2010

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 40-F

☐ Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934

☒ Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2010 **Commission File Number: 001-04307**

Husky Energy Inc.
(Exact name of Registrant as specified in its charter)

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

707-8th Avenue S.W., P.O. Box 6525 Station D, Calgary, Alberta, Canada T2P 3G7
(403) 298-6111
(Address and telephone number of Registrant's principal executive office)

CT Corporation System, 111 Eighth Avenue, New York, New York 10011
(212) 894-8400
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:
Title of Class: None

Securities registered or to be registered pursuant to Section 12(g) of the Act:
Title of Class: None

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

The Registrant is a "voluntary filer" and files annual reports on Form 40-F as well as amendments to such reports and furnishes information on Form 6-K to the Securities and Exchange Commission, pursuant to its obligations under its Indentures dated June 14, 2002 and September 11, 2007 relating to its debt securities issued thereunder.

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

☒ Annual information form ☒ Audited annual financial statements

Number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 890,708,795

Common Shares outstanding as of December 31, 2010

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☐ No ☐

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

Yes ☒ No ☐

The Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the Registrant's Registration Statement under the Securities Act of 1933: Form F-9 File No. 333-157389.

Principal Documents

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

A. Annual Information Form

The Annual Information Form of Husky Energy Inc. ("Husky" or "the Company") for the year ended December 31, 2010 is included as Document A of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

Husky's audited consolidated financial statements for the years ended December 31, 2010 and December 31, 2009, including the auditors' report with respect thereto, is included as Document B of this Annual Report on Form 40-F.

C. Reconciliation to Accounting Principles Generally Accepted in the United States

The reconciliation of Husky's audited consolidated financial statements to accounting principles generally accepted in the United States is included as Document C of this Annual Report on Form 40-F.

D. Management's Discussion and Analysis

Husky's Management's Discussion and Analysis for the year ended December 31, 2010 is included as Document D of this Annual Report on Form 40-F.

Certifications

See Exhibits 23.1, 23.2, 31.1, 31.2, 32.1 and 32.2, which are included as Exhibits to this Annual Report on Form 40-F.

Supplemental Reserves Information

See Exhibit 99.1 for the Supplemental Reserves Information, which is included as an Exhibit to this Annual Report on Form 40-F.

Disclosure Controls and Procedures

See the section "Disclosure Controls and Procedures" in Husky's Management's Discussion and Analysis for the year ended December 31, 2010 which is included as Document D to this Annual Report on Form 40-F.

Management's Annual Report on Internal Control Over Financial Reporting

The required disclosure is included in the "Management's Report" that accompanies Husky's consolidated financial statements for the year ended December 31, 2010, which is included as Document B to this Annual Report on Form 40-F.

Attestation Report of the Registered Public Accounting Firm

The required disclosure is included in the "Independent Auditors' Report of Registered Public Accounting Firm" that accompanies Husky's consolidated financial statements for the year ended December 31, 2010, which is included as Document B to this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting

The required disclosure is included in the section "Controls and Procedures" in Husky's Management's Discussion and Analysis for the year ended December 31, 2010, which is included as Document D to this Annual Report on Form 40-F.

Notice Pursuant to Regulation BTR

Not Applicable.

Audit Committee Financial Expert

The Board of Directors of Husky has determined that R. Donald Fullerton is an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its Audit Committee. Pursuant to paragraph 8(a)(2) of General Instruction B to Form 40-F, the Board has applied the definition of independence applicable to the audit committee members of New York Stock Exchange listed companies. Mr. Fullerton is a corporate director and is independent under the New York Stock Exchange standard. For a description of Mr. Fullerton's relevant experience in financial matters, see Mr. Fullerton's five year history in the section "Directors and Officers" and in the section "Audit Committee"

in Husky's Annual Information Form for the year ended December 31, 2010, which is included as Document A of this Annual Report on Form 40-F.

Code of Business Conduct and Ethics

Husky's Code of Ethics is disclosed in its Code of Business Conduct, which is applicable to its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions and to all of its other employees, and is posted on its website at www.huskyenergy.com. In the fiscal year ended December 31, 2010, there have been no amendments to Husky's Code of Ethics, nor has Husky granted a waiver including an implicit waiver from a provision of its Code of Ethics. In the event that, during Husky's ensuing fiscal year, Husky:

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

ii. grants a waiver, including an implicit waiver, from a provision of its Code of Business Conduct to any of its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to one or more of the items set forth in paragraph (9)(b) of General Instruction B to Form 40-F.

Husky will promptly disclose such occurrences on its website following the date of such amendment or waiver and will specifically describe the nature of any amendment or waiver, and in the case of a waiver, name the person to whom the waiver was granted and the date of the waiver.

Principal Accountant Fees and Services

See the section "Audit Committee" in the Annual Information Form for the year ended December 31, 2010, which is included as Document A to this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements

See the section "Off-Balance Sheet Arrangements" in Husky's Management's Discussion and Analysis for the year ended December 31, 2010, which is included as Document D to this Annual Report on Form 40-F.

Tabular Disclosure of Contractual Obligations

See the section "Contractual Obligations and Other Commercial Commitments" in Husky's Management's Discussion and Analysis for the year ended December 31, 2010, which is included as Document D to this Annual Report on Form 40-F.

Identification of the Audit Committee

Husky has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: R.D. Fullerton, F.S.H Ma, G.C. Magnus, C. S. Russel and W. Shurniak.

Undertaking and Consent to Service of Process

Undertaking

Husky undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

A Form F-X signed by Husky and its agent for service of process has been filed with the Commission together with Forms F-9 (333 - 137211), (333 - 157389) and (333 - 89714) in connection with its debt securities registered on such forms.

Any change to the name or address of the agent for service of process of Husky shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of Husky.

Signatures

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

Dated this 8th day of March, 2011

Husky Energy Inc.

By: /s/ Asim Ghosh
Name: Asim Ghosh
Title: President & Chief Executive Officer

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

Document A
Form 40-F

Annual Information Form

For the Year Ended December 31, 2010

Husky Energy Inc.

Annual Information Form

For the Year Ended December 31, 2010

March 8, 2011

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

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 barrel of oil equivalent ("boe") basis using the ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("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 boe and thousands of cubic feet equivalents ("mcfge") are based on a conversion rate of six mcf to one bbl.

The Company has disclosed discovered petroleum initially-in-place in this Annual Information Form. Discovered petroleum initially-in-place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable. A recovery project cannot be defined for these volumes of discovered petroleum initially-in-place at this time. There is no certainty that it will be commercially viable to produce any portion of the resources.

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.

This Annual Information Form contains "forward-looking information and statements" within the meaning of applicable securities laws. For a full discussion of the forward-looking information and statements and the risks to which they are subject, see the "Special Note Regarding Forward-Looking Statements" in this Annual Information Form.

Cautionary Note to U.S. Investors

The United States Securities and Exchange Commission ("SEC") permits U.S. oil and gas companies, in their filings with the SEC, to separately disclose proved, probable and possible reserves that have been determined in accordance with SEC rules. Husky uses certain terms in this document, such as "discovered petroleum initially-in-place" that the SEC's guidelines strictly prohibit in filings with the SEC by U.S. oil and gas companies.

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 dollar/U.S. dollar rate of exchange or the cost of a U.S. dollar in Canadian currency for the three years indicated.

	Year ended December 31		
(Cdn $ per U.S. $)	**2010**	**2009**	**2008**
Year end	0.995	1.047	1.224
Low	0.995	1.029	0.972
High	1.078	1.300	1.297
Average	1.030	1.136	1.066

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 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" ("NI 51-101")* to involve independent qualified oil and gas reserves evaluators or auditors. Notwithstanding this exemption, we involve independent qualified reserves auditors as part of Husky's corporate governance practices. Their involvement helps assure that our internal oil and gas reserves estimates are materially correct.

In Husky's view, the reliability of Husky's internally generated oil and gas reserves data is not materially different than would be afforded by Husky involving independent qualified reserves evaluators to evaluate and review the reserves data. The primary factors supporting the involvement of independent qualified reserves evaluators 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 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.

In the past, Husky has also sought and been granted by the Canadian Securities Administrators permission to make certain disclosure of its oil and gas activities in accordance with U.S. disclosure requirements. This permission ceased to be available after January 1, 2011, although the Company received an exemption from the Canadian Securities Administrators which allows the Company to also disclose its reserves using U.S. disclosure requirements as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101.

Information to further an investor's understanding is specifically encouraged to be included in the Company's 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 Husky's Form 40-F which is filed with SEC's 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. was incorporated under the *Business Corporations Act* (Alberta) on June 21, 2000.

Husky Energy Inc. 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.

Intercorporate Relationships

The principal subsidiaries of Husky and place of incorporation, continuance or place of organization, as the case may be, are as follows.(1) All of the following companies and partnerships, except as otherwise indicated, are 100% beneficially owned or controlled or directed, directly or indirectly.

Name	Jurisdiction
Subsidiaries of Husky Energy Inc.	
Husky Oil Operations Limited ("HOOL")	Alberta
Subsidiaries of Husky Oil Operations Limited	
Husky Oil Limited Partnership	Alberta
Husky Terra Nova Partnership	Alberta
Husky Downstream General Partnership	Alberta
Husky Energy Marketing Partnership	Alberta
Sunrise Oil Sands Partnership (50%)	Alberta
BP Husky Refining LLC (50%)	Delaware
Lima Refining Company	Delaware
Husky Marketing and Supply Company	Delaware

Note:

(1) Principal operating subsidiaries exclusive of intercorporate relationships due to financing related receivables and investments.

GENERAL DEVELOPMENT OF HUSKY

Three Year History of Husky

2008

On January 18, 2008, Husky announced that it had secured the Transocean owned semi-submersible drilling rig, *GSF Grand Banks*, for continuing operations in the White Rose area and for continued delineation drilling offshore Newfoundland and Labrador. The three year agreement also includes an option for two additional one year extensions.

On March 11, 2008, Husky announced an agreement with Suncor (formerly Petro-Canada) and StatoilHydro to secure the semi-submersible drilling rig, *Henry Goodrich*, for a period of 24 to 30 months. The agreement allowed Husky to use the rig on its operated properties offshore Newfoundland and Labrador for 17 months.

On March 31, 2008, Husky announced that all necessary government and regulatory approvals had been received and the arrangements for the formation of an integrated oil sands/refining joint venture with BP had been completed. The effective date of the transaction was January 1, 2008.

On April 2, 2008, Husky announced that it had received approval from the federal and provincial governments

and regulators to proceed with the development of the North Amethyst oil field, a satellite of the South Avalon White Rose producing oil field.

On April 17, 2008, Husky announced that it had reached an agreement with China National Offshore Oil Corporation ("CNOOC") to jointly develop the Madura BD natural gas and natural gas liquids field offshore the East Java Sea, Indonesia. The agreement covers the development and further exploration of the Madura Strait Production Sharing Contract ("PSC"). CNOOC paid U.S. $125 million to acquire a 50% equity interest in Husky Oil (Madura) Ltd. ("HOML"), which holds the Madura Strait PSC.

On June 5, 2008, Husky repaid the remaining U.S. $750 million short-term bridge facility arranged in 2007 to acquire the Lima Refinery.

On June 12, 2008, Husky announced a cash tender offer to purchase any and all of its outstanding 8.90% Capital Securities. The offer was for payment of U.S. $1,010 per U.S. $1,000 principal amount plus accrued and unpaid interest. On July 11, 2008, 95% of the 8.90% Capital Securities had been validly tendered and accepted for payment. The Company subsequently redeemed all remaining 8.90% Capital Securities.

On June 25, 2008, Husky announced that it had signed a contract with CNOOC for an exploration block in the South China Sea. The 63/05 block covers approximately 1,777 sq km and is located in the Qiongdongnan Basin approximately 100 km south of Hainan Island, in less than 120m of water.

On August 29, 2008, Husky redeemed the 6.95% medium-term notes Series E at a redemption price of $208 million including accrued interest.

On September 11, 2008, Husky announced that it had acquired two parcels (Block 1 and 3) offshore Labrador, on the Labrador Shelf. Parcel NL07-2-1, Block 1, covers approximately 2,370 sq km and Parcel NL07-2-3, Block 3, covers approximately 2,337 sq km.

During 2008, Husky repurchased a total of U.S. $63 million of the outstanding U.S. $450 million 6.80% notes due September 2037.

2009

In 2009, Husky completed drilling and testing of three appraisal wells at the Liwan 3-1 field on Block 29/26, in the South China Sea.

In 2009, an application was made in the East Bawean II PSC to relinquish the block. The application was based on the drilling of two exploration wells, the Adiyasa 1 and Kukura 1, which were abandoned without testing in 2009.

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the SEC on February 27, 2009. The shelf prospectus enables Husky to offer up to U.S. $3.0 billion of debt securities in the U.S. until March 26, 2011.

On May 11, 2009, Husky issued U.S. $750 million of 5.90% notes due June 15, 2014 and U.S. $750 million of 7.25% notes due December 15, 2019 under the debt shelf prospectus filed in February 2009.

In August 2009, Husky completed scheduled maintenance of the *SeaRose FPSO.*

On October 29, 2009, Husky announced it had completed and tested two exploratory wells to evaluate the shale gas potential in the Montney and Doig formations in Northeast British Columbia, Canada.

On November 23, 2009, Husky announced the discovery of additional oil resources in the White Rose area. Analysis of results from the North Amethyst E-17 exploration well that was drilled in 2008 to the deeper Hibernia formation revealed 55 m of net oil-bearing reservoir.

On November 30, 2009, Husky announced an agreement to purchase Penn West Energy Trust heavy oil properties contained within Husky's Lloydminster area of operations in Alberta and Saskatchewan.

On December 8, 2009, Husky announced that a significant new natural gas discovery at Liuhua 34-2-1 on Block 29/26 in the South China Sea. The discovery well tested natural gas with high liquids content at an equipment restricted rate of 55 mmcf/day, with indications that future well deliveries could exceed 140 mmcf/day.

On December 10, 2009, Husky announced that it entered into an agreement with Suncor Energy Inc. and Suncor Energy Products Inc. to purchase 98 retail outlets in the Ontario market. The first site was transferred to Husky in March 2010, with the remaining sites transferred between April and November 2010.

On December 21, 2009, Husky filed a debt shelf prospectus that enables Husky to offer up to $1.0 billion of

medium term notes in Canada until January 21, 2012.

2010

On January 20, 2010, Husky announced that it has completed the front end engineering design ("FEED") for Phase I of the Sunrise Energy Project, located 60 kilometres northeast of Fort McMurray. The Company also obtained the necessary approvals from the Government of Alberta, Environment Department and the Energy Resources and Conservation Board ("ERCB") to proceed with the project. Husky later announced in November 2010 that it is moving forward with the construction of facilities for the phased development of the Sunrise oil sands lease in the Fort McMurray region of northern Alberta. This first phase will cost approximately $2.5 billion and is expected to produce about 60,000 barrels per day gross beginning in 2014. Further, Sunrise will use steam-assisted gravity drainage ("SAGD") technology which limits site disturbance. In November 2010, sanction for Phase I was announced.

On February 8, 2010, Husky announced its third significant gas discovery on Block 29/26 in the South China Sea. The Liuhua 29-1 exploration well tested natural gas at an equipment restricted rate of 57 mmcf/day, with indications that the future deliverability of the well could exceed 90 mmcf/day.

On March 9, 2010, Husky announced that it would issue $700 million in medium term notes under the $1 billion shelf prospectus which was filed by the Company in December 2009 with the securities regulatory authorities in each of the provinces of Canada. The medium term notes were issued in two tranches: $300 million at 3.75% maturing on March 12, 2015 and $400 million at 5.00% maturing on March 12, 2020. The transaction closed on March 12, 2010.

On May 21, 2010, Husky announced the appointment of Mr. Asim Ghosh as President and Chief Executive Officer of the Company, effective June 1, 2010. Mr. Ghosh was previously appointed to the Husky Board of Directors in May, 2009. The Company's former President and Chief Executive Officer, Mr. John C.S. Lau, was appointed President and Chief Executive Officer, Asia Pacific, in May 2010 after stepping down as President and Chief Executive Officer of Husky Energy Inc. after 18 years in the position.

On May 31, 2010, Husky completed drilling and successful testing of the first appraisal well at the Liuhua 29-1 discovery Block 29/26 in the South China Sea with encouraging results. The well tested natural gas at an equipment restricted rate of 55 mmcf per day with indications that the well's future deliverability could be 60 – 70 mmcf per day.

On May 31, 2010, Husky also announced that oil production had been achieved from the North Amethyst field, offshore Newfoundland & Labrador. North Amethyst is the first satellite field development at Husky's White Rose project and was brought on production less than four years after discovery. It is also the first subsea tieback project in Canada.

On September 1, 2010, Husky announced that a purchase agreement had been signed to acquire natural gas properties in west central Alberta, which added 10.8 mboe/day of production, 32.6 mmboe of proven reserves and 10.8 mmboe of probable reserves, and extended the optimum utilization of its Ram River gas plant. The acquisition also added 160,000 acres of land to the Company's holdings, including 122,000 undeveloped acres, doubling Husky's current land holdings in the region. This purchase closed on November 30, 2010 and has an effective date of June 1, 2010. The reserve estimates are as at December 31, 2010.

On October 27, 2010, Husky announced that it had completed the successful drilling of a second appraisal well at the Liuhua 29-1 discovery Block 29/26 in the South China Sea. Core and log data has verified the presence of approximately 60 metres of gas pay. Additional appraisal drilling will be undertaken to further define the resource size and prepare the Plan of Development for the field once the well data has been integrated.

On October 28, 2010, Husky announced that it had received approval from the Government of Indonesia for a 20 year extension to the existing Madura Strait PSC, originally awarded in 1982. The Madura Strait PSC includes the Madura BD and MDA fields, as well as numerous other prospects and leads. Husky and its partner in the Madura Strait also agreed to sell a 10% equity stake each, in HOML to Samudra Energy Ltd., through its affiliate SMS Development Ltd. Following the completion of the sale, Husky and CNOOC respectively hold a 40% equity interest in HOML, with the 20% balance held by Samudra Energy Ltd. This sale closed on January 13, 2011.

Effective November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada. The shelf prospectus enables Husky to offer up to $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in Canada until December 2012.

On November 29, 2010, Husky announced several strategic initiatives intended to accelerate near-term

production and reserve growth and to secure its medium and long-term growth opportunities and approved a $4.86 billion capital program in 2011.

As part of this capital program to support near-term growth, Husky signed an $860 million purchase and sale agreement with ExxonMobil Canada Ltd. to acquire oil and natural gas properties in Alberta and northeast British Columbia. This purchase included 16.3 mboe/day of natural gas production, 4.8 mboe/day of oil production, and 0.8 mboe/day of natural gas liquids. Husky's reserve estimate is 104 mmboe of proved reserves and nine mmboe of probable reserves based on an effective date of December 1, 2010. The purchase transaction closed on February 4, 2011.

Husky also announced that it has decided to retain its South East Asia assets citing the Company's view that it is in the best interest of the shareholders to continue to build this material business in the resource-rich region and leverage the close proximity to major energy markets in Hong Kong and Mainland China.

Husky has also made progress in advancing the Liwan 3-1 natural gas project in the South China Sea. The Government of China has approved the Original-Gas-in-Place (OGIP) report for the Liwan 3-1 field. Tendering for major equipment and facilities is underway and key contracts are expected to be awarded in the near term in order to achieve first gas production in late 2013.

To support its strategic growth initiatives, on December 7, 2010 Husky issued equity by way of a public overnight-marketed common share offering and a private placement to its principal shareholders. Pursuant to the public offering, the Company issued a total of 11.9 million common shares at a price of $24.50 per share for total gross proceeds of approximately $293 million. The public offering was conducted under the Company's previously filed shelf prospectus and supplement to the shelf prospectus. The Company also issued a total of 28.9 million common shares to the principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for a total gross proceeds of approximately $707 million via private placement. The public offering and private placement closed on December 7, 2010.

On December 7, 2010, Husky announced that it has signed a Heads of Agreement with CNOOC, specifying the key principles of cooperation for funding and operation of the Liwan 3-1 deep water gas field development. Under the agreement for the Liwan 3-1 field development, Husky will operate the deep water portion of the project involving development drilling and completions, subsea equipment and controls, and subsea tie-backs to a shallow water platform. CNOOC will operate the shallow water portion of the project including a shallow water platform, approximately 270 km subsea pipeline to shore, and the onshore gas processing plant. Husky continues to hold 49% working interest for Liwan 3-1. First gas from the Liwan 3-1 development is anticipated in late 2013, ramping up through 2014.

Subsequent Events

Sale of Alberta Oil Sands Leases

On January 14, 2011, Husky completed a sales agreement to sell 23 square miles of mining leases in Alberta for a consideration of $200 million.

Sale of Meridian Cogeneration Facility

Husky holds a 50% interest in the Meridian cogeneration facility, a 215 MW natural gas fired cogeneration facility at the site of the Lloydminster Upgrader. TransAlta Cogeneration, L.P. ("TACLP") is the Company's joint venture partner for the Meridian cogeneration facility. In February 2011, Husky and TACLP agreed to sell the cogeneration facility to an indirect wholly owned subsidiary of Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited. Completion of the transaction is subject to consent from Saskatchewan Power Corporation as well as regulatory approval. The transaction is expected to be completed by April 2011.

Special Meeting of Shareholders

On February 28, 2011, Husky's shareholders approved amendments to Husky's common share terms, which provides the shareholders with the ability to receive dividends in common shares or in cash. See "Dividends".

