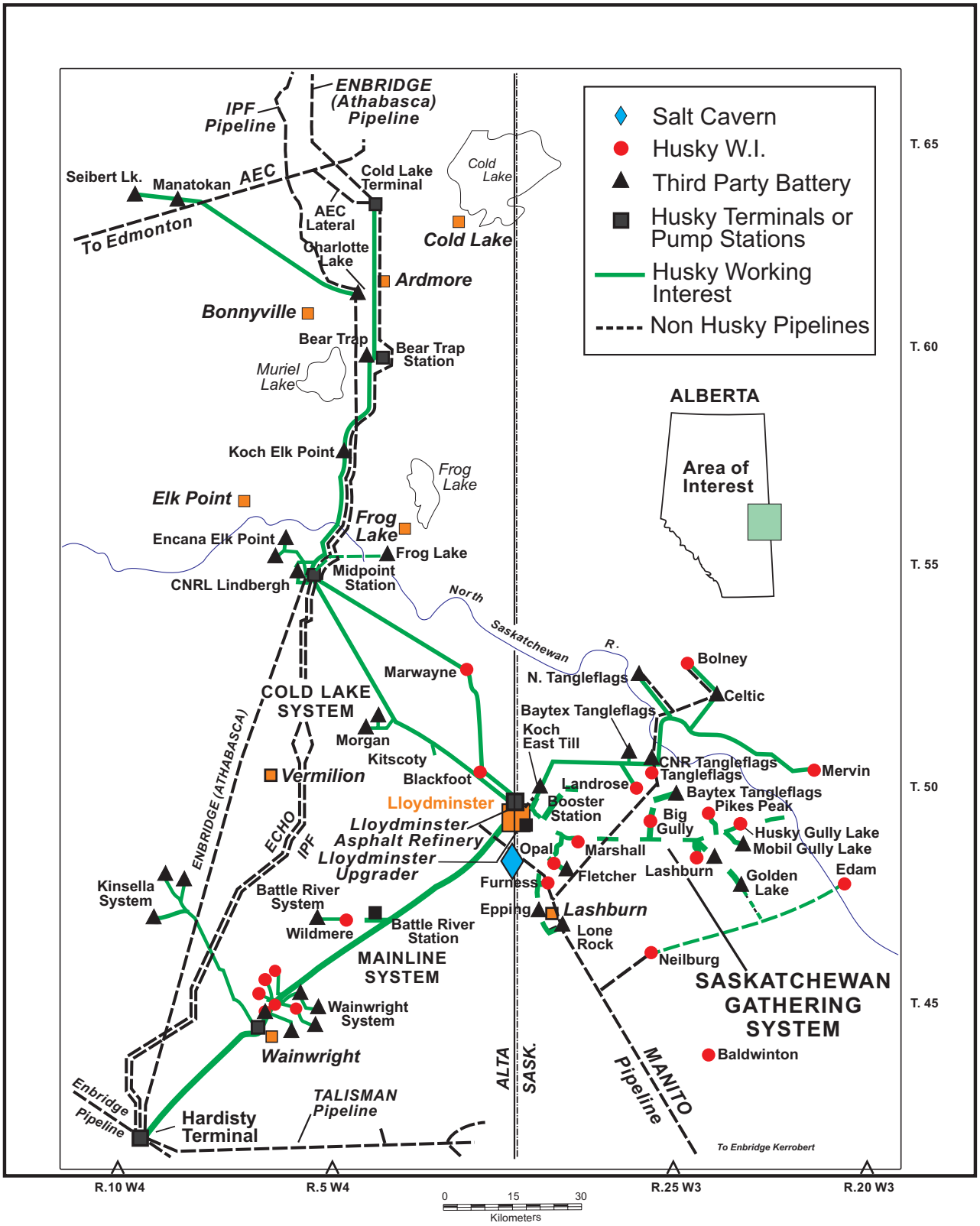
	Years ended December 31,		
	2005	2004	2003
		(mbbls/day)	
Combined pipeline throughput	474	492	484

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.

We consider the expansion and optimization of our pipeline systems in the Lloydminster area to be necessary to further our 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.

We operate 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 percent interest in a 215 MW natural gas fired cogeneration facility at the site of the 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 Upgrader.

Husky has a 50 percent 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 northwestern 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. We also market petroleum coke, a by-product from the Lloydminster Upgrader. We supply feedstock to our Upgrader and asphalt refinery from our own and third party heavy oil production sourced from the Lloydminster and Cold Lake areas. We also sell blended heavy crude oil directly to refiners based in the United States and Canada. Our extensive infrastructure in the Lloydminster area supports its heavy crude oil refining and marketing operations.

We market light and medium crude oil and NGL sourced from our own production and third party production. Light crude oil is acquired for processing by third party refiners at Edmonton, Alberta and by our refinery at Prince George, British Columbia. We market the synthetic crude oil produced at our Upgrader in Lloydminster to refiners in Canada and the United States.

We market natural gas sourced from our own production and third party production. We are currently committed to gas sales contracts with third parties, which in aggregate do not exceed amounts forecast to be deliverable from our reserves. Our contracts are with customers located in eastern Canada/northeastern United States (28 percent), mid-west United States (23 percent), Western Canada (46 percent) and west coast United States (3 percent). The natural gas volumes sales contracted are primarily at market prices (90 percent). The terms of the contracts remaining at December 31, 2004 are up to one year (74 percent), one year to five years (18 percent) and over five years (8 percent). Husky has acquired rights to firm pipeline capacity to transport the natural gas to most of these markets.

We have developed our commodity marketing operations to include the acquisition of third party volumes in order to increase volumes and enhance the value of our midstream assets. We plan to expand our marketing operations by continuing to increase marketing activities. We believe that this increase will generate synergies with the marketing of our own production volumes and the optimization of our assets.

Refined Products

Overview

Husky's refined products operations include refining of light crude oil, manufacturing of fuel and industrial grade ethanol, manufacturing of asphalt products from heavy crude oil and retail, commercial and wholesale marketing of refined petroleum products. Our retail network provides a platform for substantial non-fuel related businesses.

Light oil refined products are produced at our refinery at Prince George, British Columbia and are also acquired from 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 are marketed directly or through Husky's eight emulsion plants, four of which are also asphalt terminals located throughout Western Canada.

Branded Petroleum Product Outlets and Commercial Distribution

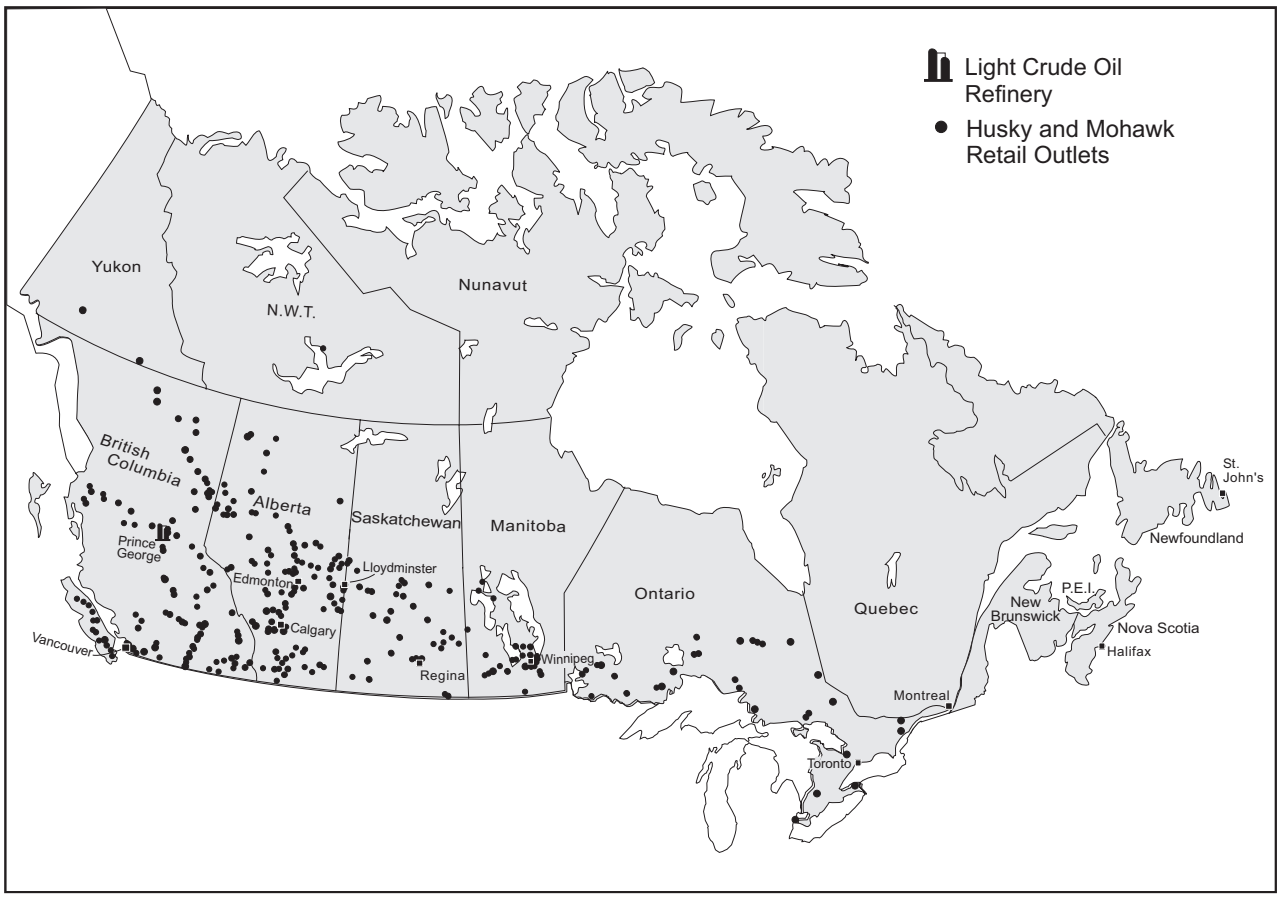
Distribution

As of December 31, 2005, there were 515 independently operated Husky and Mohawk branded petroleum product outlets. These petroleum product outlets include service stations, travel centres and bulk distribution facilities located from the Ontario/Quebec border to the West Coast. The travel centre network is strategically located on major highways and serves the retail market and commercial transporters 24 hours per day, 365 days a 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 Product Outlets

Branded Petroleum Outlets



Independent retailers or agents operate all Husky and Mohawk branded petroleum product 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, 2005:

Retail Outlets	British Columbia & Yukon	Alberta	Sask.	Manitoba	Ontario	Total	2004 Total
Travel Centres	9	8	4	2	13	36	36
Full Serve	10	15	2	2	2	31	37
Full/Self Serve	16	25	6	11	3	61	59
Self Serve	18	12	1	1	1	33	34
Bulk Distributor	1	7	4	1	1	14	14
Card/Key Locks	2	7	0	0	1	10	10
	56	74	17	17	21	185	190
Leased							
Travel Centres	1	0	0	0	0	1	1
Full Serve	3	8	5	4	0	20	24
Full/Self Serve	14	22	4	6	0	46	46
Self Serve	31	22	0	1	0	54	52
Bulk Distributor	3	0	0	0	0	3	3
Card/Key Locks	3	2	0	3	2	10	9
	55	54	9	14	2	134	135
Independent Retailers							
Travel Centres	1	1	0	0	4	6	6
Full Serve	22	15	8	14	7	66	77
Full/Self Serve	17	5	5	1	1	29	28
Self Serve	29	45	4	3	2	83	85
Bulk Distributor	2	4	1	0	0	7	7
Card/Key Locks	1	1	0	0	3	5	3
	72	71	18	18	17	196	206
Total							
Travel Centres	11	9	4	2	17	43	43
Full Serve	35	38	15	20	9	117	138
Full/Self Serve	47	52	15	18	4	136	133
Self Serve	78	79	5	5	3	170	171
Bulk Distributor	6	11	5	1	1	24	24
Card/Key Locks	6	10	0	3	6	25	22
	183	199	44	49	40	515	531
Cardlocks[1]	24	18	4	6	21	73	74
Convenience Stores[1]	178	183	39	46	33	479	484
Restaurants	11	12	4	2	16	45	45

Note:

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

We also market 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 our average daily sales volumes of light refined petroleum products for the periods indicated:

	Years ended December 31,		
	2005	2004	2003
	(mbbls/day)		
Gasoline	28.3	28.3	28.5
Diesel fuel	26.5	23.9	22.1
Liquefied petroleum gas	0.9	1.1	1.2
	55.7	53.3	51.8

Our strategy in respect of our 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. We also plan 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. We are pursuing acquisitions and joint venture opportunities to further enhance our existing distribution network.