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. During 2009, production of bitumen from oil sands increased by approximately 14% compared with 2008 but was almost entirely offset by decreased production of conventional crude oil including production from the Atlantic Region. As a result production of crude oil, including bitumen and synthetic crude oil, was less than 1% higher in 2009 than in 2008. From 2000 to 2009, production replacement in Canada averaged 88% [(1)]. Oil sands production currently accounts for 55% of Western Canada's total crude oil production. In its June 2010 forecast the Canadian Association of Petroleum Producers ("CAPP") project total Canadian production increasing by approximately 70% to 4.3 mmbbls/day by 2025. Production above 3.0 mmbbls/day comes from new oil sands projects that were not under construction at the forecast date. CAPP forecasts that the decline in conventional crude oil production, which has been declining for years, will slow with the application of new technologies in resource plays such as the Cardium and Bakken formations and the introduction of new incentives from the Alberta Government [(2).]

Natural gas production has declined with low natural gas prices. Lower prices resulted from increased supply from non-conventional sources and lower economic activity in the United States. Natural gas markets are expected to remain well supplied in the near-term. As a result, investment in natural gas exploration and development is expected to be focused on resource plays that utilize new technology and are in natural gas liquid prone areas[(3)]. Conventional natural gas exploration continues to be focused on the traditionally less accessible areas in the overthrust belt along the eastern slope of the Rocky Mountains.

The trend of volatile commodity prices 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 of energy. As a result of numerous supply disruptions and increased demand from emerging economies oil prices reached historic highs in 2008. Notwithstanding supply disruptions or major policy changes in respect of greenhouse gas emissions, recent forecasts [(4)] by the Energy Information Administration ("EIA") in the United States include significant long-term potential for increased crude oil supply from producers outside of the Organization of the Petroleum Exporting Countries ("OPEC") over the next two and half decades, particularly conventional production from Brazil, Russia, and Kazakhstan. With higher prices supporting economic viability, Canada's oil sands production could reach 5.1 mmbbls/day in 2035. World oil prices declined in the second half of 2008 from their mid-July peak then trended up in 2009 and 2010. By mid February 2011, WTI spot prices had averaged U.S. $88/bbl and Brent spot averaged U.S. $98/bbl. The EIA's reference case forecast prices gradually rise as the world economy recovers and global demand grows more rapidly than crude oil supplies from non-OPEC producers.

The EIA short-term energy outlook[(5)] was published on February 8, 2011 and provides the following insights to the near-term energy environment. World energy demand is expected to continue to increase in 2011 and 2012, particularly in countries outside of the Organization for Economic Cooperation and Development ("OECD"). Among the OECD regions the only growth in energy consumption over the next two years is expected to be North America and that is expected to be offset by declines in OECD regions in Europe and Asia. OPEC's spare capacity is expected to remain above 4 mmbbls/day over the next two years while OPEC crude oil production is expected to increase by 5% by 2012 as global demand scales up.

Additionally, recent developments in Egypt, Libya and other North African and Middle East countries add uncertainty to oil and natural gas supply and demand. The Company closely monitors the developments in these areas.

Notes:

(1) "Canadian Energy Overview 2009", June 2010, National Energy Board.

(2) "Crude Oil Forecast, Markets and Pipelines", June 2010, Canadian Association of Petroleum Producers.

(3) "Energy Outlook" Winter 2010, National Energy Board.

(4) "Annual Energy Outlook 2011 Early Release Overview", December 2010, Energy Information Administration U.S. Department of Energy.

(5) "Short-Term Energy Outlook," February 8, 2011, Energy Information Administration U.S. Department of Energy.

DESCRIPTION OF HUSKY'S BUSINESS

General

Husky is a publicly held integrated international energy and energy related company headquartered in Calgary, Alberta, Canada.

Husky's business is conducted predominantly in three major business segments - Upstream, Midstream and Downstream.

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's Upstream operations and key prospects are located in Western Canada, the Atlantic Region, offshore China, and offshore Indonesia (Upstream business segment).

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

Downstream includes refining of light and heavy crude oil, production of ethanol, and marketing of refined petroleum products including gasoline, diesel, jet fuel, blending stocks, ethanol blended fuels, asphalt and the marketing of a wide variety of merchandise through convenience stores at Husky's retail outlet locations. The Downstream segment includes the Canadian refined products business segment and the U.S. refining and marketing business segment.

Social and Environmental Policy

Husky approaches social responsibility and sustainable development by seeking a balance among economic, operational reliability, health, safety, environmental and social issues while maintaining growth. Husky strives to find solutions to these issues that do not compromise the needs of future generations. In 2008, Husky implemented the Husky Operational Integrity Management System ("HOIMS") which is followed by all Husky businesses, with particular emphasis on projects and operations, and manages operational integrity throughout the life cycle of the assets. HOIMS includes 14 fundamental elements; each element contains well defined aims and expectations that guide Husky to continuously improve operational integrity performance outlining the overall intent behind each element and the individual activities that are undertaken to support the aims. HOIMS guides Husky employees in effectively managing the risks associated with Husky's business and creating a safe and secure place to work. Resources are applied and dedicated to the continued implementation and execution of HOIMS, and progress is monitored at all levels of the Company. Periodic reviews and audits are conducted to ensure that HOIMS is effectively integrated into daily operations and to continuously improve performance.

Aims:

1. Ensure all levels of management demonstrate leadership and commitment to operational integrity. Define and ensure appropriate accountability for HOIMS throughout the organization.
2. Prevent incidents by identifying and minimizing workplace and personal health risks. Promote and reinforce all safe behaviours.
3. Manage risks by performing comprehensive risk assessments to provide essential decision-making information. Develop and implement plans to manage significant risks and impacts to as low as reasonably practical levels.
4. Be prepared for an emergency or security threat. Identify all necessary actions to be taken to protect people, the environment, the organization's assets and reputation in the event of an emergency or security threat.
5. Maintain operations reliability and integrity by use of clearly defined and documented operational, maintenance, inspection and corrosion programs. Seek improvements in process and equipment dependability by systematically eliminating defects and sources of loss.
6. Provide assurance that personnel possess the necessary competencies, knowledge, abilities and demonstrate behaviours to perform their tasks and designated responsibilities effectively, efficiently and safely.
7. Report and investigate all incidents. Learn from incidents and use the information to take corrective action and prevent recurrence.

8. Operate responsibly to minimize the environmental impact of how we conduct our business. Leave a positive legacy behind us when operations cease.
9. Ensure that risks and exposures from proposed changes are identified, evaluated and managed to remain at an acceptable level.
10. Identify, maintain and safeguard important information. Ensure personnel can readily access and retrieve information. Promote and encourage constructive dialogue within the organization to share industry recommended practices and acquired knowledge.
11. Ensure conformance with Corporate policies and compliance with all relevant government regulations. Work constructively to influence proposed laws and regulations, and debate on emerging issues.
12. Design, construct, commission, operate and decommission all assets in a healthy, safe, secure, environmentally sound, reliable and efficient manner.
13. Ensure contractors and suppliers perform in a manner that is consistent and compatible with Husky's policies and business performance standards. Ensure contracted services and procured materials meet the requirements and expectations of Husky's standards.
14. Confirm that HOIMS processes are implemented and assess whether they are working effectively. Measure progress and continually improve towards meeting HOIMS objectives, targets, and key performance indicators.

Health, Safety and Environment

The Health, Safety and Environment Committee of the Board of Directors is responsible for reviewing and recommending for approval by the Board of Directors updates to the health, safety and environment policy, the development with management and achievement of specific environmental objectives and targets, and for monitoring compliance with the Company's environmental policies and regulatory requirements. The mandate of the Health, Safety and Environment Committee is available on the Husky website at www.huskyenergy.com.

Environmental Protection

Husky's operations are subject to various environmental requirements under federal, provincial, state and local laws and regulations, as well as international conventions. These laws and regulations cover matters such as air emissions, wastewater discharge, freshwater use, land disturbances and handling and disposal of waste materials. These laws and regulations have proliferated and become more complex over time, governing an increasingly broad aspect of the industry's mode of operating and product characteristics. Husky continues to monitor emerging environmental laws and regulations and proactively implements programs as required for compliance. According to the American Petroleum Institute, the oil and gas industry has invested over U.S. $209 billion since 1990 toward improving the environmental performance of its products, facilities and operations. In 2009, the refining sector accounted for 63% and the upstream sector accounted for 24% of total oil and gas industry environmental expenditures in the United States. In 2009, just over half of the industry's environment expenditures were directed toward reducing emissions into the atmosphere. [(1)]

Husky is required by the Government of Canada to report facilities that emit greater than 50,000 tonnes of CO_2E. The Lloydminster Upgrader, Lloydminster Refinery, Prince George Refinery, *SeaRose FPSO*, Ram River gas plant, Rainbow Lake gas plant, Tucker thermal oil plant, Bolney SAGD thermal plant, Pikes Peak CSS thermal plant and Lloydminster and Minnedosa ethanol plants are in this category. Husky has implemented an Environmental Performance Reporting System ("EPRS") that will gather, consolidate, calculate, report and identify trends including greenhouse gas emissions. To ensure the integrity of the EPRS data, Husky will have an independent third party audit performed at the Ram River gas plant and Tucker thermal oil plant.

Husky is also a member of the Integrated CO_2 Network, which is working to reduce greenhouse gas emissions. The group continues to study technologies in respect of capture, transportation and storage of CO_2. A project is underway at Husky to capture, compress and liquefy CO_2 from the Lloydminster ethanol plant for injection into heavy oil fields for Enhanced Oil Recovery. At Lloydminster and Rainbow Lake, Husky utilizes cogeneration to produce both electricity and thermal energy for use at its processing facilities. This configuration has less adverse effects on the environment and is cost effective. Electrical energy in excess of Husky's requirements is sold into the grid. At Husky's Tucker SAGD project vapour recovery systems are in use on all tanks and process vessels.

Husky has undertaken programs to minimize water consumption, particularly freshwater, and minimize risk to water resources. At the Tucker project, 90% of water is recycled and very saline (i.e. non-potable) water is used for make-up water. Husky is implementing various technologies to reduce water usage. Husky's alkaline

surfactant polymer floods ("ASP") which increases the efficiency of water and the use of CO_2 to mobilize heavy oil in the reservoir are being evaluated in pilots to reduce overall water consumption.

A large proportion of environmental costs are embedded in general capital costs, particularly when compliance is achieved by upgrading or expanding facilities. Husky continually implements a variety of initiatives that have cost efficiency, environmental protection and safety benefits. Such projects have included gas conservation, vapour recovery, boiler/heater efficiency and tank and pipeline integrity. At December 31, 2010, Husky had 555 retail locations in its light refined products operations, which consisted of 403 owned or leased locations (Husky controlled) and 152 independent retailer locations. Husky is continually monitoring the owned and leased locations for environmental compliance and, where required, performing remediation which has averaged approximately $6 million per year for the past five years including routine underground tank replacements. During 2010, five locations received new tanks at a cost of approximately $4 million. In addition, 13 sites received line and dispenser replacements at a cost of approximately $5 million. In 2010, Husky commenced a steel tank retirement program at decommissioned locations. During 2010, ten locations had such tanks removed. Husky expects to remove the steel tanks at a similar number of locations in 2011. Husky intends to spend approximately $14 million in 2011 on environmental upgrades, remediation, tank replacements and steel tank retirements.

Husky has several "legacy" (inactive facility) sites which require remediation. These inactive sites range from refinery sites to retail locations. In 2010, Husky spent $3 million on remediation and expects to spend approximately $23 million over the next five years to complete remediation of these locations. Ongoing remediation and reclamation work is occurring at over 2,500 abandoned well sites and 100 abandoned facility sites. Husky plans to spend between $12 and $15 million annually on these programs. Husky spent approximately U.S. $49 million in 2010 at the Lima Refinery in respect of vapour recovery, emission control and water treatment and an additional U.S. $7 million for the operation of its waste water treatment facility.

It is not possible to predict with certainty the amount of additional investment in new or existing facilities required to be incurred in the future for environmental protection or to address regulatory compliance requirements, such as reporting. Although these costs may be significant, Husky does not expect that they will have a material adverse effect on liquidity and financial position over the long-term.

Note:

(1) "Environmental Expenditures by the U.S. Oil and Natural Gas Industry," 2011, American Petroleum Institute.

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 Husky's 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, reduce the value and quantities of Husky's heavier crude oil reserves and 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 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.

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 and pricing 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 pipeline and processing capacity.

Reserves data and future net revenue estimates

The reserves data in this Annual Information Form represent estimates only. In general, estimates of economically recoverable crude oil and gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, including with respect to royalty payments, all of which may vary considerably from actual results. All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Additions to reserves are required to maintain asset value and production

In order to maintain the Company's future production of crude oil, natural gas and natural gas liquids and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as the reserves are depleted while the associated unit operating costs increase. In order to prevent this the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. Maintaining an inventory of developable projects depends on, among other things, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completing long-lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

Competition

The energy 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 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, to gain access to and retain adequate markets for its products and services and gain access to capital markets. Husky's ability to successfully complete development projects could be adversely affected by an inability to acquire economic supplies and services due to competition. Subsequent increases in the cost of, 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.

Delays and cost overruns of capital projects

Husky is involved in capital projects such as exploration programs, development of oil and gas properties, plant and facilities construction, expansion and modification. Project delays can adversely affect expected cash flow and overall project costs thereby eroding project economics. Risk factors include, but are not limited to:

- availability and cost of capital;
- availability of skilled labour;
- availability of manufacturing capacity, supplies, material and equipment;
- regulatory approvals;
- faulty construction and design errors;
- accidents, labour disruptions, bankruptcies and productivity issues affecting Husky directly or indirectly; and
- unexpected changes in the scope of a project.

Foreign exchange risk

Husky's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of expenditures are in Canadian dollars. The majority of 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. 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, 2010, 74% or $3.1 billion of Husky's long-term debt was denominated in U.S. dollars. The percentage of long-term debt exposed to the U.S./Cdn exchange rate decreases to 67% when cross currency swaps are included. Additionally, U.S. $987 million of the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment, further reducing the long-term debt exposed to the U.S./Cdn exchange rate to 42%.

The contribution receivable representing BP's obligation to fund capital expenditures of the Sunrise partnership is denominated in U.S. dollars and gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange gains and losses in the current year. At December 31, 2010, Husky's share of the balance of this receivable was U.S. $1.3 billion including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in Other Comprehensive Income as this item relates to a self sustaining foreign operation. At December 31, 2010, Husky's share of the balance of this obligation was U.S. $1.4 billion including accrued interest.

Operational risks and hazards

Husky's businesses are subject to inherent operational risks and hazards in respect of safety and the environment that requires continuous vigilance. The Company seeks to minimize these operational risks and hazards by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these operational risks and hazards effectively could result in unexpected incidents, including releases of restricted substances, explosions, marine catastrophe or mechanical failures resulting in personal injuries, loss of life, environmental damage, property damage, loss of revenues, legal liability and/or disruption to operations. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks and hazards. Nonetheless, insurance proceeds may not be sufficient to cover all losses. As a result of future changes in market conditions insurance coverage might not remain available for all types of operational risks and hazards at reasonable rates.

Environmental regulation

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of federal, provincial, state and local 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 be significant, however, Husky does not expect that they will have a material adverse effect on our financial condition and results of operations.

Husky anticipates that changes in environmental legislation may require 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 our financial condition and results of operations.

In 1994, the United Nations' Framework Convention on Climate Change ("UNFCCC") came into force and the Congress of the Parties ("COP") meet annually to assess progress. The Kyoto Protocol, COP 3, was adopted in 1997. The Kyoto Protocol, among other things, set binding targets for the reduction of greenhouse gas emissions by industrialized nations. The first target required reduction of greenhouse gas emissions to 1990 levels by 2000. The second target required reducing greenhouse gas emissions by 6-8% of 1990 levels during the period 2008 – 2012. Canada ratified the Kyoto Protocol in December 2002. At COP 13 in 2007, the Bali Action Plan was adopted. The Bali Action Plan provided structure and timeline for post 2012 implementation. In December 2009, COP 15 was convened in Copenhagen with the goal of establishing an agreement on global climate change for 2012 and beyond. Instead, a group of countries including the United States, China, the European Union, India and Japan issued an accord outside of the UNFCCC process. The Copenhagen Accord is non-binding memorandum of understanding that sets a goal of limiting global warming to below 2 degrees Celsius above pre-industrial times and allows each nation to set its own target for 2020. Canada has committed to cut greenhouse gas emissions by 17% below 2005 levels by 2020; this aligns Canada with the stated target of the United States. The commitments will be reviewed by 2015 to assess progress toward the long-term goal to limit the global average temperature rise to 1.5 degrees Celsius. The effect of the Copenhagen Accord on Husky is currently uncertain but will continue to evolve. In December 2010, the Cancun Agreements were adopted at COP 16. This agreement provides a framework to advance the Copenhagen Accord. COP 17 will be held in November/December 2011 in Durban South Africa.

The Federal Government of Canada has announced certain regulations in respect of greenhouse gases and other pollutants. Although the impact of these regulations is uncertain, they may adversely affect the Company's operations and increase costs. These regulations may become more onerous over time as public and political pressures increase to implement initiatives that further reduce the emission of greenhouse gases.

The Deepwater Horizon oil spill in the Gulf of Mexico has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil operations. Stricter regulation of offshore oil and gas operations has already been implemented in the Gulf of Mexico. Further regulation, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in the Gulf of Mexico. In the event that similar changes in environmental regulation occur with respect to Husky's operations in the Atlantic Region or in the South China Sea, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

The United States Environmental Protection Agency ("EPA") has promulgated the so-called 'Tailoring Rule', which, beginning January 2, 2011, phases in over time restrictions on greenhouse gas emissions from stationary sources, including power plants and petroleum refineries, beginning with the largest emitters, where such sources are required to obtain a new or modified permit based on non-greenhouse gas emissions. The EPA has also promulgated regulations requiring data collection, beginning January 1, 2010, and reporting, beginning March 31, 2011, of greenhouse gas emissions from stationary sources in the oil and gas industry emitting more than 25,000 tons per year of greenhouse gases in carbon dioxide equivalent. This reporting requirement applies to Husky's U.S. operations. However, these regulations are subject to challenge in Congress and the courts. Congress is expected to consider in the coming session proposals to block or delay the EPA's regulation of greenhouse gas emissions. Among several legal challenges, the State of Texas, the National Association of Manufacturers and other organizations are seeking a stay of the Tailoring Rule and the EPA's other regulations relating to greenhouse gas emissions. It is not possible to predict the ultimate outcome of these challenges. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky and the pending and anticipated challenges could result in the staying of the regulations. Husky's operations may be impacted by future United States greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require Husky's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

Changes to government fiscal policy

All of Husky's oil and gas production is subject to royalties which are potentially impacted by changes in government fiscal policies. The Company maintains close contact with governments in the areas within which it operates.

General economic conditions

General economic conditions may have a material adverse effect on the Company's results of operations, liquidity and financial condition. The 2008/2009 economic and financial crisis contributed to heightened

uncertainty and a deterioration of near-term expectations in respect of the global economy. Although economic recovery is underway, there is no assurance that the crisis will not recur in the future. A decline in economic activity will reduce demand for petroleum products and adversely affect the price the Company receives for its commodities. The Company's cash flow could decline, assets could be impaired, future access to capital could be restricted and major development projects could be delayed.

Cost or availability of oil and gas field equipment

The cost or availability of oil and gas field equipment adversely affects the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including land and offshore drilling rigs, land and offshore geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at a reasonable price.

International operations

International operations can have uncertain political, economic and other risks. The Company's operations that are in certain jurisdictions may be adversely affected by political, economic or social instability or events. These events may include, but are not limited to, acts of war, terrorism, abduction, expropriation, onerous fiscal policy, renegotiation or nullification of agreements, imposition of onerous regulation, financial constraints and unreasonable taxation. This could adversely affect the Company's interest in its foreign operations and future profitability.

Climatic conditions

Climatic conditions may have significant adverse effects on operations. Demand for energy can be affected to a large degree by weather and climate. In addition, the Company's exploration, production and construction operations can be affected by extreme weather, which may result in cessation of production, delay of exploration and development activities or delay of plant construction. All of these could potentially cause financial losses.

Recruitment, retention and succession

Failure to retain current employees and attract new skilled employees could materially affect the Company's ability to conduct its business. Demand for qualified employees with appropriate experience remains high. In addition, a significant portion of the workforce will become eligible for retirement in the near term.

Credit rating risk

The Company's debt instruments are rated by various credit rating agencies. These ratings affect the Company's ability to gain access to reasonably priced debt financing. If any of the Company's credit rating agencies downgrade the Company's debt instruments it may restrict the Company's ability to issue debt and may also increase the cost of borrowing, including existing credit facilities.

Upstream Operations

Disclosures of Oil and Gas Activities

In the tables that follow, the following definitions apply: light crude oil (30° API and lighter), medium crude oil (between 20° and 30° API), heavy crude oil (between 20° API and 10° API and is liquid) and bitumen (solid or semi-solid with a viscosity greater than 10,000 centipoise).