Supply

Prince George Refinery

In 2005 Husky completed the upgrade at its Prince George Refinery to produce low sulphur gasoline fuels that meet the Government of Canada's new fuel specification. The cost of the upgrade is expected to be $92 million and with this upgrade refinery nameplate productive capacity was increased 20 percent to 12,000 bbls/day. Upgrades to produce ultra low sulphur diesel will continue into 2006. The Prince George refinery production makes up 22 percent of the Refined Products — Light Oil's fuel supply as it is the lowest cost supply source. The refinery produces all grades of unleaded gasoline, seasonal diesel fuels, a mixed propane and butane stream, and heavy oil products.

Lloydminster Asphalt Refinery

Our Lloydminster refinery processes heavy crude into asphalt products used in road construction and maintenance, manufactured building products, locomotive blendstock and specialty oilfield products. The refinery has a total nameplate throughput capacity of 25,000 barrels per day of heavy crude oil. It also produces a distillate stream used by the Upgrader, and a condensate stream used to blend with heavy oil production.

Ethanol Manufacturing

Husky currently produces 10 million litres per year of fuel and industrial ethanol at our plant in Minnedosa, Manitoba. A second ethanol facility in Lloydminster, Saskatchewan is currently under construction, at a cost of approximately $130 million. This plant, which is scheduled to be operational in the second quarter 2006, will have an annual capacity of 130 million litres, making it the largest ethanol plant in Western Canada. Minnedosa will be further expanded in 2007 to reach a production level of 130 million litres per year.

Husky's ethanol production supports our ''Mother Nature's Fuel'' ethanol-blended gasoline marketing program. When added to gasoline, ethanol improves fuel combustion, raises octane levels and prevents fuel line freezing, and carbon monoxide emissions, ozone precursors and net emissions of greenhouse gases. Environment Canada has designated ethanol-blended gasoline as an Environmental Choice product.

Husky's Refined Products group continues to position themselves as the leaders in ethanol-blended fuels in Western Canada.

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 us 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 us through our retail networks and to our wholesale customers. During 2005, these refiners processed an average of approximately 38.2 mbbls/day of crude oil

for us, yielding approximately 34.7 mbbls/day of refined petroleum products. During 2005, we also purchased approximately 11.2 mbbls/day of refined petroleum products from refiners and acquired approximately 6.2 mbbls/day of refined petroleum products pursuant to exchange agreements with third party refiners.

Asphalt Products

Husky produces asphalt and residual products at our 10,000 bbls/day asphalt refinery at Lloydminster and markets these products to customers across Western Canada and the northwestern and midwestern United States.

Husky has 37 percent of the market for paving asphalt sold in Western Canada our Pounder Emulsions division has a 50 percent market share in Western Canada for road application emulsion products and additional non-asphalt based road maintenance products are marketed and distributed through the Western Road Management division. We have increased sales to the United States and Eastern Canada, with 40 percent of production in 2005 exported to the United States and products shipped as far as Texas, Florida and New Brunswick. Husky plans to expand asphalt production, improve distribution, improve quality and reduce cost.

Husky also sells in excess of 5 mmbbls of asphalt cements per year. In addition, we produce and sell straight run distillates, and residuals. The distillates are a hydrogen deficient and are sold directly to the Upgrader and blended into the Husky Synthetic Blend stream. The cut is removed and re-circulated into the heavy oil pipeline network as pipeline diluent. Residuals are a blend of medium and light gas oil streams which we sell directly to customers.

Husky's asphalt distribution network consists of four emulsion/asphalt terminals located at Kamloops, British Columbia; Lethbridge, Alberta; Yorkton, Saskatchewan; and Winnipeg, Manitoba and four emulsion plants located at Edmonton, Alberta; Watson Lake, Yukon; Lloydminster and Saskatoon, Saskatchewan. Husky also utilizes an independently operated terminal at Langley, British Columbia.

All of our asphalt requirements are supplied by our Lloydminster, Alberta asphalt refinery. The refinery was designed specifically to produce asphalt from heavy crude oil at a rate of 25 mbbls/day. Debottlenecking has allowed us to increase that to 26.9 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 our average daily sales volumes of products produced at the Lloydminster refinery, for the years indicated:

	Years ended December 31,		
	2005	2004	2003
	(mbbls/day)		
Asphalt	13.8	14.0	12.9
Residual and other	8.7	8.8	9.1
	22.5	22.8	22.0

Refinery throughput averaged 25.5 mbbls/day of blended heavy crude oil feedstock during 2005. Total production of asphalt at the refinery for 2005 was down due to a planned maintenance and repair turnaround in July as well as other repairs that limited production.

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. We have 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. This has allowed us to run at or near full capacity year round.

Our strategy with respect to our asphalt marketing business is to increase sales volumes by increasing asphalt supply and developing new product streams, to enhance margins by soliciting industry for Husky ideal specifications, to minimize costs and expand our income base through new products and new markets and to pursue mergers, acquisitions, brokering and processing opportunities within our niche markets.

Some of the focus areas in 2006 will include identifying acquisition, merger, brokering, terminalling, and processing opportunities, increasing residual sales relative to diluents and tops to enhance margins, focusing on sales of higher quality products with larger margins, developing new sales tools and programs to improve customer service and satisfaction and developing new products and improving existing products.

Human Resources

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

	December 31,	
	2005	2004
Upstream	2,019	1,822
Midstream	367	347
Refined Products	385	358
Corporate and business support	518	505
	3,289	3,032

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:

	2005	2004	2003
Cash dividends declared per common share	$1.65	$1.00	$1.38

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 paid a quarterly dividend of $0.09 ($0.36 annually) per common share. From August 2003 to July 2004, Husky paid $0.10 ($0.40 annually) per common share. The dividend policy was reviewed by the Board in April 2004 and the quarterly dividend was increased to $0.12 ($0.48 annually) per common share. The dividend policy was again reviewed in April 2005 and increased to $0.14 ($0.56 annually) and again in October 2005 when it was increased to $0.25 ($1.00 annually). The Board declared special cash dividends in the amount of $1.00 per common share in July, 2003 and $0.54 per common share in November, 2004. In October 2005 the Board declared a special dividend amounting to $1.00 per common share. 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 Summary

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Stable	August 29, 2005	—
Senior Unsecured Debt	Baa2	August 29, 2005	April 25, 2001
U.S. Senior Secured Bonds	Baa2	April 30, 2004	April 25, 2001
Capital Securities	Ba1	August 29, 2005	April 25, 2001
Standard and Poor's:			
Outlook	Positive	September 12, 2005	October 3, 2002
Senior Unsecured Debt	BBB	September 12, 2005	—
U.S. Senior Secured Bonds	BBB	August 24, 2005	—
Capital Securities	BB+	September 12, 2005	—
Dominion Bond Rating Service:			
Trend	Stable	May 13, 2005	—
Senior Unsecured Debt	BBB(high)	May 13, 2005	—
Capital Securities	BBB	May 13, 2005	
Fitch:			
Outlook	Stable	July 22, 2005	—
Senior Unsecured Debt	BBB+	July 22, 2005	—
U.S. Senior Secured Bonds	A–	July 22, 2005	
Capital Securities	BBB–	July 22, 2005	—

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities. The credit ratings accorded to Husky's securities by the rating agencies are not recommendations to purchase, hold or sell the securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

Moody's

Moody's credit rating system ranges from Aaa (highest) to C (lowest). Debt securities rated within the Baa category are considered medium grade debts; they are neither highly protected nor poorly secured. Interest payments and principal security appears to be adequate at the time of the rating however they are subject to potential adverse circumstances over time. As a result these debt securities possess some speculative characteristics. The addition of a 1, 2 or 3 modifier indicates an additional relative standing within the general rating classification. The addition of the modifier 1 indicates the debt is positioned in the top one third of the general rating classification, 2 indicates the mid one third and 3 indicates the bottom one third.

Standard and Poor's

Standard and Poor's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category are considered to possess adequate protection parameters. However, they could potentially change subject to adverse economic conditions or other circumstances that may result in reduced capacity of the debtor to continue to meet principal and interest payments. As a result these debt securities possess some speculative characteristics. The addition of the modifier + or – indicates the debt is positioned above (+) or below (–) the mid range of the general category.

Dominion Bond Rating Service

Dominion Bond Rating Service's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category are considered to be of adequate credit quality. Protection of interest and principal is considered acceptable, but the debtor is susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the debtor and its rated debt. The addition of the high or low modifier denotes that the rating is either above or below the mid range of the general rating category.

Fitch

Fitch's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category indicate that there is currently a low expectation of credit risk. The capacity for timely payment of financial commitments is considered adequate, but adverse changes in circumstances or in economic conditions are more likely to impair this capacity. The addition of the modifier + or – indicates the debt is positioned above (+) or below (–) the mid range of the general category. The A category denotes that the debtor's capacity with regard to the rated debt is strong rather than adequate.

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, 2005:

	High	Low	Volume (000's)
January	34.90	32.50	11,845
February	37.65	32.30	20,225
March	40.49	35.89	14,300
April	38.84	35.12	16,441
May	42.30	36.65	12,283
June	50.75	42.00	18,264
July	53.35	47.37	11,386
August	62.00	53.50	11,413
September	69.95	59.00	11,722
October	65.79	50.50	15,936
November	59.95	53.63	11,028
December	61.60	55.58	11,767

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 and project management 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. Mr. Li has been a Director and Chairman of CK Life Sciences Int'l., (Holdings) Inc. (a biotechnology company) since 2002 and has held the following positions for more than five years: a Director and Chairman of Cheung Kong Infrastructure Holdings Limited (an infrastructure development company), an Executive Director of Hongkong Electric Holdings Limited (a holding company). Mr. Li is also a Director of The Hongkong and Shanghai Banking Corporation Limited. Mr. Li is a member of the Standing Committee of the 10th National Committee of the Chinese People's Political Consultative Conference of the People's Republic of China and he is also a member of the Executive Committee of the Commission on Strategic Development and the Economic and Employment Council 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 a Director and Chairman of Hutchison Telecommunications International Limited (an investment holding company) since 2004. Mr. Fok has held the following positions for more than five years: a Director and since 2002, Chairman of Hutchison Harbour Ring Limited (an investment holding company), a Director and Chairman of Hutchison Telecommunications (Australia) Limited (a telecommunications company), and Partner Communications Company Ltd. (a telecommunications company), Deputy

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
			Chairman and a Director of Cheung Kong Infrastructure Holdings Limited and a Director, and since November 2005 Chairman of 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 is also a Non Executive Director of Panvas Gas Holdings Limited. Mr. Fok was a director of Voice Stream Wireless Corporation from 1998 - 2001 and Hanny Holdings Limited from 1992 - 2005. 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. Mr. Fullerton has been a Director of Asia Satellite Telecommunications Holdings Limited since 1996. Mr. Fullerton was a director of George Weston Limited (a holding company) from 1991 to 2005, of Partner Communications Ltd. from 2003 to 2005, of CIBC from 1974 to 2004, of Hollinger Inc. from 1992 to 2003, of Westcoast Energy Inc. from 1993 to 2003 and of IBM Canada Ltd. from 1982 to 2001.
Glynn, Martin J.G. New York, New York U.S.A.	Director	August 25, 2000	President and Chief Executive Officer of HSBC Bank USA N.A. 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 is also a director of Wells Fargo HSBC Trade Bank N.A. and Group General Manager of HSBC Holdings plc.
Hui, Terence C.Y. Vancouver, British Columbia Canada	Director	August 25, 2000	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 and of Coopers Park Real Estate Corporation since 2005. Mr. Hui was President and Chief Executive Officer of Pacific Place Developments Corp. (a real estate