Production

	2010					
	Total	Western Canada	Atlantic Region	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	80.4	23.0	46.7	69.7	10.7	—
Medium crude oil	25.4	25.4	—	25.4	—	—
Heavy crude oil	74.5	74.5	—	74.5	—	—
Bitumen	22.3	22.3	—	22.3	—	—
Total gross (1)	202.6	145.2	46.7	191.9	10.7	—
Total net (1)	181.1	137.0	35.8	172.8	8.3	—
Natural Gas *(mmcf/day)*						
Gross (1)	506.8	506.8	—	506.8	—	—
Net (1)	478.7	478.7	—	478.7	—	—

	2009					
	Total	Western Canada	Atlantic Region	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	89.1	22.8	55.1	77.9	11.1	0.1
Medium crude oil	25.4	25.4	—	25.4	—	—
Heavy crude oil	78.6	78.6	—	78.6	—	—
Bitumen	23.1	23.1	—	23.1	—	—
Total gross (1)	216.2	149.9	55.1	205.0	11.1	0.1
Total net (1)	181.7	130.5	41.8	172.3	9.3	0.1
Natural Gas *(mmcf/day)*						
Gross (1)	541.7	541.7	—	541.7	—	—
Net (1)	457.3	457.3	—	457.3	—	—

	2008					
	Total	Western Canada	Atlantic Region	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	122.9	24.6	86.1	110.7	12.1	0.1
Medium crude oil	26.9	26.9	—	26.9	—	—
Heavy crude oil	84.4	84.4	—	84.4	—	—
Bitumen	22.6	22.6	—	22.6	—	—
Total gross (1)	256.8	158.5	86.1	244.6	12.1	0.1
Total net (1)	206.8	134.9	62.7	197.6	9.1	0.1
Natural Gas *(mmcf/day)*						
Gross (1)	594.4	594.4	—	594.4	—	—
Net (1)	464.2	464.2	—	464.2	—	—

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

	2010					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
	($ millions)					
Crude Oil						
Light crude oil and NGL	2,262	561	1,376	1,937	321	4
Medium crude oil	601	601	—	601	—	—
Heavy crude oil	1,601	1,601	—	1,601	—	—
Bitumen	470	470	—	470	—	—
Total gross	4,934	3,233	1,376	4,609	321	4
Total net	3,945	2,621	1,073	3,694	247	4
Natural Gas						
Gross	725	725	—	725	—	—
Net	685	685	—	685	—	—
Processing/Transportation	85	41	44	85	—	—

	2009					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
	($ millions)					
Crude Oil						
Light crude oil and NGL	2,042	455	1,300	1,755	283	4
Medium crude oil	522	522	—	522	—	—
Heavy crude oil	1,507	1,507	—	1,507	—	—
Bitumen	437	437	—	437	—	—
Total gross	4,508	2,921	1,300	4,221	283	4
Total net	3,650	2,403	1,010	3,413	233	4
Natural Gas						
Gross	759	759	—	759	—	—
Net	727	727	—	727	—	—
Processing/Transportation	46	46	—	46	—	—

	2008					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
	($ millions)					
Crude Oil						
Light crude oil and NGL	4,374	780	3,157	3,937	433	4
Medium crude oil	805	805	—	805	—	—
Heavy crude oil	2,223	2,223	—	2,223	—	—
Bitumen	582	582	—	582	—	—
Total gross	7,984	4,390	3,157	7,547	433	4
Total net	6,225	3,621	2,289	5,910	312	3
Natural Gas						
Gross	1,876	1,876	—	1,876	—	—
Net	1,563	1,563	—	1,563	—	—
Processing/Transportation	72	72	—	72	—	—

Sales Prices

	2010					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
Crude Oil *($/bbl)*						
Light crude oil and NGL	76.90	66.46	80.63	75.94	83.17	79.14
Medium crude oil	64.92	64.92	—	64.92	—	—
Heavy crude oil	58.91	58.91	—	58.91	—	—
Bitumen	57.84	57.84	—	57.84	—	—
Total crude oil and NGL	66.70	61.00	80.63	65.78	83.17	79.14
Natural Gas *($/mcf)*	3.86	3.86	—	3.86	—	—

	2009					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
Crude Oil *($/bbl)*						
Light crude oil and NGL	62.70	54.62	64.60	61.68	69.62	80.28
Medium crude oil	56.37	56.37	—	56.37	—	—
Heavy crude oil	52.54	52.54	—	52.54	—	—
Bitumen	51.90	51.90	—	51.90	—	—
Total crude oil and NGL	57.11	53.40	64.60	56.42	69.62	80.28
Natural Gas *($/mcf)*	3.83	3.83	—	3.83	—	—

	2008					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
Crude Oil *($/bbl)*						
Light crude oil and NGL	97.28	86.65	100.12	97.13	98.56	118.97
Medium crude oil	81.79	81.79	—	81.79	—	—
Heavy crude oil	71.98	71.98	—	71.98	—	—
Bitumen	70.24	70.24	—	70.24	—	—
Total crude oil and NGL	84.96	75.67	100.12	84.28	98.56	118.97
Natural Gas *($/mcf)*	7.94	7.94	—	7.94	—	—

Capital Expenditures

	2010							
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**United States**	**China**	**Indonesia**	**Libya**
	($ millions)							
Property acquisition	389	389	—	389	—	—	—	—
Exploration	687	210	96	306	—	369	12	—
Development	2,095	1,636	396	2,032	—	60	—	3
	3,171	2,235	492	2,727	—	429	12	3

	2009							
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**United States**	**China**	**Indonesia**	**Libya**
	($ millions)							
Property acquisition	309	307	—	307	2	—	—	—
Exploration	841	228	95	323	23	458	37	—
Development	1,176	654	510	1,164	—	7	—	5
	2,326	1,189	605	1,794	25	465	37	5

	2008							
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**United States**	**China**	**Indonesia**	**Libya**
	($ millions)							
Property acquisition	530	485	—	485	45	—	—	—
Exploration	836	436	160	596	15	214	11	—
Development	2,214	1,640	569	2,209	—	3	—	2
	3,580	2,561	729	3,290	60	217	11	2

Oil and Gas Netbacks [(1)]

	2010					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	75.39	59.66	80.63	74.16	83.14	79.14
Royalties	16.77	10.11	19.25	16.43	19.21	—
Operating costs	11.00	15.03	10.33	11.78	5.74	29.01
Netback	47.62	34.52	51.05	45.95	58.19	50.13
Medium crude oil						
Sales revenue	62.97	62.97	—	62.97	—	—
Royalties	11.11	11.11	—	11.11	—	—
Operating costs	16.24	16.24	—	16.24	—	—
Netback	35.62	35.62	—	35.62	—	—
Heavy crude oil						
Sales revenue	58.09	58.09	—	58.09	—	—
Royalties	8.50	8.50	—	8.50	—	—
Operating costs	15.51	15.51	—	15.51	—	—
Netback	34.08	34.08	—	34.08	—	—
Bitumen						
Sales revenue	57.84	57.84	—	57.84	—	—
Royalties	8.53	8.53	—	8.53	—	—
Operating costs	20.37	20.37	—	20.37	—	—
Netback	28.94	28.94	—	28.94	—	—
Total crude oil						
Sales revenue	65.36	59.16	80.63	64.37	83.14	79.14
Royalties	12.03	9.21	19.25	11.64	19.21	—
Operating costs	14.40	16.32	10.33	14.86	5.74	29.01
Netback	38.93	33.63	51.05	37.87	58.19	50.13
Natural Gas *($/mcf)*						
Sales revenue	4.33	4.33	—	4.33	—	—
Royalties	0.45	0.45	—	0.45	—	—
Operating costs	1.85	1.85	—	1.85	—	—
Netback	2.03	2.03	—	2.03	—	—
Equivalent Unit *($boe)*						
Sales revenue	53.77	47.07	80.63	52.75	83.14	79.14
Royalties	9.31	6.84	19.25	8.94	19.21	—
Operating costs	13.33	14.44	10.33	13.74	5.74	29.01
Netback	31.13	25.79	51.05	30.07	58.19	50.13

Note:

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

Oil and Gas Netbacks [1] ***(continued)***

	2009					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	62.38	52.28	64.60	61.28	69.62	80.28
Royalties	13.36	6.03	16.34	13.56	12.16	—
Operating costs	9.96	15.79	8.73	10.63	5.35	16.35
Netback	39.06	30.46	39.53	37.09	52.11	63.93
Medium crude oil						
Sales revenue	54.88	54.88	—	54.88	—	—
Royalties	8.67	8.67	—	8.67	—	—
Operating costs	15.40	15.40	—	15.40	—	—
Netback	30.81	30.81	—	30.81	—	—
Heavy crude oil						
Sales revenue	51.95	51.95	—	51.95	—	—
Royalties	7.24	7.24	—	7.24	—	—
Operating costs	13.26	13.26	—	13.26	—	—
Netback	31.45	31.45	—	31.45	—	—
Bitumen						
Sales revenue	51.90	51.90	—	51.90	—	—
Royalties	7.13	7.13	—	7.13	—	—
Operating costs	16.38	16.38	—	16.38	—	—
Netback	28.39	28.39	—	28.39	—	—
Total crude oil						
Sales revenue	56.49	52.50	64.60	55.76	69.62	80.28
Royalties	9.86	7.31	16.34	9.74	12.16	—
Operating costs	12.53	14.46	8.73	12.92	5.35	16.35
Netback	34.10	30.73	39.53	33.10	52.11	63.93
Natural Gas *($/mcf)*						
Sales revenue	4.08	4.08	—	4.08	—	—
Royalties	0.42	0.42	—	0.42	—	—
Operating costs	1.69	1.69	—	1.69	—	—
Netback	1.97	1.97	—	1.97	—	—
Equivalent Unit *($boe)*						
Sales revenue	47.06	41.98	64.60	46.21	69.62	80.28
Royalties	7.70	5.51	16.34	7.53	12.16	—
Operating costs	11.82	12.86	8.73	12.09	5.35	16.35
Netback	27.54	23.61	39.53	26.59	52.11	63.93

Note:

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

Oil and Gas Netbacks [1] ***(continued)***

	2008					
	Total	**Western Canada**	**Atlantic Region**	**Canada**	**China**	**Libya**
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	96.73	82.97	100.12	96.51	98.56	118.97
Royalties	25.14	11.53	28.45	24.89	27.65	—
Operating costs	6.56	13.90	4.99	6.74	4.78	17.35
Netback	65.03	57.54	66.68	64.88	66.13	101.62
Medium crude oil						
Sales revenue	79.91	79.91	—	79.91	—	—
Royalties	13.91	13.91	—	13.91	—	—
Operating costs	15.60	15.60	—	15.60	—	—
Netback	50.40	50.40	—	50.40	—	—
Heavy crude oil						
Sales revenue	71.45	71.45	—	71.45	—	—
Royalties	10.55	10.55	—	10.55	—	—
Operating costs	13.68	13.68	—	13.68	—	—
Netback	47.22	47.22	—	47.22	—	—
Bitumen						
Sales revenue	70.24	70.24	—	70.24	—	—
Royalties	10.42	10.42	—	10.42	—	—
Operating costs	22.93	22.93	—	22.93	—	—
Netback	36.89	36.89	—	36.89	—	—
Total crude oil						
Sales revenue	84.13	74.43	100.12	83.47	98.56	118.97
Royalties	17.75	11.26	28.45	17.28	27.65	—
Operating costs	11.39	15.27	4.99	11.68	4.78	17.35
Netback	54.99	47.90	66.68	54.51	66.13	101.62
Natural Gas *($/mcf)*						
Sales revenue	8.21	8.21	—	8.21	—	—
Royalties	1.60	1.60	—	1.60	—	—
Operating costs	1.59	1.59	—	1.59	—	—
Netback	5.02	5.02	—	5.02	—	—
Equivalent Unit *($boe)*						
Sales revenue	74.57	64.89	100.12	73.72	98.56	118.97
Royalties	15.52	10.63	28.45	15.09	27.65	—
Operating costs	10.93	13.16	4.99	11.14	4.78	17.35
Netback	48.12	41.10	66.68	47.49	66.13	101.62

Note:

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

Producing and Non-Producing Wells

Productive Wells

	Oil Wells		Natural Gas Wells		Total	
	Gross [1] [2]	Net [1]	Gross [1] [2]	Net [1]	Gross [1] [2]	Net [1]
Canada						
Alberta	4,484	3,580	5,770	4,407	10,254	7,987
Saskatchewan	6,582	5,488	1,446	1,311	8,028	6,799
British Columbia	204	59	283	242	487	301
Newfoundland	25	9	—	—	25	9
	11,295	9,136	7,499	5,960	18,794	15,096
International						
China	32	13	—	—	32	13
Libya	3	1	—	—	3	1
	35	14	—	—	35	14
As at December 31, 2010	11,330	9,150	7,499	5,960	18,829	15,110
Canada						
Alberta	4,281	3,395	5,834	4,480	10,115	7,875
Saskatchewan	5,818	4,789	1,395	1,261	7,213	6,050
British Columbia	203	58	253	214	456	272
Newfoundland	23	8	—	—	23	8
	10,325	8,250	7,482	5,955	17,807	14,205
International						
China	31	12	—	—	31	12
Libya	2	1	—	—	2	1
	33	13	—	—	33	13
As at December 31, 2009	10,358	8,263	7,482	5,955	17,840	14,218
Canada						
Alberta	4,276	3,406	5,631	4,346	9,907	7,752
Saskatchewan	5,697	4,682	1,318	1,205	7,015	5,887
British Columbia	203	58	259	205	462	263
Newfoundland	23	8	—	—	23	8
	10,199	8,154	7,208	5,756	17,407	13,910
International						
China	29	12	—	—	29	12
Libya	2	1	—	—	2	1
	31	13	—	—	31	13
As at December 31, 2008	10,230	8,167	7,208	5,756	17,438	13,923

Non-Producing Wells

	2010					
	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada	3,836	3,351	1,425	1,198	5,261	4,549

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. Productive wells are those producing or capable of producing at December 31, 2010.

(2) The above table does not include producing wells in which Husky has no working interest but does have a royalty interest. At December 31, 2010, Husky had a royalty interest in 3,937 wells of which 1,272 were oil producers and 2,665 were gas producers.

(3) For purposes of the above table, multiple completions are counted as a single well. Where one of the completions in a given well is an oil completion, the well is classified as an oil well. In 2010, there were 418 gross, 399 net oil wells and 843 gross, 704 net natural gas wells which were completed in two or more formations and from which production is not commingled.

Landholdings

	Developed Acreage	
	Gross	**Net**
	(thousands of acres)	
As at December 31, 2010		
Western Canada		
Alberta	4,172	2,729
Saskatchewan	891	704
British Columbia	172	133
Manitoba	2	—
	5,237	3,566
Eastern Canada	54	18
	5,291	3,584
China	17	7
Libya	7	2
	5,315	3,593
As at December 31, 2009		
Western Canada		
Alberta	4,100	2,692
Saskatchewan	856	672
British Columbia	168	128
	5,124	3,492
Eastern Canada	54	18
	5,178	3,510
China	17	7
Libya	7	2
	5,202	3,519
As at December 31, 2008		
Western Canada		
Alberta	3,159	2,658
Saskatchewan	779	657
British Columbia	167	114
	4,105	3,429
Eastern Canada	54	18
	4,159	3,447
China	17	7
Libya	7	2
	4,183	3,456

Landholdings (continued)

	Undeveloped Acreage	
	Gross	**Net**
	(thousands of acres)	
As at December 31, 2010		
Western Canada		
Alberta	4,801	3,407
Saskatchewan	1,712	1,522
British Columbia	1,020	747
Manitoba	4	1
	7,537	5,677
Northwest Territories and Arctic	943	303
Eastern Canada	4,777	2,989
	13,257	8,969
United States	1,100	484
China	990	990
Indonesia	1,940	1,595
Greenland	8,471	5,983
	25,758	18,021
As at December 31, 2009		
Western Canada		
Alberta	4,941	3,523
Saskatchewan	1,571	1,384
British Columbia	996	739
Manitoba	4	1
	7,512	5,647
Northwest Territories and Arctic	1,207	487
Eastern Canada	5,128	3,137
	13,847	9,271
United States	1,707	422
China	1,970	1,970
Indonesia	1,940	1,595
Greenland	8,471	5,983
	27,935	19,241
As at December 31, 2008		
Western Canada		
Alberta	4,287	3,743
Saskatchewan	1,563	1,473
British Columbia	962	662
Manitoba	1	1
	6,813	5,879
Northwest Territories and Arctic	1,042	629
Eastern Canada	4,364	3,192
	12,219	9,700
United States	1,707	422
China	6,337	6,337
Indonesia	2,992	2,646
Greenland	8,471	5,983
	31,726	25,088

The Company does not have any material work commitments associated with undeveloped land. See "Description of Major Properties and Facilities". Over the next 12 months, approximately 687,000 acres or less than 8% of the Company's net undeveloped landholdings in Canada will be subject to expiry.

Drilling Activity

	Year ended December 31					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Western Canada Drilling						
Exploration						
Oil	60	51	18	9	80	70
Gas	37	31	37	22	102	79
Dry	8	8	7	6	27	23
	105	90	62	37	209	172
Development						
Oil	815	722	315	278	685	578
Gas	73	53	122	61	435	270
Dry	10	9	7	7	36	36
	898	784	444	346	1,156	884
	1,003	874	506	383	1,365	1,056
Atlantic Region						
Development						
Oil	2	1.4	—	—	1	0.7
International						
Exploration						
Dry	—	—	1	0.5	—	—
Development						
Oil	1	0.4	2	0.8	—	—
Gas	2	1.0	—	—	—	—
	3	1.4	2	0.8	—	—

Service/Stratigraphic Test Wells	2010	
	Gross	Net
Canada	75	63
China	9	9

Present Activities

	Exploratory		Development	
Wells Drilling (1)	Gross	Net	Gross	Net
Western Canada	8	7.5	33	27.6
East Coast – Canada	—	—	1	0.7
International	—	—	2	1.4

Service/Stratigraphic Test Wells(1)	2010	
	Gross	Net
Canada	19	15.0

Note:

(1) Denotes wells that were being drilled at February 24, 2011.

Oil and Gas Reserves Disclosures

Husky's oil and gas reserves are estimated in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (COGEH) and the reserve data disclosed conforms with the requirements of NI 51-101. Husky's oil and gas reserves are prepared by internal reserves evaluation staff using a formalized process for determining, approving and booking reserves. This process requires all reserves evaluations to be done on a consistent basis using established definitions and guidelines. Approval of individually significant reserve changes requires review by an internal panel of qualified reserves evaluators.

In prior years Husky applied for and was granted an exemption from certain of the provisions of NI 51-101, which permitted the Company to present oil and gas reserves disclosures in accordance with the rules of the United States SEC guidelines and the United States Financial Accounting Standards Board (the "U.S. Rules"). This exemption is no longer available for the Company's reserves reporting in Canada, although the Company has received an exemption from the Canadian Securities Administrators which allows the Company to also disclose its reserves under the U.S. Rules as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101. The Company has disclosed reserves information in accordance with the U.S. Rules in Exhibit 99.1 in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com .

The material differences between reserve quantities disclosed under NI 51-101 and those disclosed under the U.S. Rules is that NI 51-101 requires the determination of reserve quantities to be based on forecast pricing assumptions whereas the U.S. Rules require the determination of reserve quantities to be based on constant price assumptions calculated using a 12 month average price for the year (sum of the benchmark price on the first calendar day of each month in the year divided by 12).

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 NGL reserve estimates. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values based on forecast assumptions are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the COGEH.

Note that the numbers in each column of the tables throughout this section may not add due to rounding.