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
			development company) from 1992 to 2001. Mr. Hui has been a director of abc Multiactive Limited (a software company) since 1995.
Kinney, Brent D. Dubai, United Arab Emirates	Director	August 25, 2000	Mr. Kinney has been a director and Chief Executive Officer of Sky Petroleum Inc. since 2005. Mr. Kinney has been a director of Dragon Oil plc since 2001, of Western Silver Corporation (a mineral exploration company) since 2005 and of Benchmark Energy Ltd. since 2005. Mr. Kinney was also a director of Aurado Energy Inc. from 2003 to 2004.
Kluge, Holger Toronto, Ontario Canada	Director	August 25, 2000	Corporate Director. Mr. Kluge has been a director of Hongkong Electric Holdings Limited since 1999, of Hutchison Whampoa Limited since 2004 and of Shoppers Drug Mart since 2006. Mr. Kluge was a director of Hutchison Telecommunications (Australia) Limited from 1999 to 2005, of TOM Group Limited (formerly TOM.COM LIMITED) from 2000 to 2005, and of Loring Ward International Limited (a financial planning company) from 2004 to 2005. 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. since 1998.
Kwok, Eva L. Vancouver, British Columbia Canada	Director	August 25, 2000	Chairman, a director and Chief Executive Officer of Amara International Investment Corp. (an investment holding company) since 1992 and President from 1992 to 1996. Mrs. Kwok has been a director of Bank of Montreal Group of Companies since 1999, of CK Life Sciences Int'l., (Holdings) Inc. since 2002, Cheung Kong Infrastructure Holdings Limited and Shoppers Drug Mart since 2004 and of the Li Ka Shing (Canada) Foundation since 2005. Mrs. Kwok was a director of Air Canada from 1998 to 2003 and of Telesystem International Wireless Inc. from 2002 to 2003.
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 President since 1999 of Amara International Investment Corp. Mr. Kwok is a director of Cheung Kong (Holdings) Limited and CTC Bank of Canada.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
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.
Shaw, Wayne E. Toronto, Ontario Canada	Director	August 25, 2000	Senior Partner, Stikeman Elliott LLP, Barristers and Solicitors.
Shurniak, William Limerick, Saskatchewan Canada	Deputy Chairman and Director	August 25, 2000	Director and chairman of Northern Gas Networks Limited (a distributor of natural gas in Northern England) since 2005 and a director of Hutchison Whampoa Limited since 1984. Mr. Shurniak held the following positions until his return to Canada in 2005: 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 2002, a director of Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002, and of Lane Cove Tunnel Company Pty Ltd. (an infrastructure and transportation company) since 2004. 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 has been the Chairman and Director of TOM Online Inc., and a Director of Hutchison Telecommunications International Limited since 2004. Mr. Sixt has held the following positions for more than five years: Chairman and Director of TOM Group Limited, 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 VoiceStream 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
Ingram, Donald R. Calgary, Alberta	Senior Vice President, Midstream & Refined Products	Senior Vice President, Midstream and Refined Products of Husky since August 2000.
Girgulis, James D. Calgary, Alberta	Vice President, Legal & Corporate Secretary	Vice President, Legal & Corporate Secretary of Husky since August 2000.

The Board of Directors has an Audit Committee (as required by the *Business Corporations Act* (Alberta)) currently consisting of R.D. Fullerton (Chair), M.J.G. Glynn, T.C.Y. Hui, 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 28, 2006, the directors and officers of Husky, as a group, owned beneficially, directly or indirectly, or exercised control or direction over 397,108 common shares of Husky representing less than 1 percent 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 Orders or Bankruptcies

None of those persons who are directors or officers of the Company is or has been within the past ten years, a director or officer of any company, including the Company, 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 Company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or was subject to an event that resulted, after the director or officer ceased to be a director or officer, in the company being subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or within a year of that person ceasing to act in that capacity became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manger or trustee appointed to hold its assets, 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). In addition, Holger Kluge and Frank Sixt were directors until April 12, 2002 of vLinx Inc., a private Canadian company which was petitioned into bankruptcy on April 15, 2002. vLinx Inc. developed technology and software to facilitate international trade. Mr. Fok acted as a non-executive director of Peregrine Investments Holdings Limited (an investment bank) which was put into compulsory liquidation on March 18, 1998.

Individual Penalties, Sanctions or Bankruptcies

None of the persons who are directors or officers of the Company have, within the past ten years made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold his assets.

None of the persons who are directors or officers of the Company have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The members of Husky's Audit Committee are R.D. Fullerton (Chair), M.J.G. Glynn, T.C.Y. Hui and W.E. Shaw. Each of the members of the Company's Audit Committee (the ''Committee'') are independent in that each member does not have a direct or indirect material relationship with the Company. Multilateral Instrument 52-110 — Audit Committees provides that a material relationship is a relationship which could, in the view of the board of directors of Husky (the ''Board''), reasonably interfere with the exercise of a member's independent judgment.

The Committee's Charter provides that the Committee is to be comprised of at least three (3) members of the Board, all of whom shall be independent and meet the financial literacy requirements of applicable laws and regulations. Each member of the Committee is financially literate in that each has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

The education and experience of each Audit Committee member that is relevant to the performance of his responsibilities as an Audit Committee member is as follows.

R.D. Fullerton (Chair) — Before his retirement Mr. Fullerton served as Chief Executive Officer of CIBC and also served as a director and/or an Audit Committee member of 16 major domestic and international public companies as well as director of a number of affiliates of CIBC.

T.C.Y. Hui — Mr. Hui is the President and Chief Executive Officer of Concord Pacific Group Inc. which three years ago was a public company.

M.J.G. Glynn — Mr. Glynn is currently the Chief Executive Officer of HSBC Bank USA and prior thereto served as Chief Executive Officer of HSBC Bank Canada.

W.E. Shaw — Mr. Shaw is a senior partner of a major Canadian law firm and in that capacity has developed general business knowledge.

Husky's Audit Committee Charter is attached hereto as Schedule ''A''.

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by KPMG LLP, the Company's external auditor, during fiscal years indicated:

	Aggregate Fees Billed by the External Auditor	
	2005	2004
	($ thousands)	
Audit fees	447	805
Audit-related fees	27	207
Tax fees	160	144
All other fees	476	45
	1,110	1,201

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

Audit-Related Fees. Audit-related services included attest services not required by statute or regulation and services with respect to acquisitions and dispositions.

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

All Other Fees. Other services provided by the Company's external auditor, other than audit, audit-related and tax services, included advisory services associated with various aspects of the Sarbanes-Oxley Act of 2002.

The Company'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 to approve fees, in connection therewith. The Audit Committee approved all of the audit-related, tax and other services provided by KPMG LLP in 2005.

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.

Up to and effective July 13, 2004, the Company leased 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 is also a director and officer 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 an amended and restated lease for a term ending August 31, 2013 with Western Canadian Place Ltd. on commercial terms consistent with those for leases of comparable space in Class A office buildings in Calgary. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party.

The Company has entered into a management agreement effective July 15, 2004 with Western Canadian Place Ltd. for general management of Western Canadian Place Ltd.'s leasehold interest in office space at 635 – 8th Avenue S.W., Calgary, Alberta. The Company was paid fees of $129,547.03 in 2005 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).

INTERESTS OF EXPERTS

Certain information relating to the Company's reserves included in this Annual Information Form has been calculated by the Company and audited and opined upon as of December 31, 2005 by McDaniel & Associates Consultants Ltd. (''McDaniel''), independent petroleum engineering consultants retained by Husky, and has been so included in reliance on the opinion and analysis of McDaniel, given upon the authority of said firm as experts in reserve engineering. The partners of McDaniel as a group beneficially own, directly or indirectly, less than 1 percent of the Company's securities of any class.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal shareholders of Husky's common shares and a description of options to purchase common shares is contained in Husky's Management Information Circular dated March 14, 2006, prepared in connection with the annual and special meeting of shareholders to be held on April 19, 2006.

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, 2005, contained in Husky's 2005 Annual Report.

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

ABBREVIATIONS AND GLOSSARY OF TERMS

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
COGEH	— Canadian Oil and Gas Evaluation Handbook
FASB	— Financial Accounting Standards Board
FPSO	— floating production, storage and offloading vessel
LLB	— Lloydminster Blend
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

Barrel

A unit of volume equal to 42 U.S. gallons.

Bitumen

A highly viscous oil which is too thick to flow in its native state, and which cannot be produced without altering its viscosity. The density of bitumen is generally less than 10 degrees API.

Bulk Terminal

A facility used primarily for the storage and/or marketing of petroleum products.

Coal Bed Methane

The primary energy source of natural gas is methane (CH(4)). Coal bed methane is methane found and recovered from the coal bed seams. The methane is normally trapped in the coal by water that is under pressure. When the water is removed the methane is released.

Cold Production

A non-thermal production process for heavy oil in unconsolidated sand formations. During the cold production process heavy oil and sand are produced simultaneously through the use of progressive cavity pumps, which produce high pressure in the reservoir.

Debottlenecking

To remove restrictions thus improving flow rates and productive capacity.

Degrees API Gravity

Measure of oil density or specific gravity used in the petroleum industry. The American Petroleum Institute (API) scale expresses density such that the greater the density of the petroleum, the lower the degree of API gravity.

Delineation Well

A well in close proximity to an oil or gas well that helps determine the areal extent of the reservoir.

Developed Area

A drainage unit having a well completed thereon capable of producing oil or gas in paying quantities.

Development Well

A well drilled within the proved area of an oil and gas reservoir to the depth of a stratigraphic horizon known to be productive.

Diluent

A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to improve the transmissibility of the oil through a pipeline.

Dry and Abandoned Well

A well found to be incapable of producing oil or gas in sufficient quantities to justify completion as a producing oil or gas well.

Enhanced Recovery

The increased recovery from a crude oil pool achieved by artificial means or by the application of energy extrinsic to the pool, which artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of aiding in the lifting of fluids in the well, or stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means.

Exploration Licence

A licence with respect to the Canadian offshore or the Northwest or Yukon Territories conferring the right to explore for, and the exclusive right to drill and test for, petroleum; the exclusive right to develop the applicable area in order to produce petroleum; and, subject to satisfying the requirements for issuance of a production licence and compliance with the terms of the licence and other provisions of the relevant legislation, the exclusive right to obtain a production licence.

Exploratory Well

A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well as those items are defined herein.

Field

An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Gathering System

Pipeline system and associated facilities used to gather natural gas or crude oil from various wells and deliver it to a central point where it can be moved from there by a single pipeline to a processing facility or sales point.

Horizontal Drilling

Drilling horizontally rather than vertically through a reservoir, thereby exposing more of the well to the reservoir and increasing production.

Hydrogen Sulphide

A poisonous gas which is colourless and heavier than air and is found in sour gas.

Infill Well

A well drilled on an irregular pattern disregarding normal spacing requirements. These wells are drilled to produce from parts of a reservoir that would otherwise not be recovered through existing wells drilled in accordance with normal spacing.

Liquefied Petroleum Gas

Liquefied propanes and butanes, separately or in mixtures.

Miscible Flood

An enhanced recovery method which requires that three fluids exist in the reservoir: the mobile oil to be recovered, a displacing fluid (NGL) injected to move as a bank behind the oil, and a fluid injected to propel the displacing fluid (chase gas) through the reservoir.

Multiple Completion Well

A well producing from two or more formations by means of separate tubing strings run inside the casing, each of which carry hydrocarbons from a separate and distinct producing formation.

Natural Gas Liquids (''NGL'')

Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and condensate, or a combination thereof.

Oil Battery

An accessible area to accommodate separators, treaters, storage tanks and other equipment necessary to process and store crude oil and other fluids prior to transportation.

Oil Sands

Sands and other rock materials which contain crude bitumen and includes all other mineral substances in association therewith.

Overriding Royalty Interests

An interest acquired or withheld in the oil and gas produced (or the proceeds from the sale of such oil and gas), received free and clear of all costs of development, operation, or maintenance and in additional to the usual landowner's royalty reserved to the lessor in an oil and gas lease.

Primary Recovery

The oil and gas recovered by any method that may be employed to produce the oil or gas through a single well bore; the fluid enters the well bore by the action of native reservoir energy or gravity.

Production Sharing Contract

A contract for the development of resources under which the contractor's costs (investment) are recoverable each year out of the production but there is a maximum amount of production which can be applied to the cost recovery in any year. This annual allocation of production is referred to as cost oil, the remainder is referred to as profit oil and is divided in accordance with the contract between the contractor and the host government.

Raw Gas

Gas as produced from a well before the separation therefrom of liquefiable hydrocarbons or other substances contained therein.

Recoverable Oil-in-place

The total original oil-in-place which can be expected to be recovered. This quantity is dependent upon recovery efficiency and the economics of operation.

Secondary Recovery

Oil or gas recovered by injecting water or gas into the reservoir to force additional oil to the producing wells. Usually, but not necessarily, this is done after the primary recovery phase has passed.

Seismic (Survey)

A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations. The rate at which the waves are transmitted varies with the medium through which they pass.

Service Well

A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation or injection for in-situ combustion.

Significant Discovery Licence

A licence with respect to the Canadian offshore or the Northwest Territories or Yukon conferring the right to explore for, and the exclusive right to drill and test for, petroleum; the exclusive right to develop the applicable area in order to produce petroleum; and, subject to satisfying the requirements for issuance of a production licence and compliance with other provisions of the relevant legislation, the exclusive right to obtain a production licence.