Summary of Oil and Natural Gas Reserves
As at December 31, 2010
Forecast Prices and Costs

Canada

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	129.1	110.2	75.0	66.4	69.5	61.3	51.5	47.5
Developed Non-producing	2.0	1.8	3.6	3.2	12.3	11.8	—	—
Undeveloped	34.3	30.7	9.2	7.9	28.4	25.5	195.4	171.2
Total Proved	165.3	142.8	87.7	77.5	110.2	98.6	246.8	218.7
Probable:	102.4	83.2	20.2	17.7	32.4	29.0	1,039.8	777.6
Total Proved Plus Probable	267.8	226.0	107.9	95.2	142.7	127.6	1,286.6	996.3

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	30.1	27.2	1,487.3	1,266.6	41.3	32.5	619.3	533.6
Developed Non-producing	1.5	1.3	202.2	174.2	2.2	1.6	54.0	47.8
Undeveloped	10.2	9.7	454.7	418.1	12.4	9.6	357.1	316.2
Total Proved	41.8	38.1	2,144.2	1,858.9	55.9	43.7	1,030.4	897.5
Probable:	1.8	1.5	577.6	495.2	12.4	9.5	1,303.8	999.7
Total Proved Plus Probable	43.5	39.6	2,721.8	2,354.1	68.3	53.2	2,334.1	1,897.2

China

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	6.9	5.1	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	6.9	5.1	—	—	—	—	—	—
Probable:	3.2	2.4	—	—	—	—	—	—
Total Proved Plus Probable	10.2	7.5	—	—	—	—	—	—

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	—	—	—	—	0.2	0.1	7.1	5.2
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	—	—	—	—	0.2	0.1	7.1	5.2
Probable:	—	—	—	—	0.1	0.1	3.3	2.4
Total Proved Plus Probable	—	—	—	—	0.2	0.2	10.4	7.6

Summary of Oil and Natural Gas Reserves
As at December 31, 2010
Forecast Prices and Costs (continued)

Indonesia

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	—	—	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	—	—	—	—	—	—	—	—
Probable:	—	—	—	—	—	—	—	—
Total Proved Plus Probable	—	—	—	—	—	—	—	—

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	—	—	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	209.0	143.1	9.0	4.9	43.8	28.8
Total Proved	—	—	209.0	143.1	9.0	4.9	43.8	28.8
Probable:	—	—	49.3	29.1	2.1	0.8	10.3	5.7
Total Proved Plus Probable	—	—	258.3	172.1	11.1	5.7	54.1	34.4

Libya

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	0.2	0.2	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	0.2	0.2	—	—	—	—	—	—
Probable:	—	—	—	—	—	—	—	—
Total Proved Plus Probable	0.2	0.2	—	—	—	—	—	—

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	—	—	—	—	—	—	0.2	0.2
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	—	—	—	—	—	—	0.2	0.2
Probable:	—	—	—	—	—	—	—	—
Total Proved Plus Probable	—	—	—	—	—	—	0.2	0.2

Summary of Oil and Natural Gas Reserves
As at December 31, 2010
Forecast Prices and Costs (continued)

Total

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	136.2	115.5	75.0	66.4	69.5	61.3	51.5	47.5
Developed Non-producing	2.0	1.8	3.6	3.2	12.3	11.8	—	—
Undeveloped	34.3	30.7	9.2	7.9	28.4	25.5	195.4	171.2
Total Proved	172.5	148.1	87.7	77.5	110.2	98.6	246.8	218.7
Probable:	105.7	85.6	20.2	17.7	32.4	29.0	1,039.8	777.6
Total Proved Plus Probable	278.2	233.7	107.9	95.2	142.7	127.6	1,286.6	996.3

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	30.1	27.2	1,487.3	1,266.6	41.5	32.6	626.5	539.0
Developed Non-producing	1.5	1.3	202.2	174.2	2.2	1.6	54.0	47.8
Undeveloped	10.2	9.7	663.7	561.1	21.4	14.5	400.9	345.0
Total Proved	41.8	38.1	2,353.2	2,002.0	65.1	48.7	1,081.5	931.7
Probable:	1.8	1.5	626.9	524.2	14.5	10.4	1,317.4	1,007.8
Total Proved Plus Probable	43.5	39.6	2,980.1	2,526.2	79.6	59.1	2,398.8	1,939.5

Summary of Net Present Values of Future Net Revenue
As at December 31, 2010
Forecast Prices and Costs

Canada

	Before Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	13,061	10,738	9,233	8,163
Developed Non-producing	1,239	963	789	667
Undeveloped	4,884	2,973	1,841	1,120
Total Proved	19,184	14,675	11,863	9,950
Probable:	17,683	8,682	4,983	3,192
Total Proved Plus Probable	36,868	23,356	16,846	13,142

China

	Before Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	440	415	392	372
Developed Non-producing	—	—	—	—
Undeveloped	—	—	—	—
Total Proved	440	415	392	372
Probable:	192	164	142	124
Total Proved Plus Probable	632	579	534	495

Indonesia

	Before Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	—	—	—	—
Developed Non-producing	—	—	—	—
Undeveloped	277	171	103	58
Total Proved	277	171	103	58
Probable:	56	32	19	13
Total Proved Plus Probable	334	203	122	70

Summary of Net Present Values of Future Net Revenue
As at December 31, 2010
Forecast Prices and Costs (continued)

Libya

	Before Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	9	9	8	8
Developed Non-producing	—	—	—	—
Undeveloped	—	—	—	—
Total Proved	9	9	8	8
Probable:	3	3	2	2
Total Proved Plus Probable	12	11	10	10

Total

	Before Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	13,511	11,161	9,633	8,542
Developed Non-producing	1,239	963	789	667
Undeveloped	5,161	3,145	1,944	1,177
Total Proved	19,911	15,269	12,366	10,387
Probable:	17,935	8,880	5,147	3,331
Total Proved Plus Probable	37,846	24,150	17,513	13,717

Summary of Net Present Values of Future Net Revenue
As at December 31, 2010
Forecast Prices and Costs

Canada

	After Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	9,653	7,922	6,801	6,005
Developed Non-producing	917	710	578	487
Undeveloped	3,521	2,019	1,129	563
Total Proved	14,091	10,650	8,508	7,055
Probable:	12,975	6,217	3,460	2,138
Total Proved Plus Probable	27,066	16,868	11,968	9,193

China

	After Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	296	279	264	250
Developed Non-producing	—	—	—	—
Undeveloped	—	—	—	—
Total Proved	296	279	264	250
Probable:	129	110	95	83
Total Proved Plus Probable	424	389	358	332

Indonesia

	After Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	—	—	—	—
Developed Non-producing	—	—	—	—
Undeveloped	190	114	64	30
Total Proved	190	114	64	30
Probable:	34	19	12	8
Total Proved Plus Probable	224	133	76	38

Summary of Net Present Values of Future Net Revenue
As at December 31, 2010
Forecast Prices and Costs (continued)

Libya

	After Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	9	9	8	8
Developed Non-producing	—	—	—	—
Undeveloped	—	—	—	—
Total Proved	9	9	8	8
Probable:	3	3	2	2
Total Proved Plus Probable	12	11	10	10

Total

	After Income Taxes and Discounted at (%/year)			
($ millions)	**5%**	**10%**	**15%**	**20%**
Proved:				
Developed Producing	9,958	8,209	7,072	6,262
Developed Non-producing	917	710	578	487
Undeveloped	3,710	2,133	1,193	593
Total Proved	14,586	11,051	8,843	7,342
Probable:	13,141	6,349	3,569	2,231
Total Proved Plus Probable	27,726	17,401	12,413	9,573

Total Future Net Revenue for Total Proved Reserves - Undiscounted
As at December 31, 2010
Forecast Prices and Costs

($ millions)	Revenue	Royalties	Operating Costs	Develop-ment Cost	Abandon-ment and Reclama-tion Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada								
Proved:								
Developed Producing	40,040	6,773	12,422	1,251	2,335	17,260	4,480	12,780
Developed Non-producing	2,928	329	701	139	—	1,759	451	1,309
Undeveloped	24,123	3,433	6,570	5,599	—	8,522	2,153	6,368
Total Proved	67,092	10,536	19,692	6,989	2,335	27,541	7,084	20,457
Probable	107,028	26,614	24,410	11,230	—	44,774	11,366	33,409
Total Proved Plus Probable	174,120	37,150	44,101	18,218	2,335	72,315	18,450	53,865
China								
Proved:								
Developed Producing	584	—	101	—	17	466	153	313
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	584	—	101	—	17	466	153	313
Probable	283	—	48	6	—	229	75	153
Total Proved Plus Probable	867	—	149	6	17	695	228	466
Indonesia								
Proved:								
Developed Producing	—	—	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	1,132	—	517	167	—	448	138	310
Total Proved	1,132	—	517	167	—	448	138	310
Probable	216	—	107	—	—	109	44	65
Total Proved Plus Probable	1,349	—	624	167	—	557	182	375
Libya								
Proved:								
Developed Producing	17	—	6	1	—	10	—	10
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	17	—	6	1	—	10	—	10
Probable	3	—	—	—	—	3	—	3
Total Proved Plus Probable	20	—	6	1	—	13	—	13
Total								
Proved:								
Developed Producing	40,642	6,773	12,528	1,252	2,353	17,736	4,633	13,103
Developed Non-producing	2,928	329	701	139	—	1,759	451	1,309
Undeveloped	25,256	3,433	7,086	5,766	—	8,970	2,291	6,678
Total Proved	68,826	10,536	20,316	7,157	2,353	28,465	7,375	21,090
Probable	107,530	26,614	24,565	11,236	—	45,115	11,486	33,629
Total Proved Plus Probable	176,356	37,150	44,880	18,393	2,353	73,580	18,860	54,720
Total								

Future Net Revenue by Production Group
As at December 31, 2010
Forecast Prices and Costs

	Future Net Revenue Before Income Taxes (discounted at 10%/year)									
	Canada		China		Indonesia		Libya		Total	
	($000)	*($/boe)*	*($000)*	*($/boe)*	*($000)*	*($/boe)*	*($000)*	*($/boe)*	*($000)*	*($/boe)*
Proved										
Developed producing										
Light crude oil and NGL	4,002	32	415	80	—	—	9	46	4,425	34
Medium crude oil	1,458	22	—	—	—	—	—	—	1,458	22
Heavy crude oil	1,585	26	—	—	—	—	—	—	1,585	26
Natural gas	2,517	11	—	—	—	—	—	—	2,517	11
Coal bed methane	48	11	—	—	—	—	—	—	48	11
Bitumen	1,128	24	—	—	—	—	—	—	1,128	24
Developed non-producing										
Light crude oil and NGL	44	24	—	—	—	—	—	—	44	24
Medium crude oil	102	32	—	—	—	—	—	—	102	32
Heavy crude oil	422	36	—	—	—	—	—	—	422	36
Natural gas	394	13	—	—	—	—	—	—	394	13
Coal bed methane	2	8	—	—	—	—	—	—	2	8
Bitumen	—	—	—	—	—	—	—	—	—	—
Undeveloped										
Light crude oil and NGL	721	23	—	—	—	—	—	—	721	23
Medium crude oil	145	18	—	—	—	—	—	—	145	18
Heavy crude oil	612	24	—	—	—	—	—	—	612	24
Natural gas	144	2	—	—	171	6	—	—	316	3
Coal bed methane	5	3	—	—	—	—	—	—	5	3
Bitumen	1,346	8	—	—	—	—	—	—	1,346	8
Total Proved										
Light crude oil and NGL	4,766	30	415	80	—	—	9	46	5,190	32
Medium crude oil	1,706	22	—	—	—	—	—	—	1,706	22
Heavy crude oil	2,618	27	—	—	—	—	—	—	2,618	27
Natural gas	3,056	9	—	—	171	6	—	—	3,227	9
Coal bed methane	55	9	—	—	—	—	—	—	55	9
Bitumen	2,474	11	—	—	—	—	—	—	2,474	11
Probable										
Light crude oil and NGL	2,318	26	164	68	—	—	3	75	2,485	27
Medium crude oil	336	19	—	—	—	—	—	—	336	19
Heavy crude oil	711	25	—	—	—	—	—	—	711	25
Natural gas	645	7	—	—	32	6	—	—	676	7
Coal bed methane	2	9	—	—	—	—	—	—	2	9
Bitumen	4,670	6	—	—	—	—	—	—	4,670	6
Total Proved Plus Probable										
Light crude oil and NGL	7,084	29	579	76	—	—	11	50	7,674	30
Medium crude oil	2,042	21	—	—	—	—	—	—	2,042	21
Heavy crude oil	3,329	26	—	—	—	—	—	—	3,329	26
Natural gas	3,700	9	—	—	203	6	—	—	3,903	9
Coal bed methane	57	9	—	—	—	—	—	—	57	9
Bitumen	7,145	7	—	—	—	—	—	—	7,145	7

Pricing Assumptions

The pricing assumptions disclosed in the table below were derived using the industry averages prescribed by McDaniel & Associates Consultants Ltd, Sproule Associates Limited, and GLJ Petroleum Consultants Ltd.

	Crude Oil		Natural Gas			
	WTI (USD $/bbl)	Brent (USD $/bbl)	NYMEX (USD $/mmbtu)	NIT (Cdn $/GJ)	Inflation rates (1)	Exchange rates (2)
Historical:						
2006	66.22	65.14	7.23	6.62		0.882
2007	72.31	72.52	6.86	6.26		0.931
2008	99.65	96.99	9.04	7.70		0.937
2009	61.80	61.54	3.99	3.92		0.880
2010	79.46	79.42	4.39	3.91		0.971
Forecast:						
2011	87.13	86.88	4.50	3.93	1.018	0.962
2012	88.61	87.77	5.15	4.51	1.018	0.962
2013	89.76	88.49	5.61	4.96	1.018	0.962
2014	91.43	90.13	6.45	5.76	1.018	0.962
2015	93.90	92.59	6.82	6.08	1.018	0.962

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rate used to generate the benchmark reference prices.

Reconciliation of Gross Proved Reserves

	Light Crude Oil (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)	Total (mmboe)
Canada – Western Canada						
End of 2009	144.9	84.2	120.8	2,112.7	200.4	902.4
Revisions – Technical	(11.8)	4.0	1.8	(14.0)	(13.3)	(21.5)
Revisions – Economic	(0.1)	—	—	(74.4)	—	(12.5)
Purchases	1.3	0.3	—	205.6	—	36.0
Sales	(0.1)	—	—	(1.5)	—	(0.3)
Discoveries	0.5	0.1	—	32.2	0.6	6.6
Extensions	7.1	4.4	14.3	109.6	67.2	111.3
Improved recovery	0.2	4.0	0.5	0.7	—	4.8
Production	(8.4)	(9.3)	(27.2)	(185.0)	(8.1)	(83.8)
End of 2010	133.7	87.7	110.2	2,186.0	246.8	942.9
Canada – Atlantic Region						
End of 2009	92.9	—	—	—	—	92.9
Revisions – Technical	8.3	—	—	—	—	8.3
Revisions – Economic	—	—	—	—	—	—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	3.4	—	—	—	—	3.4
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	(17.1)	—	—	—	—	(17.1)
End of 2010	87.5	—	—	—	—	87.5
China						
End of 2009	8.9	—	—	—	—	8.9
Revisions – Technical	1.7	—	—	—	—	1.7
Revisions – Economic	—	—	—	—	—	—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—
Extensions	0.4	—	—	—	—	0.4
Improved recovery	—	—	—	—	—	—
Production	(3.9)	—	—	—	—	(3.9)
End of 2010	7.1	—	—	—	—	7.1
Indonesia						
End of 2009	—	—	—	—	—	—
Revisions – Technical	—	—	—	—	—	—
Revisions – Economic	—	—	—	—	—	—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	9.0	—	—	209.0	—	43.8
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	—	—	—	—	—	—
End of 2010	9.0	—	—	209.0	—	43.8
Libya						
End of 2009	0.2	—	—	—	—	0.2
Revisions – Technical	—	—	—	—	—	—
Revisions – Economic	—	—	—	—	—	—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	(0.1)	—	—	—	—	(0.1)
End of 2010	0.2	—	—	—	—	0.2

	Total		
	Crude Oil & NGL (mmbbls)	**Natural Gas (bcf)**	**Total Company (mmboe)**
End of 2009	652.2	2,112.7	1,004.4
Revisions – Technical	(9.2)	(14.0)	(11.5)
Revisions – Economic	(0.1)	(74.4)	(12.5)
Purchases	1.7	205.6	36.0
Sales	(0.1)	(1.5)	(0.3)
Discoveries	13.6	241.1	53.8
Extensions	93.4	109.6	111.7
Improved recovery	4.6	0.7	4.8
Production	(74.0)	(185.0)	(104.8)
End of 2010	682.3	2,395.0	1,081.5

Major additions to proved reserves in 2010 include:

- the extension through additional drilling and seismic interpretation of the Sunrise oil sands project that resulted in booking 56 mmbbls of bitumen to proved undeveloped reserves;
- the booking of 44 mmboe of natural gas and natural gas liquids to proved undeveloped reserves at Madura following the extension of the PSC;
- the acquisition in the Ram River area in the west central Alberta, which resulted in booking of proved natural gas reserves of 197 bcf; and
- the extension of proved reserves at Ansell in the Alberta Deep Basin area resulting in the booking of 17 mmboe of natural gas and natural gas liquids.

Reconciliation of Gross Probable Reserves

	Light Crude Oil (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)	Total (mmboe)
Canada – Western Canada						
End of 2009	45.4	16.0	31.3	524.4	1,093.9	1,274.0
Revisions – Technical	(4.8)	0.7	(5.2)	(19.1)	0.1	(12.5)
Revisions – Economic	—	—	—	(17.7)	—	(3.0)
Revisions – Transfer to Proved	(0.9)	(0.8)	(2.4)	(12.8)	(57.0)	(63.3)
Purchases	0.2	0.1	—	63.1	—	10.8
Sales	(0.1)	(0.1)	—	—	—	(0.1)
Discoveries	0.3	0.3	—	18.8	0.1	3.9
Extensions	0.9	—	8.8	21.0	2.6	15.8
Improved recovery	2.5	4.0	—	1.7	—	6.8
Production	—	—	—	—	—	—
End of 2010	43.4	20.2	32.4	579.4	1,039.8	1,232.4
Canada – Atlantic Region						
End of 2009	74.2	—	—	—	—	74.2
Revisions – Technical	(6.3)	—	—	—	—	(6.3)
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	—					—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	3.5	—	—	—	—	3.5
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	—	—	—	—	—	—
End of 2010	71.4	—	—	—	—	71.4
China						
End of 2009	3.9	—	—	—	—	3.9
Revisions – Technical	(0.6)	—	—	—	—	(0.6)
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	—					—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	—	—	—	—	—	—
End of 2010	3.3	—	—	—	—	3.3
Indonesia						
End of 2009	11.1	—	—	258.4	—	54.1
Revisions – Technical	—	—	—	(0.2)	—	—
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	(9.0)			(209.0)		(43.8)
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—
Extension	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	—	—	—	—	—	—
End of 2010	2.1	—	—	49.3	—	10.3
Libya						
End of 2009	0.1	—	—	—	—	0.1
Revisions – Technical	0.1	—	—	—	—	0.1
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	(0.2)					(0.2)
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	—	—	—	—	—	—
End of 2010	—	—	—	—	—	—

	Total		
	Crude Oil & NGL (mmbbls)	**Natural Gas (bcf)**	**Total Company (mmboe)**
End of 2009	1,275.9	782.8	1,406.4
Revisions – Technical	(16.1)	(19.3)	(19.3)
Revisions – Economic	(0.1)	(17.7)	(3.0)
Revisions – Transfer to Proved	(70.3)	(221.8)	(107.3)
Purchases	0.3	63.1	10.8
Sales	(0.1)	—	(0.1)
Discoveries	4.2	18.8	7.4
Extensions	12.3	21.0	15.8
Improved recovery	6.5	1.7	6.8
Production	—	—	—
End of 2010	1,212.6	628.7	1,317.4

Major changes to probable reserves in 2010 include:

- the transfer of reserves to proved for Sunrise of 56 mmbbls and Madura of 44 mmboe; and
- the acquisition in the Ram River area in west central Alberta, which resulted in booking of probable reserves of 11 mmboe.

Reconciliation of Gross Proved Plus Probable Reserves

	Light Crude Oil (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)	Total (mmboe)
Canada – Western Canada						
End of 2009	190.3	100.1	152.0	2,637.2	1,294.3	2,176.4
Revisions – Technical	(16.6)	4.7	(3.4)	(33.1)	(13.2)	(34.0)
Revisions – Economic	(0.2)	—	—	(92.1)	—	(15.5)
Revisions – Transfer to Proved	(0.9)	(0.8)	(2.4)	(12.8)	(57.0)	(63.3)
Purchases	1.5	0.4	—	268.7	—	46.8
Sales	(0.1)	(0.1)	—	(1.5)	—	(0.5)
Discoveries	0.8	0.4	—	51.0	0.7	10.5
Extensions	8.0	4.4	23.1	130.6	69.9	127.1
Improved recovery	2.7	8.0	0.5	2.4	—	11.6
Production	(8.4)	(9.3)	(27.2)	(185.0)	(8.1)	(83.8)
End of 2010	177.2	107.9	142.6	2,765.4	1,286.6	2,175.2
Canada – Atlantic Region						
End of 2009	167.1	—	—	—	—	167.1
Revisions – Technical	2.0	—	—	—	—	2.0
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	—					—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	6.9	—	—	—	—	6.9
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	(17.1)	—	—	—	—	(17.1)
End of 2010	158.9	—	—	—	—	158.9
China						
End of 2009	12.8	—	—	—	—	12.8
Revisions – Technical	1.1	—	—	—	—	1.1
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	—					—
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—
Extensions	0.4	—	—	—	—	0.4
Improved recovery	—	—	—	—	—	—
Production	(3.9)	—	—	—	—	(3.9)
End of 2010	10.4	—	—	—	—	10.4
Indonesia						
End of 2009	11.1	—	—	258.4	—	54.1
Revisions – Technical	—	—	—	(0.2)	—	—
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	(9.0)			(209.0)		(43.8)
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	9.0	—	—	209.0	—	43.8
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	—	—	—	—	—	—
End of 2010	11.1	—	—	258.3	—	54.1
Libya						
End of 2009	0.3	—	—	—	—	0.3
Revisions – Technical	0.1	—	—	—	—	0.1
Revisions – Economic	—	—	—	—	—	—
Revisions – Transfer to Proved	(0.2)					(0.2)
Purchases	—	—	—	—	—	—
Sales	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—
Extensions	—	—	—	—	—	—
Improved recovery	—	—	—	—	—	—
Production	(0.1)	—	—	—	—	(0.1)
End of 2010	0.2	—	—	—	—	0.2

	Total		
	Crude Oil & NGL (mmbbls)	**Natural Gas (bcf)**	**Total Company (mmboe)**
End of 2009	1,928.1	2,895.6	2,410.7
Revisions – Technical	(25.3)	(33.3)	(30.8)
Revisions – Economic	(0.1)	(92.1)	(15.5)
Revisions – Transfer to Proved	(70.3)	(221.8)	(107.3)
Purchases	2.0	268.7	46.8
Sales	(0.2)	(1.5)	(0.5)
Discoveries	17.8	260.0	61.2
Extensions	105.7	130.6	127.5
Improved recovery	11.2	2.4	11.6
Production	(74.0)	(185.0)	(104.8)
End of 2010	1,894.9	3,023.6	2,398.8

Undeveloped Reserves

Undeveloped reserves are attributed internally in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Probable undeveloped oil and gas reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. Classifications of reserves as proved or probable are only attempts to define the degree of uncertainty associated with the estimates. In addition, whereas proved reserves are those reserves that can be estimated with reasonable certainty to be economically producible, probable reserves are those reserves as likely as not to be recovered. Therefore, probable reserves estimates, by definition, have a higher degree of uncertainty than proved reserves.