Sour Gas

Natural gas contaminated with chemical impurities, notably hydrogen sulphide or other sulphur compounds. Such compounds must be removed before the gas can be used for commercial or domestic purposes.

Specific Gravity

The ratio between the weight of equal volumes of water and another liquid measured at standard temperature, where the weight of water is assigned a value of one (1). However, the specific gravity of oil is normally expressed in degrees of API gravity as follows:

$$\text{Degrees API} = \frac{141.5}{\text{Specific gravity @ F60 degrees}} - 13.5$$

Spot Price

The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased ''on the spot'' at current market rates.

Steam Assisted Gravity Drainage

A recovery method used to produce heavy crude oil and bitumen in-situ. Steam is injected via a horizontal well along a producing formation. The temperature in the formation increases and lowers the viscosity of the crude oil allowing it to fall to a horizontal production well beneath the steam injection well.

Step-out Well

A well drilled adjacent to a proven well but located in an unproven area; a well drilled in an effort to ascertain the extent and boundaries of a producing formation.

Straight Run

A term used to describe any refined product that emerges from the initial distillation of crude oil.

Stratigraphic Test Well

A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) ''exploratory-type'', if not drilled in a proved area, or (ii) ''development-type'', if drilled in a proved area.

Synthetic Oil

A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content.

Tertiary Recovery

The recovery of oil and gas by using exotic or complex recovery schemes involving steam, chemicals, gases or heat. Usually, but not necessarily, this is done after the secondary recovery phase has passed.

Three-D Seismic (Survey)

Three dimensional seismic imaging which uses a grid of numerous cable rather than a few lines stretched in one line.

Turnaround

Perform maintenance at a plant or facility which requires the plant or facility to be shut down for the duration.

Undeveloped Area

An area in which it has not been established by drilling operations whether oil and/or gas may be found in commercial quantities.

Waterflood

One method of secondary recovery in which water is injected into an oil reservoir for the purpose of forcing oil out of the reservoir and into the bore of a producing well.

Well Abandonment Costs

Costs of abandoning a well (net of any salvage value) and of disconnecting the well from the surface gathering system.

Wellhead

The structure, sometimes called the ''Christmas tree'', that is positioned on the surface over a well that is used to control the flow of oil or gas as it emerges from the sub surface casinghead.

Working Interest

An interest in the net revenues of an oil and gas property which is proportionate to the share of exploration and development costs borne until such costs have been recovered, and which entitles the holder to participate in a share of net revenue thereafter.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Information Form are forward-looking statements or information, (collectively ''forward-looking statements''), within the meaning of applicable Canadian securities legislation, and 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,'' ''intend,'' ''plan,'' ''projection'' ''could''; ''vision''; ''goals''; ''objective'' 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. In particular, our construction plans for the Tucker in-situ oil sands project, Lloydminster Ethanol Plant and the Minnedosa Ethanol Plant; our plans to debottleneck the Lloydminster Upgrader; our plans to expand our oil pipeline systems; our design plans for the Sunrise in-situ oil sands project; our exploration and development drilling plans for Western Canada and the Northwest Territories; our South and east China Seas exploration drilling plans; our estimates of the productive capacity for White Rose, Tucker and Sunrise; our production forecasts; our plans to develop our Madura Stait PSC; and statements relating to declining production in the Western Canada Sedimentary Basin and increasing non-conventional production, are forward-looking statements.

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

- fluctuations in commodity prices
- the accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- changes in general economic, market and business conditions
- fluctuations in supply and demand for our products
- fluctuations in the cost of borrowing
- our use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and 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 we operate
- our ability to receive timely regulatory approvals
- the integrity and reliability of our capital assets
- the cumulative impact of other resource development projects
- the 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
- actions by governmental authorities, including changes in environmental and other regulations that may impose restriction in areas where we operate
- the ability and willingness of parties with whom we have material relationships to fulfill their obligations

- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable
- such other risks, uncertainties and other factors described from time to time in Husky's reports and filings with Canadian securities authorities and with the SEC.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, 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. 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.

Schedule A

AIF

HUSKY ENERGY INC.

Audit Committee Charter

The Audit Committee (the ''Committee'') of the Board of Directors (the ''Board'') of Husky Energy Inc. (the ''Company'') will have the oversight responsibility, authority and specific duties as described below.

Composition

The Committee will be comprised of three or more directors as determined by the Board, each of whom shall satisfy the independence and financial literacy requirements of applicable securities regulatory requirements. In addition, one of the members of the Committee will be an audit committee financial expert as defined in applicable securities regulatory requirements. The members of the Committee will be elected annually at the organizational meeting of the full Board on the recommendation of the Corporate Governance Committee to the Co-Chairmen and will be listed in the annual report to shareholders. One of the members of the Committee will be elected Committee Chair by the Board.

Responsibility

The Committee is a part of the Board. Its primary function is to assist the Board in fulfilling its oversight responsibilities with respect to:

(i) the quarterly and annual financial statements and quarterly and annual MD&A be provided to shareholders and the appropriate regulatory agencies;

(ii) earnings press releases before the Company publicly discloses this information;

(iii) the system of internal controls that management has established;

(iv) the internal and external audit process;

(v) the appointment of qualified reserves evaluators or auditors; and

(vi) the filing of statements and reports with respect to the Company's oil and gas reserves.

In addition, the Committee provides an avenue for communication between the Board and each of internal audit, the external auditors, financial management, external qualified reserves evaluators or auditors and internal qualified reserves evaluators. The Committee should have a clear understanding with the external auditors and the external reserve evaluators or auditors that an open and transparent relationship must be maintained with the Committee.

The Committee will make regular reports to the Board concerning its activities.

While the Audit Committee has the responsibilities and powers set forth in this Charter, the role of the Audit committee is oversight. The members of the Committee are not full time employees of the Company and may or may not be accountants or auditors by profession or experts in the fields of accounting or auditing and, in any event, do not serve in such capacity. Consequently, it is not the duty of the Audit Committee to plan or conduct audits or to determine that the Company's financial statements are complete and accurate and are in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors and, as to reserves, the external reserve evaluators or auditors. Management and the external auditors shall also have the responsibility to conduct investigations and to assure compliance with laws and regulations and the Company's business conduct guidelines.

Authority

Subject to the prior approval of the Board, the Committee is granted the authority to investigate any matter or activity involving financial accounting and financial reporting, the internal controls of the Company and the reporting of the Company's reserves and oil and gas activities.