Husky funds capital programs by cash generated from operating activities, cash on hand, equity issuance, and long-term and short-term debt. Decisions to develop proved undeveloped and probable reserves are based on various factors including economic conditions, technical performance and size of development program. Approximately 30% of Husky's proved undeveloped reserves are assigned to the Sunrise Energy Project. Phase I of this project was sanctioned in November 2010 and agreements have been reached on movement of bitumen to market as well as awarding major engineering and construction contracts. First production is expected in 2014. As at December 31, 2010, there are no material proved undeveloped reserves that have remained undeveloped for greater than five years.

Proved Undeveloped Reserves

First attributed	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Natural Gas (bcf)	Total Oil & NGL (mmbbls)
Year						
Prior	44.0	8.5	35.9	68.7	411.4	157.1
2008	0.7	0.1	2.1	—	79.2	2.9
2009	3.8	—	1.6	63.7	3.9	69.1
2010	12.8	0.1	—	0.6	212.5	13.5

Probable Undeveloped Reserves

First attributed	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Natural Gas (bcf)	Total Oil & NGL (mmbbls)
Year						
Prior	129.5	7.7	31.2	1,791.7	206.3	1,960.1
2008	0.8	—	0.1	—	23.0	0.9
2009	0.1	—	2.7	—	8.3	2.8
2010	3.9	0.3	—	0.1	25.3	4.3

Future Development Costs – Undiscounted

Forecast Prices and Costs

The Company expects to fund its future development costs by cash generated from operating activities, cash on hand, and long-term and short-term debt. The Company also has access to available amounts through its credit facilities on which it can draw funds and the ability to issue equity through its shelf prospectuses. The cost associated with this funding would not affect reserves and would not be material in comparison with future net revenues.

($million)	Canada		China		Indonesia	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2011	1,705	1,864	—	6	32	32
2012	1,475	1,932	—	—	80	80
2013	1,043	1,427	—	—	39	39
2014	545	1,398	—	—	6	6
2015	498	1,283	—	—	10	10
Remaining	4,058	12,649	17	17	—	—
Total	9,324	20,554	17	24	167	167

($million)	Libya		Total	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2011	1	1	1,738	1,904
2012	—	—	1,555	2,012
2013	—	—	1,082	1,466
2014	—	—	551	1,405
2015	—	—	508	1,293
Remaining	—	—	4,075	12,667
Total	1	1	9,510	20,746

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The Company has a significant amount of probable reserves assigned to Western Canada and the Atlantic Region. At current prices, these properties are economical. However, should crude oil and natural gas prices fall materially, these activities may not be economical and the Company could defer their implementation. In addition, reserves can be affected significantly by fluctuations in capital expenditures, operating costs, royalty regimes, and performance that are beyond the Company's control and which could impact future development decisions. See "Risk Factors".

Additional Information Concerning Abandonment and Reclamation Costs

The Company estimates the costs associated with abandonment and reclamation costs for surface leases, wells, facilities, and pipelines through its previous experience, where available, or by estimating such costs. With respect to abandonment and reclamation costs for surface leases, wells, facilities, and pipelines, the Company expects to incur these costs on approximately 26,600 net wells for a total undiscounted amount of $2.3 billion. Discounted at 10% per year, the total abandonment and reclamation costs, net of estimated salvage value, for wells is $589 million. This amount was deducted in estimating the future net revenue. Of the undiscounted portion of the total abandonment and reclamation costs, $134 million is expected to be paid in the next three years.

Production Estimates
Yearly Production Estimates for 2011

	Light Crude Oil (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)
Canada:					
Total gross proved	24.5	9.9	24.7	200.4	9.8
Total gross probable	1.4	0.4	0.9	7.0	0.1
Total gross proved plus probable	25.9	10.3	25.6	207.4	10.0
International:					
Total gross proved	2.9	—	—	—	—
Total gross probable	0.2	—	—	—	—
Total gross proved plus probable	3.1	—	—	—	—
Total					
Total gross proved	27.4	9.9	24.7	200.4	9.8
Total gross probable	1.6	0.4	0.9	7.0	0.1
Total gross proved plus probable	29.1	10.3	25.6	207.4	10.0

No individual property accounts for 20% or more of the estimated production disclosed.

Production History

The following table summarizes certain information related to the production, product prices received, royalties paid, production costs and resulting netback associated with our reserves data for the periods indicated below.

	Three Months Ended			
	Mar 31, 2010	Jun 30, 2010	Sept 30, 2010	Dec 31, 2010
Average Gross Daily Production:				
Canada – Western Canada				
Light crude oil and NGL (mbbl/day)	23.4	22.5	23.5	23.0
Medium Crude Oil (mbbl/day)	25.3	25.1	25.7	25.3
Heavy crude oil (mbbl/day)	76.4	74.6	72.4	74.6
Bitumen (mbbl/day)	22.6	21.5	21.9	23.1
Natural gas (mmcf/day)	523.7	503.9	505.5	494.2
Canada – Atlantic Region				
Light crude oil and NGL (mbbl/day)	49.9	45.0	50.8	41.3
China				
Light crude oil and NGL (mbbl/day)	11.0	11.2	10.1	10.8
Average Sales Price:				
Canada				
Light crude oil and NGL ($/boe)	74.73	71.66	71.73	78.90
Medium Crude Oil ($/boe)	67.60	61.89	59.13	63.40
Heavy crude oil ($/boe)	61.62	54.87	56.09	58.00
Bitumen ($/boe)	61.82	54.79	55.41	59.14
Natural gas ($/mcfge)	5.32	3.89	3.98	4.12
International				
Light crude oil and NGL ($/boe)	80.15	83.30	79.43	89.28

Production History (continued)

	Three Months Ended			
	Mar 31, 2010	Jun 30, 2010	Sept 30, 2010	Dec 31, 2010
Royalties Paid:				
Canada				
Light crude oil and NGL ($/boe)	19.15	17.68	15.51	13.18
Medium Crude Oil ($/boe)	12.96	11.53	10.07	9.91
Heavy crude oil ($/boe)	9.78	8.45	8.08	7.68
Bitumen ($/boe)	8.23	9.08	9.32	7.55
Natural gas ($/mcfge)	0.60	0.48	0.32	0.41
International				
Light crude oil and NGL ($/boe)	18.63	17.98	17.29	21.78
Production costs:				
Canada				
Light crude oil and NGL ($/boe)	11.30	12.66	9.79	13.46
Medium Crude Oil ($/boe)	16.62	17.91	15.63	14.87
Heavy crude oil ($/boe)	13.68	14.62	15.69	16.41
Bitumen ($/boe)	22.10	19.57	18.00	21.71
Natural gas ($/mcfge)	1.79	1.81	2.11	1.69
International				
Light crude oil and NGL ($/boe)	4.11	6.21	7.69	6.31
Netback (1):				
Canada				
Light crude oil and NGL ($/boe)	44.28	41.32	46.43	52.26
Medium Crude Oil ($/boe)	38.02	32.45	33.43	38.62
Heavy crude oil ($/boe)	38.16	31.80	32.32	33.91
Bitumen ($/boe)	31.49	26.14	28.09	29.88
Natural gas ($/mcfge)	2.93	1.60	1.55	2.02
International				
Light crude oil and NGL ($/boe)	57.41	59.11	54.45	61.19

Note:

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

Description of Major Properties and Facilities

Description of Major Properties and Facilities

Husky's portfolio of Upstream assets includes properties with reserves of light (30° API and lighter), medium (between 20° and 30° API), heavy (between 20° API and 10° API and is liquid) and bitumen (solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure), NGL, natural gas and sulphur.

Lloydminster Heavy Oil and Gas

Husky's heavy oil assets are primarily concentrated in a large producing region in the Lloydminster Alberta/Saskatchewan area. The Company maintains a land position of approximately two million gross acres within this area. Over 90% 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, Mervin, Marwayne, Lashburn, Gully Lake, Vermilion, Swimming, Morgan, Lindbergh, Aberfield, Mardsen, Epping, Furness and Rush Lake, and in the medium gravity crude oil producing fields of Wildmere and Wainwright. These fields contain accumulations of heavy crude oil at relatively shallow depths.

Husky currently produces from oil and gas wells ranging in depth from 450 m to 650 m and holds a 100% working interest in the majority of these wells. Production of heavy oil from the Lloydminster area uses a variety of techniques, including standard primary production methods, as well as steam injection, horizontal well technology and SAGD. Husky has increased primary production from the area through cold production techniques which utilize progressive cavity pumps capable of simultaneous production of sand and heavy oil from unconsolidated formations. Husky's gross heavy and medium crude oil production from the area totalled 80.4 mbbls/day in 2010. Of the total production, 59.8 mbbls/day was primarily production of heavy crude oil, including cold production techniques, 18.3 mbbls/day was production from Husky's thermal operations at Pikes Peak (cyclic steam), Bolney/Celtic (SAGD) and the Pikes Peak South pilot (SAGD), and 2.3 mbbls/day was from the medium gravity waterflooded fields in the Wainwright and Wildmere areas. Husky also produces natural gas from numerous small shallow pools in the Lloydminster region, and recovers solution gas produced from heavy oil wells. During 2010, Husky's gross natural gas production from the Lloydminster region averaged 34.4 mmcf/day.

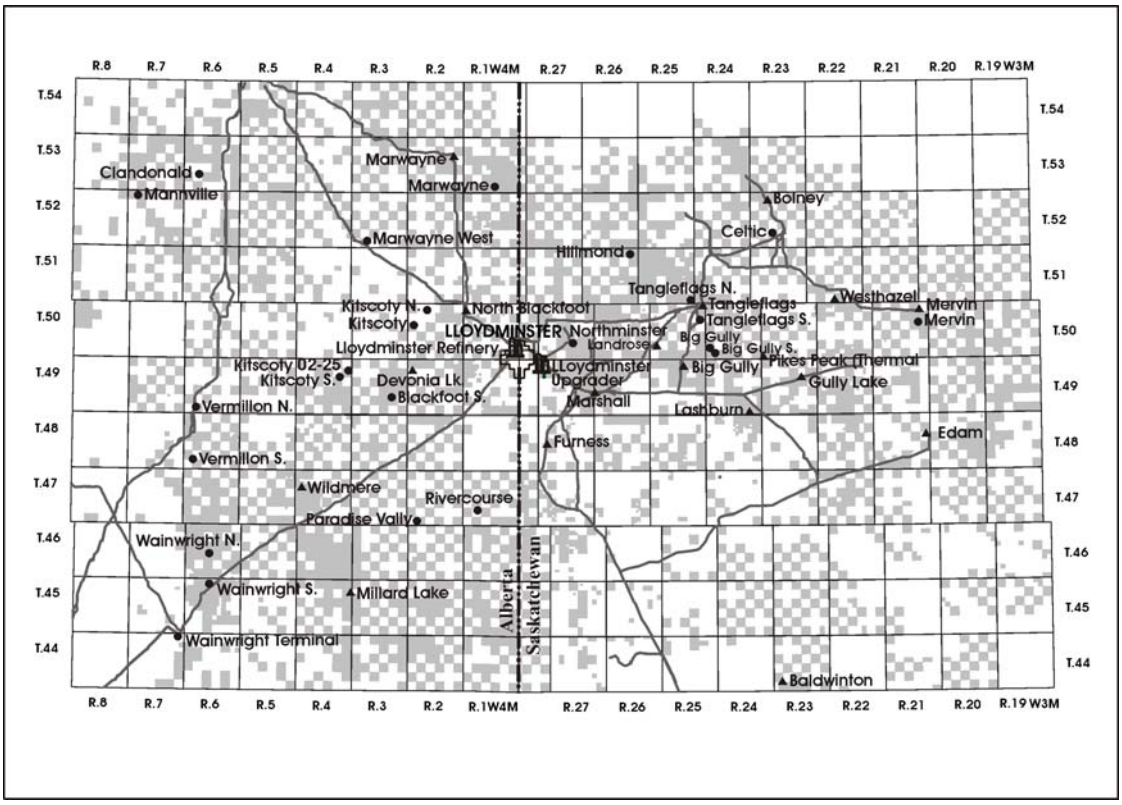
In the Lloydminster area, the Company owns and operates 19 oil treating facilities which are tied into the Husky heavy oil pipeline systems. These pipeline systems transport heavy crude oil from the field locations to the Husky Lloydminster asphalt refinery, the Husky Lloydminster Upgrader, the Enbridge Pipeline, the Express Pipeline and the Inter Pipeline Fund systems at Hardisty, Alberta.

The Company is focused on increasing its heavy oil production and believes that its undeveloped land position, coupled with the development and application of improved recovery technologies, will maintain heavy crude oil production in the Lloydminster area.

Non-Thermal EOR

Husky continued to operate two solvent EOR pilots through 2010 at Edam and Mervin. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with expected completion in the third quarter of 2011. This liquefied CO_2 is to be used in the ongoing piloting program. A microbial EOR pilot in Wainwright, Alberta continued in 2010 with nine wells continuing to show a substantial response eight months after treatment. A second pilot in Devonia Lake has commenced with two cycles of treatments completed. The preliminary results show a 20% increase in oil production.

Lloydminster Area



British Columbia/Foothills/Northwest Plains

Rainbow Lake District

Rainbow Lake, located approximately 700 km northwest of Edmonton, Alberta, is the site of Husky's largest light oil production operation in Western Canada. Husky operates a number of crude oil pools in the Rainbow basin, with an average working interest of 54%. Production in this district is derived from more than 50 oil and gas pools.

Husky uses secondary and tertiary oil recovery methods extensively in the Rainbow Lake district. These methods include injecting water, natural gas and NGL into various sections of 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 recoverable from discovered petroleum initially in-place from 50% to 70% in certain pools. Historically, only small volumes of gas and NGL have been marketed from the Rainbow Lake district prior to 2002. In 2003, the recovery of natural gas commenced from several pools. Husky uses horizontal drilling techniques, including the re-entry of existing well bores, to maintain the level of crude oil production and to increase recovery rates. Husky plans to continue exploration efforts to supplement its development initiatives in the Rainbow Lake district. Husky's gross (working interest) production from this area averaged 6.4 mbbls/day of light crude oil and NGL and 57.1 mmcf/day of natural gas during 2010.

At the end of 2010, Husky holds a 50% interest in, and operates, the Rainbow Lake processing plant. The processing design rate capacity of the plant is 85 mbbls/day of crude oil and water and 238 mmcf/day of raw gas. The extraction design capacity is 17.6 mbbls/day of NGL.

Husky acquired ExxonMobil's interests in the Rainbow Lake, Sierra, Ram River and Foothills areas on February 4, 2011. This acquisition added a total of 16.3 mboe/day of natural gas and 5.6 mbbls/day of crude oil and liquids production in February 2011. Total proved reserves for the acquisition were 104 mmboe with proved plus probable reserves of 113 mmboe. Approximately 57.0 mmcf/day natural gas and 5.0 mbbls/day oil and liquids production is in the Rainbow Lake/Sierra area with the remainder in the Ram River and Foothills areas. With this acquisition, Husky now has a 100% interest in the Rainbow Lake processing plant. The Company's oil and gas reserves disclosures at December 31, 2010 do not include additions from the acquisition.

Husky also has a 100% interest in a compression and dehydration facility at Bivouac that has a capacity to process 20 mmcf/day. In 2010, throughput at this facility averaged 16.9 mmcf/day. Husky's strategy in respect of this area is to drill and tie-in four to eight development wells per year to fully load the facility in 2011. Husky also holds a working interest in the EnCana Sierra gas plant in this same area which processes Husky gas from the Ekwan area. In 2010, gross production from the Ekwan asset was 9.8 mmcf/day natural gas and 35 bbls/day of NGL. The Company is active in both these areas with development and exploration drilling. Husky holds in excess of 200,000 acres of undeveloped land in these two areas.

Husky holds an interest in one non-operated property at Bistcho in the Rainbow Lake District. Husky's gross production from this property averaged 1.3 mmcf/day of natural gas and 2.7 bbls/day of liquid hydrocarbon in 2010.

Northern Alberta District

The Northern Alberta District surrounds the communities of Peace River and Slave Lake northwest of Edmonton, Alberta and is comprised of shallow gas production and primary heavy oil production.

Natural gas is produced from the Clearwater, Colony, McMurray and Wabasca or a combination of these zones that lie at a depth of approximately 400 to 500 m. In 2010, gross production from this district averaged 43 mmcf/day of natural gas. Husky's largest gas property in the district is at Muskwa, which consists of a 32 mmcf/day dehydrator facility, 6,255 horsepower of compression and a gathering system that collects natural gas from an area seven townships in size. Husky gross production from Muskwa averaged 7.0 mmcf/day in 2010.

The Company continued to expand its primary heavy oil production base in the Northern Alberta district averaging 4,830 bbls/day in 2010. Husky's McMullen field is located 40 km southwest of the Hamlet of Wabasca. Heavy oil production is expected to increase from 3,000 bbls/day to 4,000 bbls/day as a result of development program that started in late 2010 and carrying through into 2011. The Company is proceeding with an EOR pilot project in 2011 which includes construction of facilities, drilling of observation wells and a horizontal production well. In addition, Husky is preparing a 2012-2015 program to select the most profitable development scheme for the western part of the field, which is earmarked for SAGD or Cyclic Steam Soak, among other proved technologies. The Company received ERCB approval for a SAGD pilot in 2010.

Other primary heavy oil production tests are underway in both the Amadou, Cadotte and Twin Lake areas.

In 2011, Husky plans to continue to undertake recompletions and work-overs to increase production and add natural gas reserves at a low unit cost and take advantage of existing infrastructure and capacity.

High Level District

The High Level district of Alberta is approximately 600 km northwest of Edmonton, Alberta. Husky is the operator and holds close to 100% working interests in its properties. The area contains shallow Bluesky natural gas reservoirs that are characterized as low deliverability and low decline. In 2010, gross production from this area averaged 11.5 mmcf/day of natural gas.

Ram River District

The Ram River district 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 three high deliverability natural gas wells, capable of combined raw gas production of 29 mmcf/day. Husky holds a 34% interest in one unitized well, and a 24% and 50% interest, respectively, in two non-unit wells, and acts as the contract operator of the Blackstone field. Production from the area is processed at the Ram River gas plant.

Husky holds an average 72% interest in and operates 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 2010, the plant operated at approximately 45% of its approved inlet raw gas capacity. The Ram River plant processes in excess of 10% of the Company's total gross natural gas production. This includes an average of 29 mmcf/day of Husky gross production from the Blackstone, Brown Creek, Cordel and Stolberg fields and an average of 9 mmcf/day of Husky gross production from Ricinus, Clearwater/Limestone and Benjamin fields. In addition the Company processes third party volumes. Gross production from the Strachan, Ferrier and North Blackstone areas, which is processed at other gas plants, averaged 17 mmcf/day of natural gas, bringing total Husky gross production of natural gas from the Ram River district to 55 mmcf/day in 2010. The Company's 2011

plans for the Ram River district include continued development drilling in North Blackstone area.

Husky has a sour gas pipeline network that supports the Ram River plant. Husky operates a network of 845 km of sour gas pipelines in the Ram River district and holds a 30% interest in 684 km 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 km from the Ram River plant.

Husky believes that the Ram River plant and the extensive infrastructure of gathering pipelines, transmission systems and rail lines, which support the plant, represents a strategic base for natural gas exploration and development planned in this part of the foothills region.

In addition, other companies are active in pursuing exploration and production activities in this area which may provide additional opportunities for generating third party natural gas processing revenue. In 2010, net processing income was $5.3 million down from $10.5 million in 2009 due, in part, to lower Shell Tay River natural gas volumes and acquisitions of non-owner gas production by plant owners in 2010.

Kaybob District

The Kaybob district consists of land located in the Fox Creek region of Alberta and is divided into three areas. The Kaybob South Triassic Unit 1 (40.5% working interest), Kaybob South Triassic Unit 2 (26.8% working interest), and non-unit lands (various working interests from gross overriding royalty to 100% working interest).

Husky has a 13.2% working interest in the sour gas portion and a 17.8% working interest in the sweet gas portion of the plant. The Company also has various working interests in sweet gas gathering and compression facilities in the area. During 2010, Husky gross production from this district was 661 bbls/day of crude oil and NGL and 9.8 mmcf/day of natural gas.

Alberta/British Columbia Plains District

Boundary Lake Area

Husky holds a 50% working interest in the Boundary Lake Gas Unit and a 34% and 19% interest in the Boundary Lake Oil Unit 1 and 2, respectively, in northeast British Columbia. Husky natural gas production from this area is derived from five Belloy sour gas pools and is processed at the nearby Boundary Lake processing plant. Husky gross production from this area was 6.3 mmcf/day of natural gas and 1,081 bbls/day of crude oil and NGL during 2010.

Valhalla and Wapiti Area

Husky holds an approximate 30% interest in three Valhalla oil units, a 100% interest in the Valhalla non-unit waterflood wells and a 100% interest in the Wapiti property. Production is primarily from the Doe Creek and Cardium zones and consists of light crude oil, NGL and natural gas. Husky gross production from these properties averaged 2,153 bbls/day of crude oil and NGL and 7.5 mmcf/day of natural gas in 2010. In 2011, the Company plans to continue to optimize the Valhalla assets to improve waterflood conformance and arrest declining production in the main Doe Creek I pool.

Kakwa Area

Husky holds an average 60% working interest in oil and gas processing facilities and associated oil and gas gathering systems in the Kakwa area. Husky gross production from this area was 8.1 mmcf/day of natural gas and 458 bbls/day of crude oil and NGL in 2010. In 2011, Husky plans to drill three multi-zone Exploration wells to define the extent of this significant resource in the Kakwa area.

Lynx, Copton and Grande Cache Areas

During 2010, Husky average gross production from this asset was 11.6 mmcf/day of natural gas. Although there are a number of future drilling opportunities in this area, capital has been re-directed to oil and liquids rich gas opportunities.

Foothills West District

Caroline Area

Husky holds a 14% working interest in the 32,000 acre Caroline natural gas field located approximately 97 km northwest of Calgary. The field has a high proportion of NGL and as a result the economics of this field are enhanced.

Husky also holds a 14% interest in the Caroline sour gas processing facility. The plant is presently running at 57% utilization based on design capacity and is processing approximately 107 mmcf/day of total plant natural gas sales and 10.6 mbbls/day of NGL. Husky gross production from the Unit was 1,101 bbls/day of NGL and 2.4 mmcf/day of natural gas in 2010.

Edson Area

Husky holds and operates an average 85% working interest in two gas processing facilities and associated gas gathering systems in the Edson area. Husky's gross production from these properties averaged 41.2 mmcf/day of natural gas and 1,972 bbls/day of NGL in 2010. The 2010 development drilling program consisted of 30 gross wells. The Company plans to drill 41 gross gas wells and tie in 50 gross gas wells in 2011 to grow natural gas sales production by 17 mmcf/d and 825 bbls/d NGLs by September, 2011.

Sikanni and Federal Areas

Husky holds interests in properties in the Sikanni and Federal areas of northeast British Columbia, which averaged gross production of 13 mmcf/day of natural gas from 10 wells in 2010. Husky natural gas production flows through its gathering systems for processing at third party plants at Sikanni and McMahon. A pilot test commenced in 2010 to de-water previously watered out structures which contain 60-80% of the original gas reserves which were trapped at high pressure by encroaching water.

Graham Area

Husky holds a 40% working interest in land in the Graham area of northeast British Columbia. Husky gross production from this area in 2010 averaged 4.1 mmcf/day of natural gas. Production from the property is from one Halfway and seven Baldonnel pools. Husky also holds 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 43% capacity. The Company holds a 33.2% interest in the gas treating unit, 28.2% interest in the amine unit and 28% interest in the sulphur unit.

Grizzly Valley and Bullmoose Area

Husky holds a 33-50% working interest in nine wells in this exploration area. Husky is currently flowing natural gas production through interruptible capacity in the Spectra (Duke) system and averaged 22.3 mmcf/day of gross natural gas production from this area in 2010. Although the Company has a number of drilling opportunities in this area, activity in 2011 has been reduced significantly due to low natural gas commodity prices to re-focus capital spending on oil and liquids rich gas opportunities.

East Central Alberta

Red Deer and Hussar Districts

The core of the Red Deer and Hussar districts is located between Calgary, Drumheller and Sylvan Lake. Husky operates 21 facilities with gas gathering systems in these districts. Husky's gross production from this area averaged 62 mmcf/day of natural gas and 2.3 mbbls/day of crude oil and NGL in 2010. In the Hussar District , Husky intends to focus on light crude oil development in the Carolside area and is currently reviewing ASP potential which includes petrophycial studies being completed in the second quarter of 2011. In the Red Deer District, the focus will be on acquisition and development of oil resource properties. Husky's 2011 development plan for its gas properties has been significantly reduced due to lower returns in the current price environment.

Provost District

The centre of the Provost district is approximately 240 km southeast of Edmonton and includes a large area in both Alberta and Saskatchewan. It is predominantly a medium crude oil area that averaged gross production of

12.9 mbbls/day of crude oil and 14.0 mmcf/day of natural gas in 2010. The main producing zones are from Mannville for oil and gas and Viking for oil. Husky continues to reduce operating costs and improve oil recovery through the application of horizontal drilling and new central processing. In 2011, Viking oil drilling will target high production reservoirs utilizing horizontal drilling with multiple fracturing treatments. The new $22 million Windy Lake Oil Battery is on track for first oil in the first quarter of 2011 with an expected 700 boe/day. The new facility will allow for reduced operating costs by substantially reducing trucking cost and increased hydrocarbon recovery due to more efficient operations. Husky holds a large land position and maintains close to a 100% working interest in most of the 25 facilities it operates.

Athabasca District

The Athabasca district extends approximately 175 km north of Edmonton, and from the Alberta-Saskatchewan border in the east, to the Alberta foothills in the west. The predominant area target has traditionally been shallow gas, ranging from 450 m to 900 m in the multi-zone Palaeozoic Mannville formation, but more recently Husky has applied horizontal wells with multiple fracturing treatments for oil in the Viking formation, with quality results. The main producing areas are Athabasca, Craigend and Redwater. Husky operates 32 facilities with pipeline systems and holds an average working interest of 90% in the producing wells. Husky intends to continue developing the gas areas with infill and step out wells to optimize recovery. Horizontal oil drilling in the Viking formation along with vertical oil well development in several other areas will be preferentially applied to maximize capital returns at current oil prices. Husky's gross production from this area averaged 29.2 mmcf/day of natural gas and 827 bbls/day of crude oil in 2010.

Southern Alberta and Southern Saskatchewan

Southern Saskatchewan District

Husky is a prominent operator in southern Saskatchewan primarily producing medium gravity crude oil, with some natural gas and light crude oil. Husky net production from properties in this district averaged 13.7 mbbls/day of crude oil and 25.2 mmcf/day of natural gas during 2010.

Husky operates 28 oil batteries and eight gas facilities in the southern Saskatchewan district. The oil pools in this area are exploited using pressure maintenance and waterflood recovery operations.

At Gull Lake, the ASP flood is fully operational and one full year of injection has been achieved. Production rate increases are anticipated in the third quarter of 2011.

Weir Hill, an oil battery and gathering system is nearing completion for a start-up in March 2011 to reduce trucking costs and enable well optimizations.

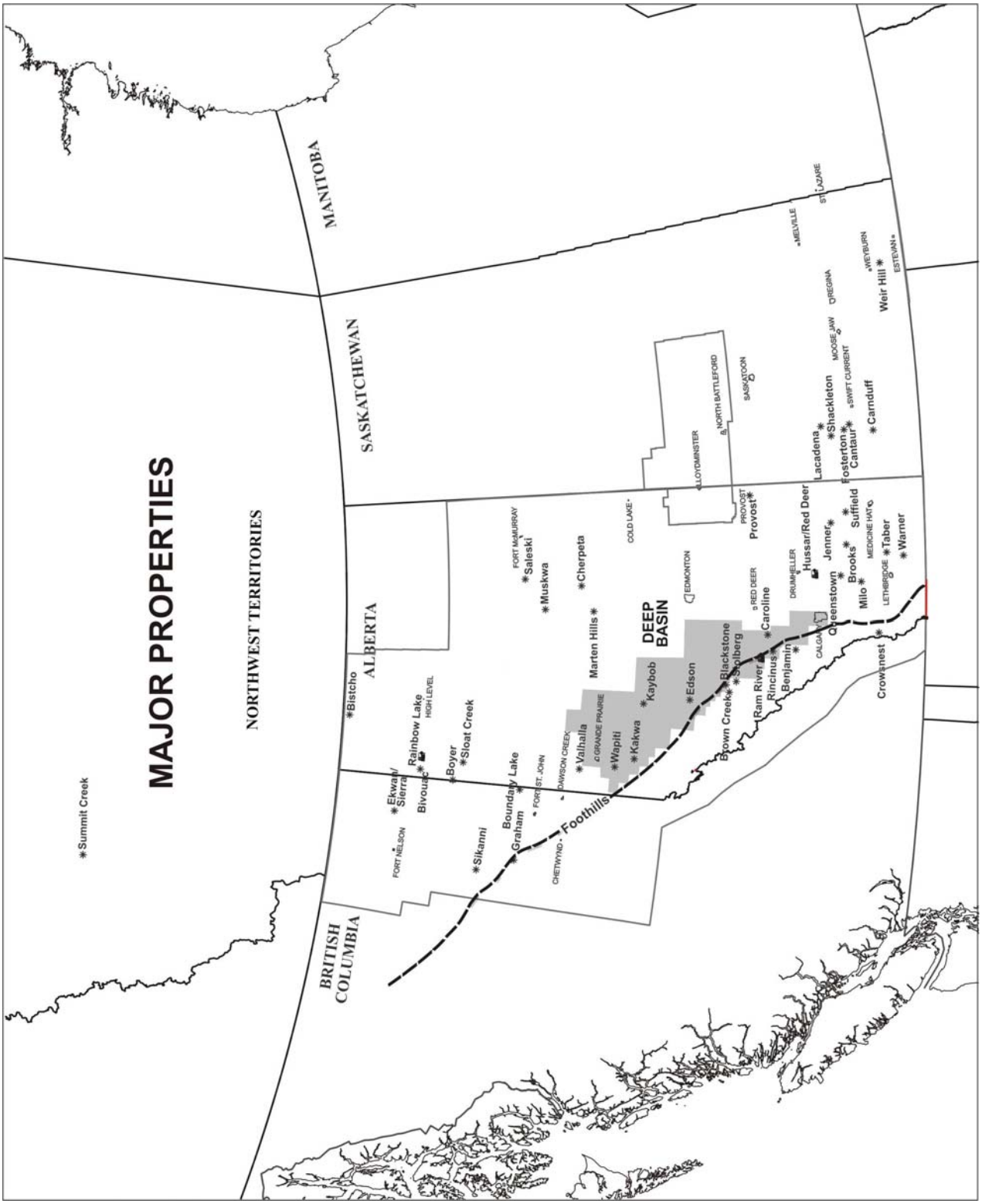
The Fosterton ASP flood is currently in final approval stage. It is expected that facility construction will begin in the second quarter of 2011. Facility completion and full ASP injection is expected to commence in the third quarter of 2012. Husky is the operator and holds a 62.4% working interest in this project.

Southern Alberta District

Husky has a significant presence in southern Alberta with a field office in Taber and additional major operations near Brooks and Milo. Total net production from this district averaged 8.5 mbbls/day of crude oil and 21.9 mmcf/day of natural gas during 2010.

Husky operates 20 oil facilities and three natural gas facilities in the area with an average working interest of 95%. Oil production is mainly medium gravity crude with the majority of reserves being supported by waterfloods or active aquifers. Natural gas production is both associated and non-associated from a mixture of deep and shallow formations.

At Warner, near Taber, Husky is in the fourth year of operating an ASP flood to increase recovery from the Cretaceous Mannville reservoir and Husky has recently implemented a second ASP flood at Crowsnest which just completed its third year of operation.


MAJOR PROPERTIES
NORTHWEST TERRITORIES
MANITOBA
SASKATCHEWAN
ALBERTA
BRITISH COLUMBIA
DEEP BASIN
Foothills
Summit Creek
Bistcho
Ekwan/ Sierra
Bivouac
Rainbow Lake
HIGH LEVEL
Boyer
Sloat Creek
Sikanni
Boundary Lake
Graham
FORT NELSON
FORT ST. JOHN
CHETWYND
DAWSON CREEK
Valhalla
GRANDE PRAIRIE
Wapiti
Kakwa
Kaybob
Marten Hills
Cherpeta
Muskwa
Saleski
FORT McMURRAY
COLD LAKE
EDMONTON
Edson
Brown Creek
Blackstone
Swanberg
Ram River
Caroline
RED DEER
Rincinus
Benjamin
CALGARY
DRUMHELLER
Hussar/Red Deer
PROVOST
Provost
LLOYDMINSTER
NORTH BATTLEFORD
SASKATOON
Queenstown
Jenner
Brooks
Milo
Suffield
MEDICINE HAT
LETHBRIDGE
Taber
Warner
Crowsnest
Lacadena
Shackleton
MOOSE JAW
SWIFT CURRENT
Fosterton
Cantaur
Carnduff
REGINA
MELVILLE
ST. LAZARE
WEYBURN
Weir Hill
ESTEVAN

Oil Sands

Tucker

At Tucker, an in-situ SAGD oil sands project located 30 km northwest of Cold Lake, Alberta, production commenced at the end of 2006. Production from the initial 32 well pairs was slow to ramp-up largely due to the position of some wells relative to the water saturation zone of the reservoir. At the end of 2007, eight new well pairs had been completed. Optimization strategies were conducted through 2008 on existing well pads and the eight new well pairs on Pad C resulting in encouraging production response. Throughout 2009, work continued to optimize reservoir operating strategy with production improving throughout 2009 to a December 2009 average rate of 5 mbbls/day (gross). Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by remediating older wells with innovative new stimulation techniques, drilling new wells and initiating new start up procedures and the results will be evaluated over the next six to twelve months. Husky drilled 32 wells (16 well pairs) in 2010 and is expecting to drill eight wells (four well pairs) in 2011. Three well pairs commenced production in late September 2010 and are exceeding the performance of well pairs previously drilled. Production at Tucker in December 2010 was 6.1 mboe/day. Several applications to the ERCB have been approved or are proceeding for additional drilling and field development through to 2015.

Sunrise

In early 2008, Husky and BP created an integrated North American oil sands business consisting of Upstream and Downstream assets based on Husky's Sunrise holdings and BP's Toledo, Ohio, U.S. Refinery. The business consists of a 50/50 partnership to develop the Sunrise oil sands project contributed and operated by Husky and a 50/50 limited liability company for the Toledo Refinery contributed and operated by BP.

FEED for Phase I of the Sunrise in-situ SAGD oil sands project, located in the Athabasca region of northern Alberta, was completed in December 2009. During 2010, the Partnership reached an agreement with Enbridge, IPF and Keyera on the movement of diluted bitumen to market and transportation of diluent to the Sunrise oil sands site. Project sanction for Phase I was announced in late 2010 and Husky awarded major engineering and construction contracts to Snamprogetti Canada for the central processing facilities and to Worley Parsons for the field facilities. Development drilling commenced in the first quarter of 2011. First production for Phase I is planned for 2014.

The Sunrise project was approved by the ERCB in December 2005. An amendment application was submitted in March of 2007, which outlines changes and optimizations resulting from ongoing depletion planning and FEED. Amendment approvals from the ERCB were received in December 2008 and approval from Alberta Environment was received in the first quarter of 2009. A second amendment to optimize the central plant facility design was filed with the regulators in July 2009 and approval was received from both the ERCB and Alberta Environment in December 2009. Work is ongoing with various industry participants on regional infrastructure issues, an air strip became operational in 2008 and a new access road was completed in 2010. Phase I will produce 60 mbbls/day of the full project which Husky currently has regulatory approval for of 200 mbbls/day once all phases are constructed and operational.

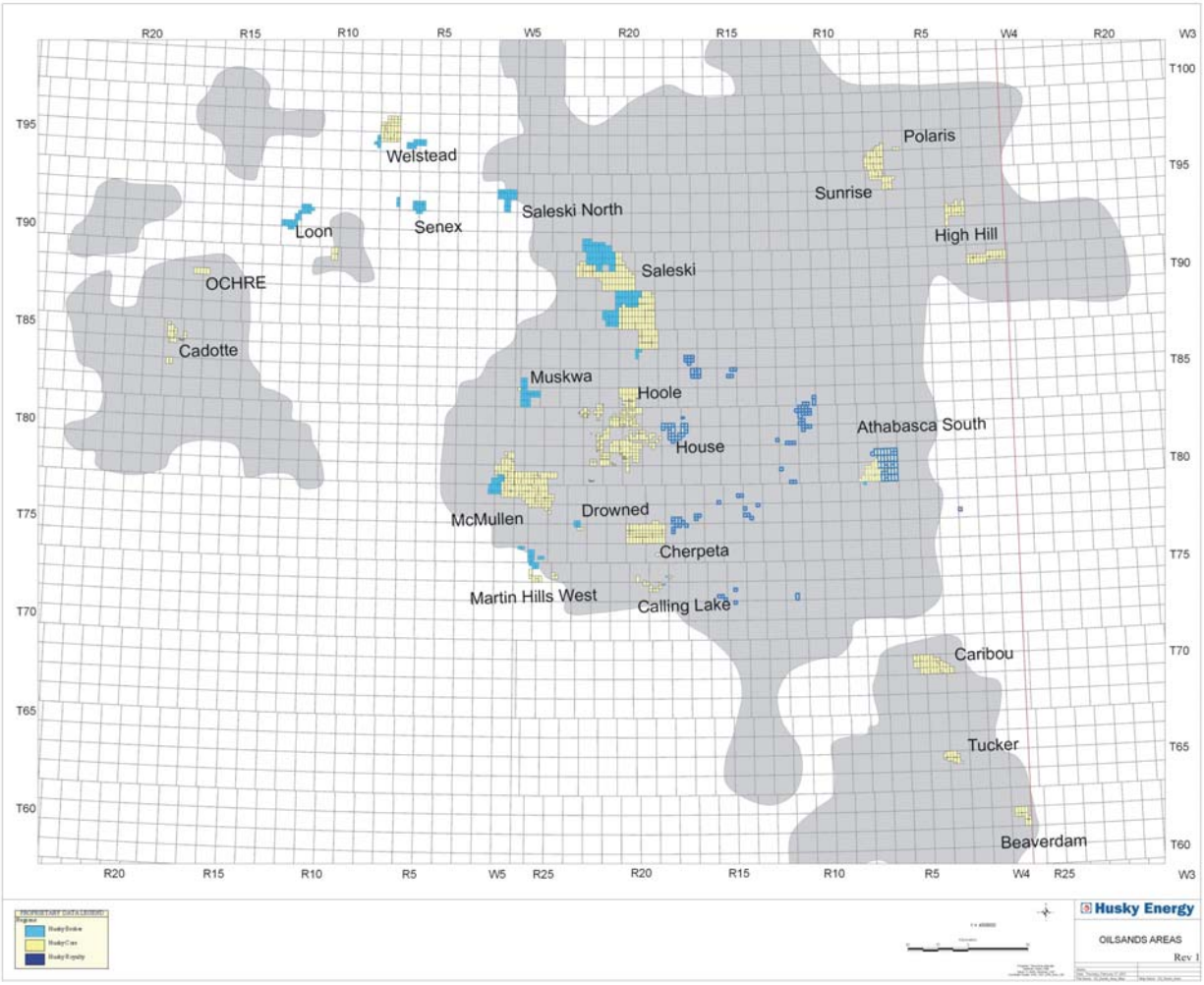
Husky has initiated conceptual engineering for subsequent phases and is expecting a comprehensive full field development plan to be established by the end of 2011.

Undeveloped Oil Sands Assets

Husky holds 448,000 acres in eight undeveloped oil sands leases. Husky is progressing the largest assets (Saleski and McMullen) towards pilots of thermal production in the first half of this decade, with an aim to achieve commerciality within the next ten years.

In Saleski, just north of Wabasca and bordering Laricina's thermal pilot area, Husky is drilling over 20 wells per year to high-grade its acreage and select an initial production area by 2013. Depending on the results of the ongoing Laricina test, the Company may progress a commercial demonstration pilot of up to 10 mbbls/day by 2016-17.

In alignment with the financing strategy to divest non-core assets that do not affect production or reserves, Husky sold its Polaris North leases, northwest of Sunrise, in the first quarter of 2011. Further portfolio activity will focus on accelerating the development of our other oil sands leases (e.g. Caribou, Polaris South and Athabasca South) which are located in areas with ongoing production using proved production technologies (CNRL's Primrose, Suncor's Firebag, Statoil's Kai Kos Deseh, respectively).


R20
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Welstead
Loon
Senex
Saleski North
Polaris
Sunrise
High Hill
OCHRE
Saleski
Cadotte
Muskwa
Hoole
House
Athabasca South
McMullen
Drowned
Cherpeta
Martin Hills West
Calling Lake
Caribou
Tucker
Beaverdam
R25
Husky Energy
OILSANDS AREAS
Rev 1

Northwest Territories ("NWT")

In the NWT, Husky has a focused land position in the Central Mackenzie Valley consisting of two Exploration Licenses ("EL"). In addition, the Company has interests in several freehold blocks and two Significant Discovery Licences ("SDL"). During 2010, Husky completed the reclamation of staging areas used in previous drilling and seismic programs and well sites, including abandonment of four previously suspended exploration wells. Husky holds a 40% to 75% working interest in the NWT lands. Exploration success to date has not secured sufficient hydrocarbon volumes to meet the threshold for commercial development. No activity is planned for 2011.

Atlantic Region

Husky's offshore East Coast exploration and development program is focused in the Jeanne d'Arc Basin on the Grand Banks, which contains the Hibernia, Terra Nova, White Rose and North Amethyst oil fields. Husky holds ownership interests in the Terra Nova, White Rose and North Amethyst oil fields as well as in a number of smaller undeveloped fields in the central part of the basin and also holds significant exploration acreage. Husky also holds a portfolio of exploration licenses in offshore Greenland.

White Rose Oil Field

The White Rose oil field, which Husky operates is located 354 kilometres off the coast of Newfoundland and Labrador approximately 48 kilometres east of the Hibernia oil field on the eastern section of the Jeanne d'Arc Basin.

First oil was achieved at White Rose in November 2005. The White Rose field was the third oil field developed offshore Newfoundland & Labrador. The field currently has eight production wells, ten water injectors, and three gas injectors. Husky continues to look at means of enhancing oil recovery from the core field. During 2010, gross production from the White Rose field averaged 31.2 mbbls/day.

On May 31, 2010, first oil was achieved from North Amethyst, the first of a number of potential satellite field expansions for the White Rose area. The field is located approximately 6 kilometres southwest of the *SeaRose FPSO* production vessel. Production flows from North Amethyst to the *SeaRose FPSO* through a series of subsea flowlines. During 2010, gross production from North Amethyst averaged 7.0 mbbls/day. As of early January 2011, the field had two production wells and two water injectors online. Development drilling will continue through to 2013. A total of 11 wells are currently planned for the main North Amethyst development.

In December 2009, Husky announced the results of statigraphic well testing of a second, deeper formation at North Amethyst. Drilled in 2008, the well encountered an oil bearing zone with approximately 55 metres of net pay in the Hibernia sandstones. Husky expects to file necessary documents to develop this resource in 2011. Further assessment of the Hibernia sandstone potential beneath the main White Rose field is continuing.