The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any advisors employed by the Committee.

In recognition of the fact that the independent auditors are ultimately accountable to the Committee, the Committee shall have the authority and responsibility to nominate for shareholder approval, evaluate and, where appropriate, replace the independent auditors and shall approve all audit engagement fees and terms and all non-audit engagements with the independent auditors. The Committee shall consult with management and the internal audit group but shall not delegate these responsibilities.

Meetings

The Committee is to meet at least four times annually and as many additional times as the Committee deems necessary. Committee members will strive to be present at all meetings either in person or by telephone. As necessary or desirable, but in any case at least quarterly, the Committee shall meet with members of management and representatives of the external auditors and internal audit in separate executive sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately. Likewise, as necessary or desirable, but in any case at least annually, the Committee shall meet the management and representatives of the external reserve evaluators or auditors and internal reserves evaluators in separate executive sessions to discuss matters that the Committee or any of these groups believes should be discussed privately.

Specific Duties

In carrying out its oversight responsibilities, the Committee will:

1. Review and reassess the adequacy of this Charter annually and recommend any proposed changes to the Board for approval.
2. (a) Review with the Company's management, internal audit and external auditors and recommend to the Board for approval the Company's annual financial statements and annual MD&A which is to be provided to shareholders and the appropriate regulatory agencies, including any financial statement contained in a prospectus, information circular, registration statement or other similar document.

   (b) Review with the Company's management, internal audit and external auditors and approve the Company's quarterly financial statements and quarterly MD&A which is to be provided to shareholders and the appropriate regulatory agencies.
3. Review with the Company's management and approve earnings press releases before the Company publicly discloses this information.
4. Recommend to the Board the external auditors to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attest services and the compensation to be paid to the external auditors. The external auditors shall report directly to the Committee.
5. Be directly responsible for the oversight of the work of the external auditors, including the resolution of disagreements between management of the Company and the external auditors regarding financial reporting.
6. Review with the Company's management, internal audit and external auditors the Company's accounting and financial reporting controls. Obtain annually in writing from the external auditors their observations, if any, on significant weaknesses in internal controls as noted during the course of their work.
7. Review with the Company's management, internal audit and external auditor's significant accounting and reporting principles, practices and procedures applied by the Company in preparing its financial statements. Discuss with the external auditors their judgements about the quality, not just the acceptability, of the Company's accounting principles used in financial reporting.
8. Review the scope of internal audit's work plan for the year and receive a summary report of major findings by internal auditors and how management is addressing the conditions reported.
9. Review the scope and general extent of the external auditors' annual audit. The Committee's review should include an explanation from the external auditors of the factors considered in determining the audit scope, including the major risk factors. The external auditors should confirm to the Committee whether or not any limitations have been placed on the scope or nature of their audit procedures.
10. Inquire as to the independence of the external auditors and obtain from the external auditors, at least annually, a formal written statement delineating all relationships between the external auditors and the

Company as contemplated by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees.

11. Have a predetermined arrangement with the external auditors that they will advise the Committee, through its Chair and management of the Company, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Company, and that such notification is to be made prior to the related press release. Also receive a written confirmation provided by the external auditors at the end of each of the first three quarters of the year that they have nothing to report to the Committee, if that is the case, or the written enumeration of required reporting issues.

12. At the completion of the annual audit, review with management, internal audit and the external auditors the following:

    - The annual financial statements and related footnotes and financial information to be included in the Company's annual report to shareholders.
    - Results of the audit of the financial statements and the related report thereon and, if applicable, a report on changes during the year in accounting principles and their application.
    - Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit. Inquire about the cooperation received by the external auditors during their audit, including access to all requested records, data and information.
    - Inquire of the external auditors whether there have been any material disagreements with management, which, if not satisfactorily resolved, would have caused them to issue a non-standard report on the Company's financial statements.

13. Discuss with the external auditors, without management being present, (a) the quality of the Company's financial and accounting personnel, and (b) the completeness and accuracy of the Company's financial statements. Also, elicit the comments of management regarding the responsiveness of the external auditors to the Company's needs.

14. Meet with management, to discuss any relevant significant recommendations that the external auditors may have, particularly those characterized as 'material' or 'serious'. Typically, such recommendations will be presented by the external auditors in the form of a Letter of Comments and Recommendations to the Committee. The Committee should review responses of management to the Letter of Comments and Recommendations from the external auditors and receive follow-up reports on action taken concerning the aforementioned recommendations.

15. Have 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. The Committee shall also review and approve disclosures required to be included in periodic reports filed with Canadian securities regulators and the Securities and Exchange Commission with respect to non-audit services performed by external auditors.

16. Be satisfied that adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company's financial statements, and periodically assess the adequacy of those procedures.

17. Establish procedures for (a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matter, and (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

18. Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors.

19. Review the appointment and replacement of the senior internal audit executive.

20. Review with management, internal audit and the external auditors the methods used to establish and monitor the Company's policies with respect to unethical or illegal activities by Company employees that may have a material impact on the financial statements.

21. Generally as part of the review of the annual financial statements, receive a report(s), at least annually, from the Company's general counsel concerning legal, regulatory and compliance matters that may have a material impact on the financial statements.
22. Review, with reasonable frequency, the Company's procedures relating to the disclosure of information with respect to the Company's oil and gas reserves, including the Company's procedures for complying with the disclosure requirements and restrictions of applicable regulations.
23. Review with management the appointment of external qualified reserves evaluators or auditors, and in the case of any proposed change in such appointment, determine the reasons for the change and whether there have been disputes between the appointed external qualified reserves evaluators or auditors, and management.
24. Review, with reasonable frequency, the Company's procedures for providing information to the external qualified reserves evaluators or auditors who report on reserves and data for the purposes of compliance with applicable securities laws.
25. Before the approval and the release of the Company's reserves data and the report of the qualified reserve evaluators or auditors thereon, meet with management, the external qualified reserves evaluators or auditors and the internal qualified reserves evaluators to determine whether any restrictions affect their ability to report on reserves data without reservation and to review the reserves data and the report of the qualified reserves evaluators.
26. Recommend to the Board for approval the content and filing of required statements and reports relating to the Company's disclosure of reserve data as prescribed by applicable regulations.
27. Review and approve (a) any change or waiver in the Company's Code of Business Conduct for the chief executive officer and senior financial officers and (b) any public disclosure made regarding such change or waiver.

Calgary, Alberta, Canada
February 16, 2005