Husky continues to progress plans for a staged development of the West White Rose field. In August 2010, the Company received regulatory approval for a 2-well pilot project to be drilled from existing infrastructure in the White Rose field. These wells will provide additional information on the reservoir to refine development plans for the full West White Rose field. A production licence was received in the fourth quarter of 2010, and first production is anticipated mid-2011. Drilling of the first well commenced shortly after regulatory approval was received in August 2010 and will be completed and brought into production in 2011.

The South White Rose extension, the smallest of the satellite tie-back developments, was approved by the federal and provincial governments in September 2007. Husky continues to look at this area in the context of all three tie-back opportunities with a view toward optimizing the overall tieback program.

Husky has and will continue to consider technical options for the development of natural gas in the Jeanne d'Arc Basin. In parallel and pending rig availability, exploration and delineation drilling will improve estimates of the resource base ahead of any future development.

Husky is the operator of the White Rose field and satellite tiebacks including North Amethyst and West White Rose, with a 72.5% working interest in the core field, and a 68.875% working interest in the satellite fields. Other partners include Suncor (formerly Petro-Canada) 27.5% core field, and 26.125% satellites, and Nalcor Energy, the energy corporation of Newfoundland and Labrador, with 5% in the White Rose satellite fields.

Terra Nova Oil Field

The Terra Nova oil field is located approximately 350 kilometres southeast of St. John's, Newfoundland & Labrador in 91 to 100 metres of water. The Terra Nova oil field is divided into three distinct areas, known as the

Graben, the East Flank and the Far East. Production at Terra Nova commenced in January 2002.

Effective December 1, 2010, Husky's working interest in the field increased to 13.00% from 12.51%, following completion of a redetermination process that commenced following field payout as per the conditions of the Terra Nova Development and Operating Agreement. This resulted in a one time payment to Husky of $31.8 million, net of tax, representing Husky's share of production during the interim period from the start of the redetermination period to December 1, 2010. The change in working interest will also increase Husky's share of remaining reserves at Terra Nova by approximately one million barrels.

Husky's gross share of production in 2010 from the Terra Nova field was 3.1 mmbbls or an average 8.55 mbbls/day.

As at December 31, 2010, there were 14 development wells drilled in the Graben area, eight production wells, three water injection wells and three gas injection wells. In the East Flank area there were 11 development wells including six production wells and five water injection wells. There is one extended reach producer and an extended reach water injection well in the Far East Central area. Terra Nova completed the latest phase of the development drilling program in August 2007. The Terra Nova Owners have signed a new rig sharing agreement and drilling operations are expected to resume in early 2011.

East Coast Exploration

Husky believes that the areas offshore Canada's East Coast have exploration potential, and that the Company's position there will provide growth opportunities for light crude oil and natural gas development in the medium to long-term. Husky presently holds working interests ranging from 5.8% to 73.125% in 16 significant discovery license areas (SDAs) in the Jeanne d'Arc Basin, as well as interests ranging from 17.1% to 19.4% in five SDLs on the Labrador Shelf, a region that could be significant, in the long-term, for natural gas reserves.

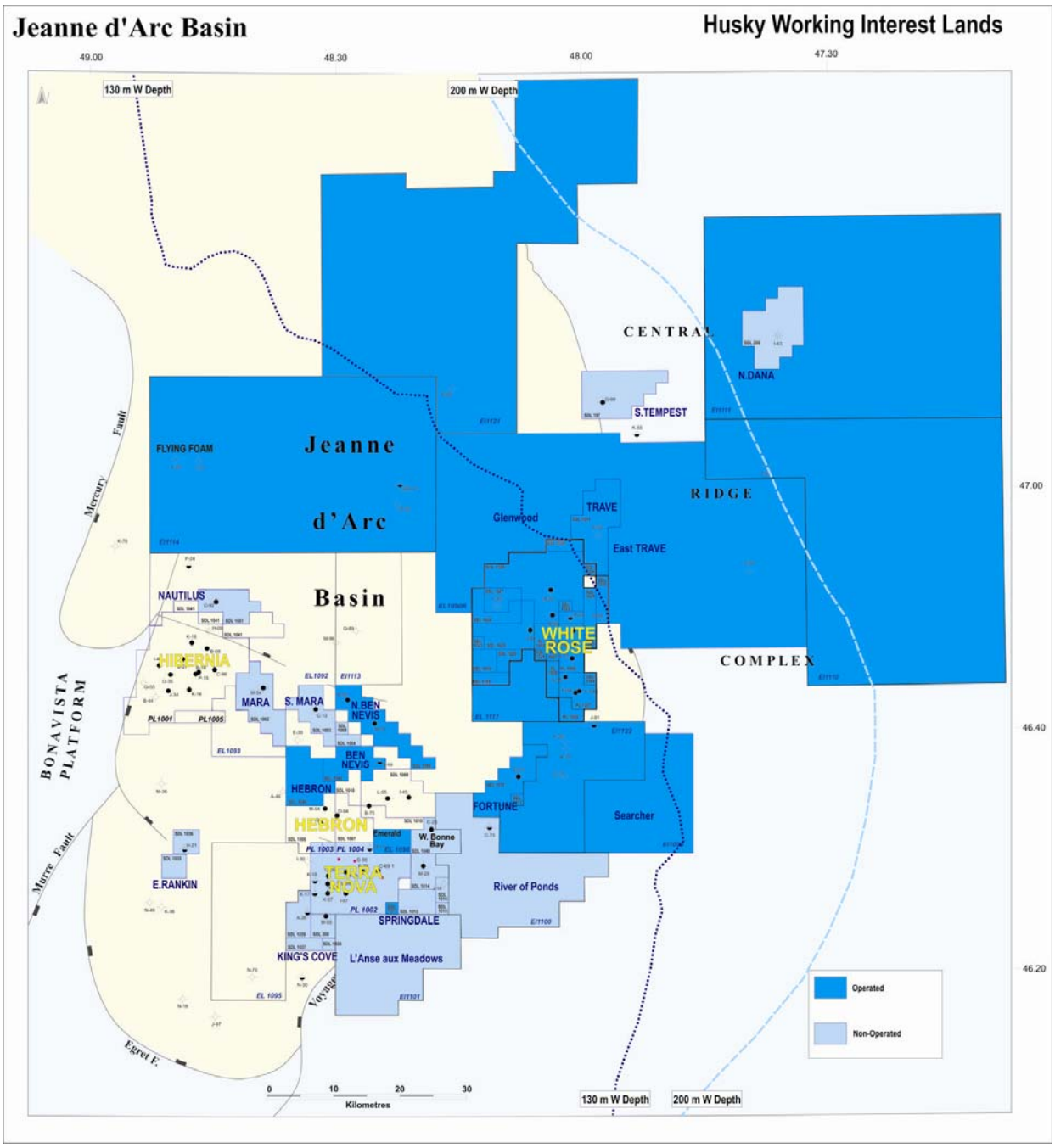
In February 2010, Husky and its partner received an SDL for the Mizzen prospect in the Flemish Pass. A second, adjacent SDL was acquired in November 2010. Husky is a 35% partner in both licenses.

Husky also received exploration rights to three additional parcels of land during the Canada-Newfoundland and Labrador Offshore Petroleum Board's November 2010 land sale. The exploration properties are adjacent to other Husky land holdings in the Jeanne d'Arc Basin and Flemish Pass.

As of December 31, 2010 Husky held a working interest in 17 Exploration Licences ("EL") offshore Newfoundland primarily in the Jeanne d'Arc Basin. Husky is the operator of 13 ELs, of which it holds a 100% interest in six. Husky holds working interests ranging from 35% to 72.5% in the remaining three operated and four non-operated ELs. Husky also holds, and is the operator of, two ELs offshore Labrador.

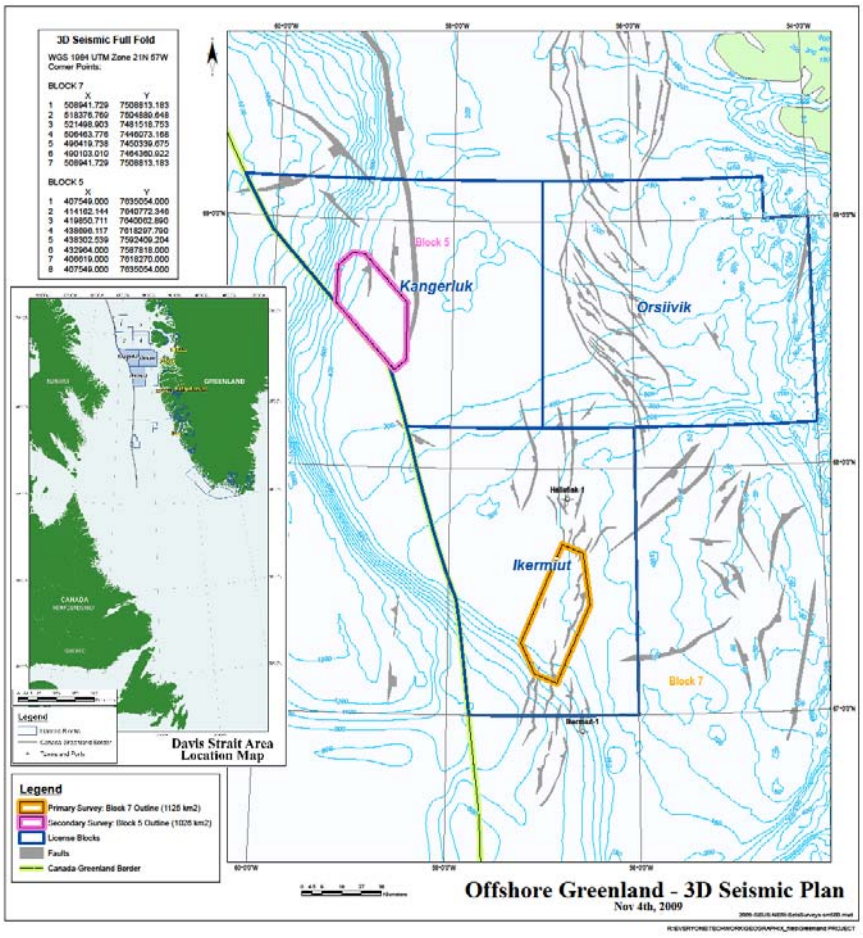
Husky continues to evaluate drilling opportunities in the context of its full portfolio of East Coast land holdings, and plans to drill one to two exploration wells in 2011. Results of the Glenwood H-69 exploration well, drilled in the first quarter of 2010, continue to be evaluated.

Two-Dimensional seismic surveys were carried out in the summer of 2010 on land holdings in the Sydney Basin and offshore Labrador including 3,000 kilometres of seismic on a new exploration parcel in the Sydney Basin, and a 2,500 kilometre survey on EL1106 and EL1108 offshore Labrador. Pending regulatory and partner approvals, Husky is considering a 3-D seismic acquisition program for offshore Labrador in 2011 or 2012.


Jeanne d'Arc Basin
Husky Working Interest Lands
49.00
48.30
48.00
47.30
47.00
46.40
46.20
130 m W Depth
200 m W Depth
CENTRAL
RIDGE
COMPLEX
N.DANA
S.TEMPEST
FLYING FOAM
Jeanne
d'Arc
Basin
Mercury Fault
Glenwood
TRAVE
East TRAVE
NAUTILUS
HIBERNIA
WHITE ROSE
MARA
S. MARA
N BEN NEVIS
BEN NEVIS
HEBRON
FORTUNE
Searcher
Emerald
W. Bonne Bay
TERRA NOVA
River of Ponds
SPRINGDALE
KING'S COVE
L'Anse aux Meadows
E.RANKIN
BONAVISTA PLATFORM
Murre Fault
Egret F.
Voyage
PL1001
PL1005
EL1093
EL1092
EI1113
PL 1003
PL 1004
PL 1002
EL 1095
EI1100
EI1101
0
10
20
30
Kilometres
Operated
Non-Operated

Greenland

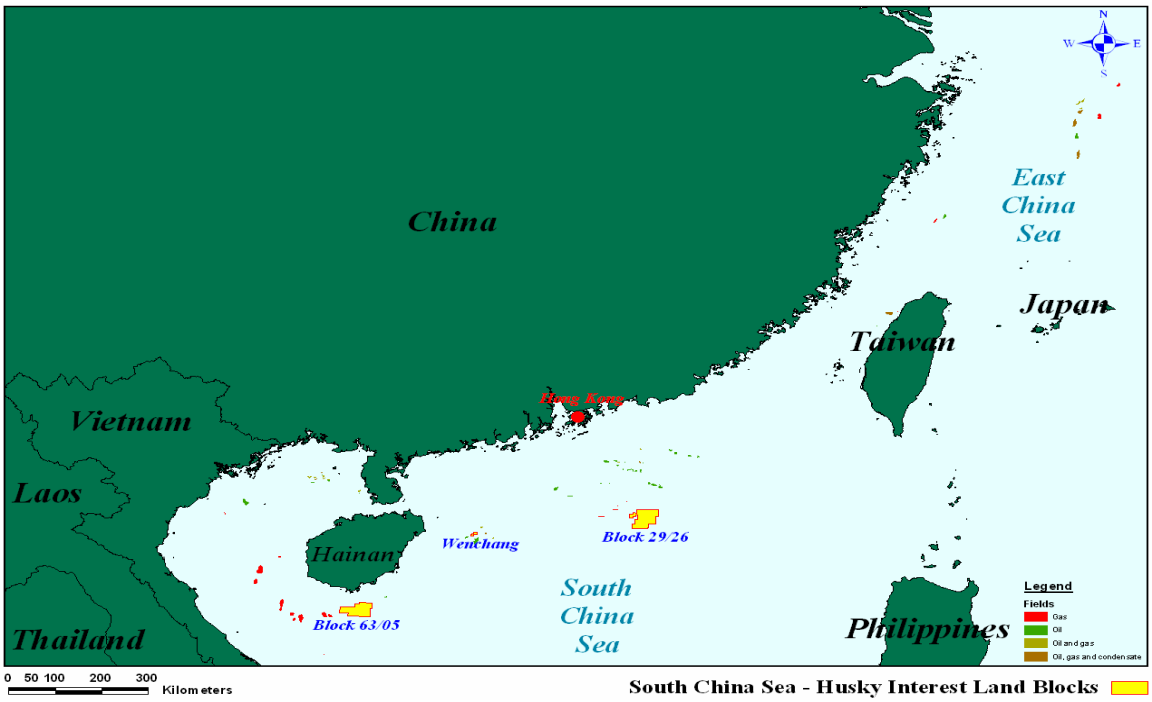
Husky holds three ELs totalling 34,280 sq km offshore the west coast of Disko Island, Greenland. During 2009, Husky acquired 2,200 sq km of 3D seismic over Husky operated licenses 2007/22 (Block 5) and 2007/24 (Block 7) (Husky 87.5% working interest). This program represents the first 3D seismic ever acquired offshore Greenland. A high resolution aero-gravity and magnetic survey covering all three licenses was also completed 2009. Husky is participating in ongoing joint environmental impact studies and ice studies. The Greenland Oil Industry Association ("GOIA") was formed in 2009 and Husky is a founding member. Main objectives of GOIA are to expand the knowledge base to conduct safe and environmentally friendly operations offshore Greenland and to provide a forum for industry communication with stakeholders and authorities. In 2010, Husky completed final processing of the 3-D seismic for Block 7, with final processing of Block 5 data expected to be completed in the first quarter of 2011. Preliminary evaluation of the seismic data has identified several leads. The Company plans to identify potential drilling locations over the course of the first quarter of 2011.



International

Husky's other international exploration and development programs are currently located in South East Asia. In China, the Company has a 40% interest in an offshore oil producing operation at Wenchang and a 100% interest in two exploration blocks in the South China Sea. In Indonesia, the Company currently has a 40% interest in the Madura Strait PSC and a 100% interest in the North Sumbawa II exploration block.

China



South China Sea

Wenchang

The Wenchang field is located in the western Pearl River Mouth Basin, approximately 400 km south of Hong Kong and 100 km east of Hainan Island. Husky holds a 40% working interest in two oil fields, which commenced production in July 2002. The Wenchang 13-1 and 13-2 oil fields are producing from 32 wells in 100 m of water into a floating production, storage and offloading vessel stationed between a fixed platform located in each of the two fields. The blended crude oil from the two fields averages approximately 35° API, similar to the benchmark Minas blend. Husky's working interest gross production averaged 10.7 mbbls/day during 2010.

Block 29/26

Husky executed a PSC with CNOOC for the 29/26 exploration block on October 1, 2004. The block is located in the South China Sea approximately 300 km southeast of Hong Kong and 65 km southeast of the Panyu gas discovery. Water depths range from 700 m to 1,700 m and the block currently covers an area of approximately 551,033 acres (2,230 sq km), following 25% relinquishments at the end of Exploration Phase I in 2007 and Exploration Phase 2 in 2009. CNOOC has the right to participate in the development of any discoveries up to a 51% working interest.

Husky drilled the Liwan 3-1-1 natural gas discovery in 2006. The well was drilled in 1,500 m of water to a total depth of 3,843 m on a large structure with up to 14,826 acres (60 sq km) of closure and encountered 56 m of net natural gas pay on logs over four zones. In August 2006, Husky shot a 98,842 acre (400 sq km) 3D seismic survey over the Liwan 3-1 field and the adjacent structures. In January 2007, the Company signed a 3 year contract with Seadrill Offshore AS for the deep water semi-submersible drilling rig, *West Hercules*. A further 646,180 acres (2,615 sq km) of 3-D seismic data was acquired in 2007 and 2008. The *West Hercules* drilling rig spud the first appraisal well at Liwan 3-1 on November 20, 2008 and successfully completed a three well delineation program in the third quarter of 2009.

During 2009, Husky also drilled four exploration wells on Block 29/26, which resulted in the discovery of a new gas field at Liuhua 34-2, approximately 23 km to the northeast of the Liwan 3-1 field.

In 2010, the Company drilled a new natural gas discovery at Liuhua 29-1, approximately 43 kilometres to the northeast of the Liwan 3-1 field. The well tested natural gas at an equipment restricted rate of 57 mmcf/day. Husky also completed drilling two delineation wells on the 29-1 field.

The Company also drilled exploration wells at the Liwan 3-3, Liwan 5-2, Liuhua 34-2 and Liuhua 34-3 prospects without encountering commercial amount of hydrocarbons.

During 2010, Husky drilled four development wells on the Liwan 3-1 field. The Liwan 3-1-10, Liwan 3-1-9, Liwan 3-1-5 and Liwan 3-1-8 which were cased and will be used as future producing wells as part of the company's nine well development program for the field. The Company also drilled an appraisal well in the eastern part of the Liwan 3-1 field.

In order to accelerate the Liwan 3-1 development a FEED study was initiated in second quarter of 2009 and completed in early 2010. The Original Gas In-place ("OGIP") Report was submitted to the Chinese Government in late December 2009 and was approved in the third quarter of 2010. In late 2010, Husky Oil China Ltd. signed a Heads of Agreement with CNOOC which specifies key principles of the partnership to fund, develop and operate the Liwan 3-1 deep water gas field. This document is a precursor to the Supplemental Development Agreement ("SDA") which will be the definitive agreement governing these issues. Husky expects the plan of development for the Liwan 3-1 field to be submitted in the first quarter of 2011 and is currently tendering all of the deepwater equipment and installation activity. Under the current plan, the Liwan 3-1 and Liuhua 34-2 fields on Block 29/26 will be developed in parallel, with first gas production targeted in late 2013. The plan of development for the Liuhua 29-1 field is targeted for submission in 2012, after appraisal drilling and evaluation work has been completed.

The Liwan 3-1 natural gas field, will use a subsea production system connected to a central shallow water platform by flow lines. The platform will be connected by pipeline to an onshore gas plant with access to the energy markets of Hong Kong and Guangdong province on the China mainland. Husky and development partner, CNOOC, have established a joint marketing group for the sale of Liwan 3-1 natural gas and associated natural gas liquids. The Liuhua 34-2 and Liuhua 29-1 discoveries will be tied into the proposed Liwan 3-1 shallow water infrastructure.

Block 63/05

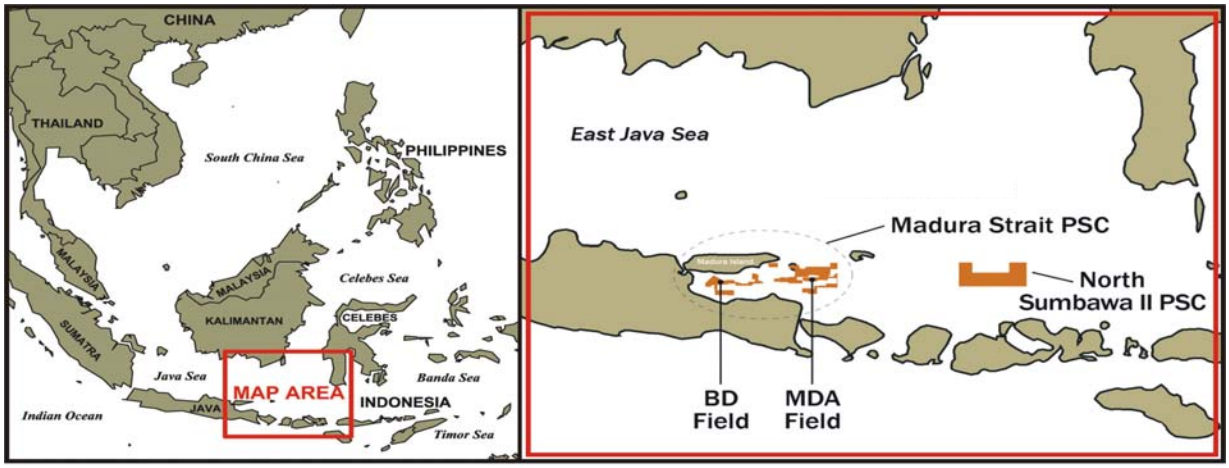
Husky executed a PSC with CNOOC for the 63/05 exploration block on June 25, 2008. The block is located in the South China Sea approximately 50 km south of Hainan Island and covers an area of approximately 439,100 acres (1,777 sq km). The 63/05 block is located in the Qiongdongnan Basin in water depth of less than 120 m. The PSC requires the drilling of a single exploration well in the first exploration phase to a depth of 1,500 m and 300 sq km of 3D seismic, with a minimum work commitment of U.S. $10 million. Processing of new 2-D and 3-D seismic data has been completed and the data is currently being interpreted. A decision will be made in the first quarter of 2011 on the drilling of an exploration well which is planned for later in 2011. CNOOC has the right to participate in the development of any discoveries up to a 51% working interest.

East China Sea

Block 04/35

In 2010, the Company made the decision to relinquish the block at the end of the first exploration term of the PSC. This decision was made following the results of the drilling of the HZ 8-1-1 exploration well which was drilled in 2010 and did not encounter hydrocarbons.

Indonesia



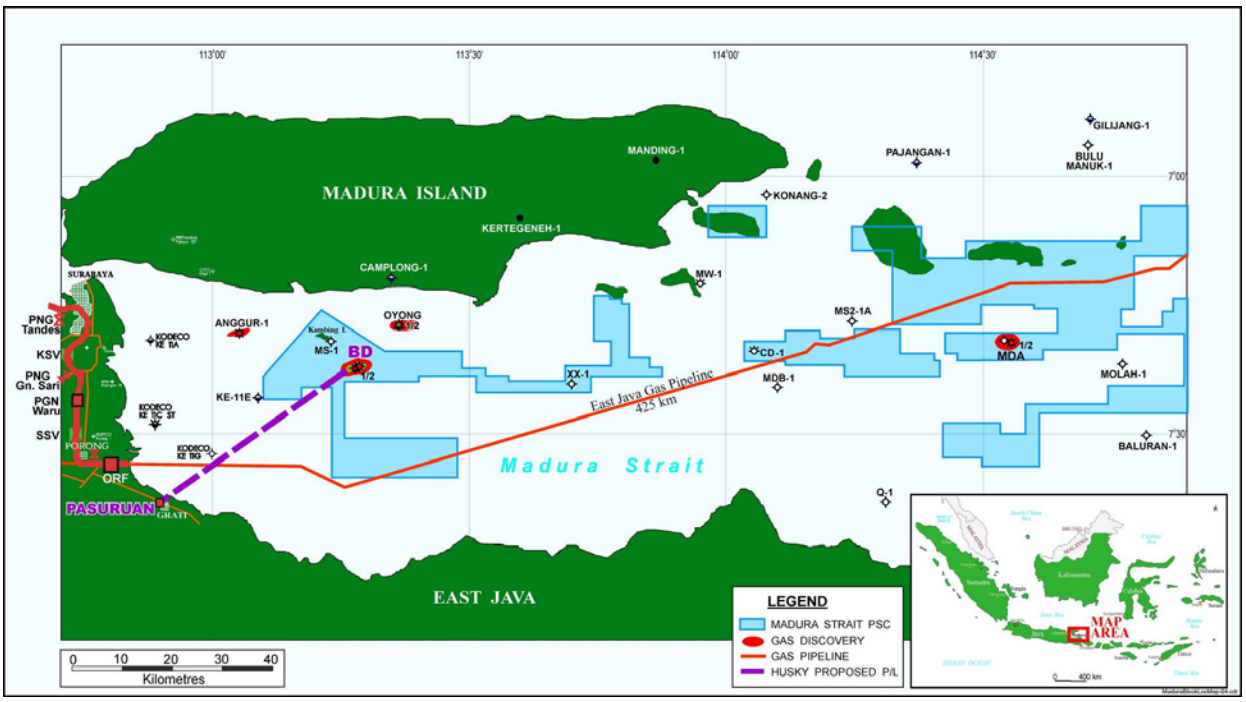
North Sumbawa II, Indonesia

Husky executed a PSC in November 2008 with the Government of Indonesia for the North Sumbawa II block. The block is located in the East Java Basin approximately 300 km east of Madura Strait PSC and covers an area of 1,249,831 acres (5,058 sq km). The PSC requires the acquisition of 2D seismic with a commitment of U.S. $2 million, and the drilling of one exploration well with a commitment of U.S. $10 million within the first three years of contract. Husky satisfied its seismic work commitment by acquiring 1,020 km of 2D seismic in December 2009. Processing of this data is at an advanced stage. Husky will use this data to define an exploration prospect for future drilling, which is currently planned to commence in 2012. Husky holds a 100% interest in the North Sumbawa II block.

Madura Strait, Indonesia

Husky has a 40% interest in approximately 690,412 acres (2,794 sq km) of the Madura Strait block, located offshore East Java, south of Madura Island, Indonesia. The two partners include CNOOC who is the operator and has a 40% working interest and Samudra which has the remaining 20%. There are two discovered natural gas fields on the block. The larger of these is the Madura BD field, which was granted commercial status and had a plan of development approved by the Indonesian state oil company in 1995. 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 at that time and as a result the BD development was deferred. Current market conditions are favourable for the BD development and Husky expects to proceed with plans to supply gas to meet the demand of the East Java region. Husky has gas sales contracts signed with three gas buyers. The updated development plan was approved in 2008 by the Government of Indonesia.

In October 2010, the Government of Indonesia approved an extension of the existing Madura Strait PSC that was originally awarded in 1982. The approval provides a 20-year extension to the existing contract which now runs until 2032. This extension provides the basis for the development of the Madura BD field. The front end engineering was completed in the second quarter of 2010 with the engineering tendering process to begin in early 2011. Production is planned to come on stream in mid 2014.



Shatirah, Libya

The Company has a non-operated interest in a small crude oil production operation in the Shatirah field, onshore Libya. The Company has no personnel currently stationed in Libya.

United States

Columbia River Basin (Washington State – USA)

Husky holds approximately 1.7 million gross acres of undeveloped land in the Columbia River Basin located in the states of Washington and Oregon. This under explored basin is characterized by tertiary sandstones that lie below a layer of volcanic basalt. The potential exists to unlock a large gas resource that is located in an area containing existing natural gas pipelines that transport gas to the states of Washington, Oregon and California. In 2010, Husky participated in a seismic program designed to optimize the seismic acquisition parameters to help penetrate below the basalt cover, with encouraging early results. Evaluation of this new data is continuing and further work on these lands will depend upon the final results of this analysis.

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, Alberta/Saskatchewan. The combined dry crude feedstock requirements of the upgrader and asphalt refinery are equal to approximately 130% of Husky's heavy crude oil production from the Lloydminster area. Therefore, in order to keep all units running at the upgrader and refinery, purchase of third party production is required. 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. NGL 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 gross average daily natural gas production for the years indicated:

	Years ended December 31,		
	2010	**2009**	**2008**
		(mmcf/day)	
Sales to end users			
United States	223	271	348
Canada	164	181	201
	387	452	549
Sales to aggregators	3	5	19
Internal use [(1)]	117	85	28
	507	542	596

Note:

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

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

Delivery Commitments

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

	Fixed Price		Market Price
	Bcf	**$/mmbtu**	**Bcf**
2011	18.7	6.39	2.4
2012	17.6	6.28	1.5
2013	11.5	4.28	1.5
2014	11.5	4.28	1.5
2015	3.8	4.28	1.5

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"), 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 refinery feedstock for the production of premium transportation fuels in Canada and the United States. In addition, the Upgrader recovers the diluent, which is blended with the heavy crude oil prior to pipeline transportation to reduce viscosity and facilitate its movement, and returns it to the field to be reused.

Prior to commissioning of the Upgrader, heavy crude oil was either used as feedstock for asphalt production or sold as blended heavy crude oil for feedstock for specific refineries designed to process or upgrade heavier crude. The Upgrader was commissioned in 1992 with an original design capacity of 46 mbbls/day of synthetic crude oil. Current production is considerably higher than the original design rate capacity as a result of throughput modifications and improved reliability. In 2007, the Upgrader commenced production of off-road diesel for locomotive and other uses. The Upgrader's current rated production capacity is 82 mbbls/day of synthetic crude oil, diluent and off-road diesel. Production at the Upgrader averaged 51 mbbls/day of synthetic crude oil, 10 mbbls/day of diluent and 2 mbbls/day of low sulphur diesel in 2010. In addition, the Upgrader also produced, as by-products of its upgrading operations, approximately 290 lt/day of sulphur and 340 lt/day of petroleum coke during 2010. These products are sold in Canadian and international markets. 2010 production rates were impacted by the major plant turnaround that took place in September and most of October.

Infrastructure

Husky has been involved in the gathering, transporting and storage of heavy crude oil in the Lloydminster area since the early 1960s. Husky's crude oil pipeline systems include more than 2,000 km of pipeline and are capable of transporting up to 710 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 Husky's Upgrader and asphalt refinery in Lloydminster. Blended heavy crude oil from the field and synthetic crude oil from the upgrading operations are transported south to Hardisty, Alberta to a connection with the major export trunk pipelines: Enbridge Pipeline multi-line system, Kinder Morgan Express Pipeline, TransCanada's Keystone Pipeline and the smaller InterPipeline Fund pipeline. The crude oil is transported to eastern and southern markets on these pipelines. Husky's crude oil pipeline systems also have feeder pipeline interconnections with the Cold Lake pipeline, the Echo Pipeline, the Gibsons Hardisty Terminal, the Enbridge Hardisty Caverns, 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,		
(mbbls/day)	**2010**	**2009**	**2008**
Combined pipeline throughput	512	514	507

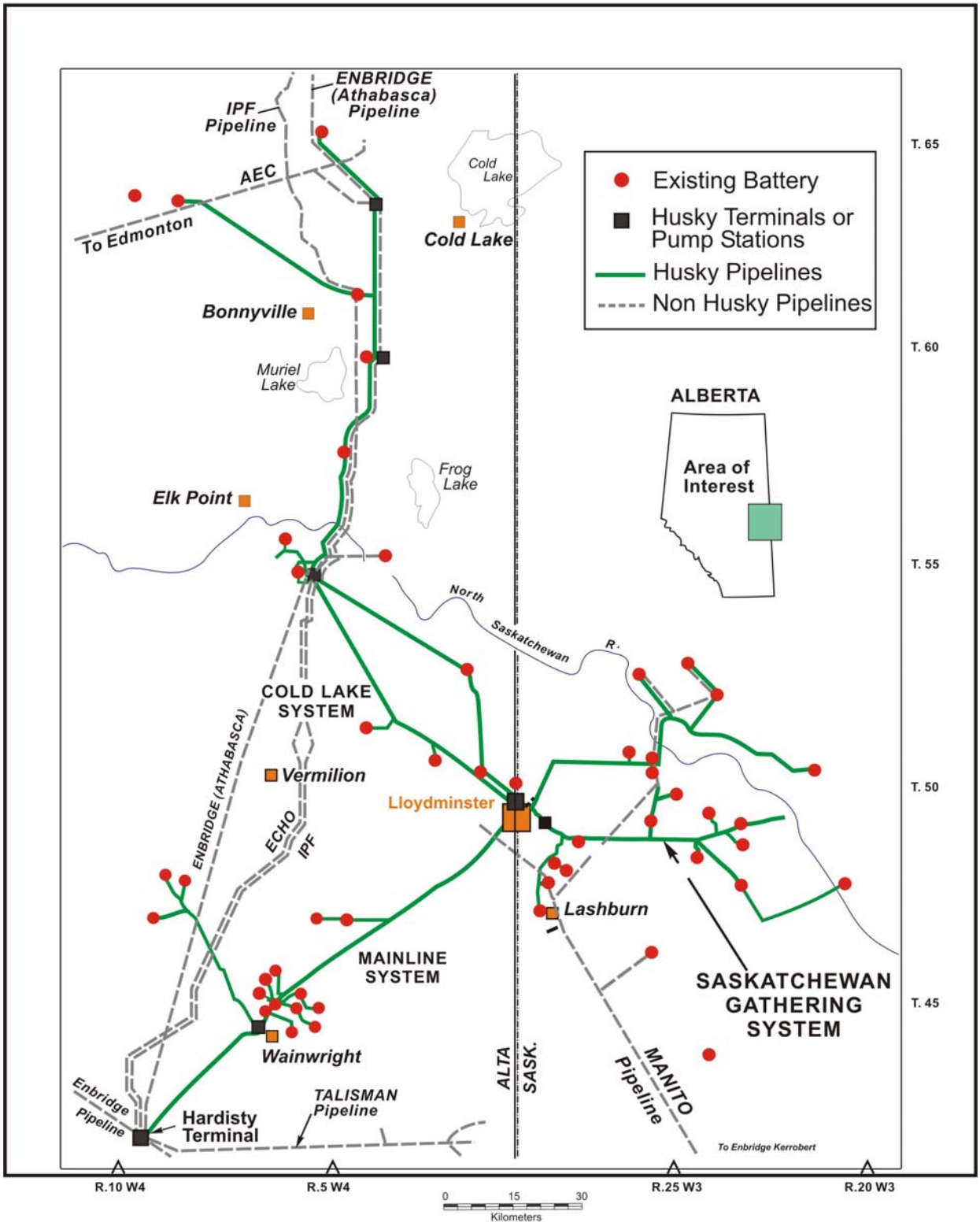
In recent years Husky has incurred a number of expansions on its pipeline system and Hardisty terminal facilities to capitalize on anticipated increases in heavy oil production from the Lloydminster and Cold Lake areas and to service the new incremental take-way capacity from the Keystone pipeline.

Husky considers the expansion and optimization of the pipeline systems in the Lloydminster area necessary to further Husky's development objectives in the area.

Husky's heavy crude oil processing facilities are located throughout the Lloydminster area and are connected to Husky's pipeline system. These facilities process Husky's and other producers' raw heavy crude oil from the field

production by removing sand, water and other impurities to produce clean dry heavy crude oil. There are also third party processing facilities connected to Husky's pipeline. The heavy crude oil is then blended with a diluent to lower both viscosity and density in order to meet pipeline specifications for transportation.

Heavy Oil Pipeline Systems



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In 2010 Husky commenced its pipeline commitment on the Keystone pipeline system which ships Canadian crude oil from Hardisty, Alberta to Patoka, Illinois. This commitment was part of a corporate initiative, agreed in 2006 to expand the market for Husky crude oil into the Midwest. It was further supported through the acquisition of the Lima refinery in 2007, which now enables Husky's Canadian synthetic crude oil production (along with additional third party purchases) to be processed at the refinery.

Due to Husky's ongoing Keystone commitment, Lima refinery now has the option, depending on the economics, to access a significant amount Canadian synthetic crude oil as part of its crude feedstock requirements.

Keystone has also enabled Husky to sell heavy equity crude supply on the Gulf Coast, through interconnecting pipeline systems. This provides the benefits of diversifying Husky's commodity markets and improving our production netback pricing.

During the Enbridge pipeline outages in late 2010, the Keystone pipeline was a major factor in alleviating the shut-in pressures felt by all Canadian producers and ensured Husky avoided any production shut-in and maintained market access for our crude sales.

Cogeneration

Husky holds a 50% interest in a 215 MW natural gas fired cogeneration facility at the site of the Lloydminster Upgrader. TransAlta Cogeneration, L.P. ("TACLP") is the Husky's joint venture partner for the cogeneration facility. This cogeneration 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. In February 2011, Husky and TACLP agreed to sell the cogeneration facility to an indirect wholly owned subsidiary of Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited. Completion of the transaction is subject to consent from Saskatchewan Power Corporation as well as regulatory approval. The transaction is expected to be completed by April 2011.

The Company also holds a 50% interest in a 90 MW natural gas fired cogeneration facility adjacent to Husky's Rainbow Lake processing plant. The cogeneration plant produces electricity for the Alberta Power Pool and thermal energy (steam) for the Rainbow Lake processing plant. It provides power directly to the Alberta Power Pool under an agreement with the Alberta Electric System Operator 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. ATCO Power is the operator of the facility, and hands-on operator of the Rainbow #5 electricity generator. Husky contract-operates the Rainbow #4 electricity generator, the Once-Through Steam Generator ("OTSG") and the Water Treatment Plant. All of this equipment constitutes part of the cogeneration facility.

Natural Gas Storage Facilities

Husky has been operating a natural gas storage facility at Hussar, Alberta since April 2000. Husky also operates and has a 50% interest in a natural gas storage facility at East Cantuar near Swift Creek, Saskatchewan. Husky also contracts additional natural gas storage under long-term arrangements. At December 31, 2010, Husky managed a total natural gas storage capacity of approximately 50 bcf. The Company 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. The Company also markets petroleum coke, a by-product from the Lloydminster Upgrader.

Husky supplies feedstock to its Upgrader and asphalt refinery from its own and third party heavy oil production sourced from the Lloydminster and Cold Lake areas. The Company also sells blended heavy crude oil directly to refiners based in the United States and Canada. Husky's extensive infrastructure in the Lloydminster area supports its heavy crude oil refining and marketing operations.

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

Husky markets natural gas sourced from its own production and third party production. The Company is currently committed to gas sales contracts with third parties, which in aggregate do not exceed amounts forecast to be deliverable from Husky reserves. Husky's contracts are with customers located in eastern Canada/northeastern United States (24.6%), midwestern United States (24.9%), Western Canada (48.2%) and northwestern United States (2.3%). The natural gas sales contracted are primarily at market prices (90%). At December 31, 2010, Husky's long-term fixed price natural gas sales contracts totalled 63.1 bcf over five years deliverable at the rate of 30% in 2011, 28% in 2012, 18% in 2013, 18% in 2014 and 6% in 2015. Husky has acquired rights to firm pipeline capacity to transport the natural gas to most of these markets. The Company manages and trades natural gas in conjunction with Husky owned and operated natural gas storage facilities.

Husky has developed its commodity marketing operations to include the acquisition of third party volumes in order to increase volumes and enhance the value of its midstream assets. The Company plans to expand its marketing operations by continuing to increase marketing activities. The Company believes that this increase will generate synergies with the marketing of its own production volumes and the optimization of its assets. At December 31, 2010, Husky estimated commitments of approximately $199 million in natural gas purchases, 93% of which is to be purchased in 2011. At December 31, 2010, the Company did not have any long-term commitments to purchase crude oil. Husky's purchases of crude oil primarily involve 30 day evergreen arrangements.

Downstream Operations

Canada

Overview

Husky's Canadian refined products operations include refining of light crude oil, manufacturing of fuel and fuel grade ethanol, manufacturing of asphalt products from heavy crude oil, acquisition by purchase and exchange of refined petroleum products. Husky's retail distribution network includes the wholesale, commercial and retail marketing of refined petroleum products and provides a platform for substantial non-fuel related convenience product businesses.

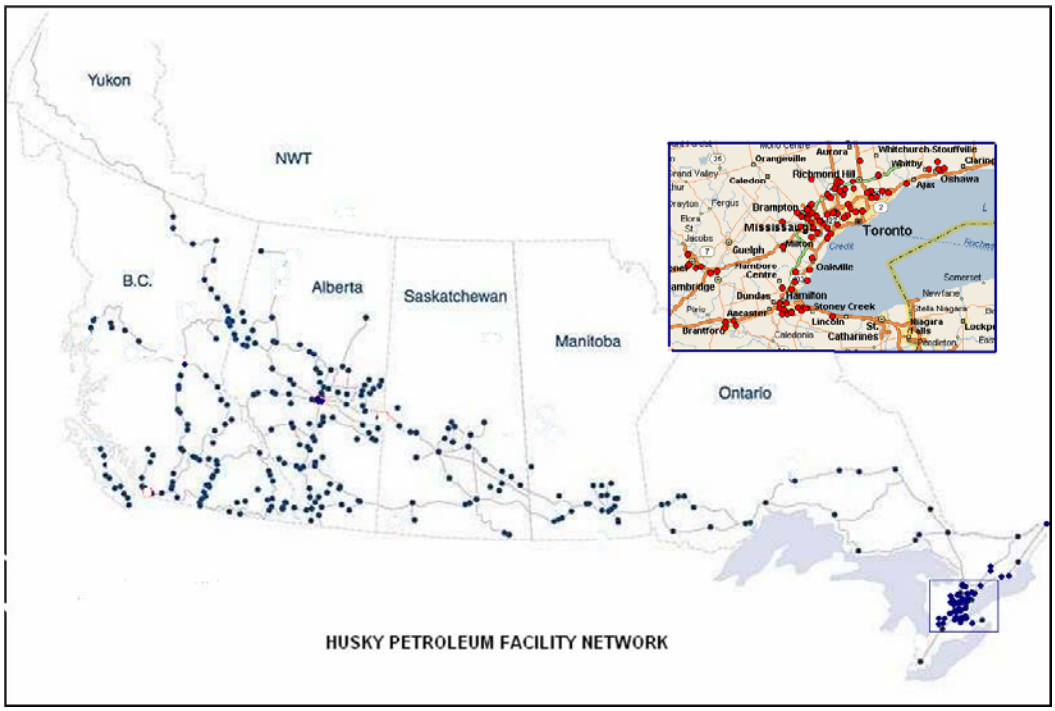
Light oil refined products are produced at the Husky refinery at Prince George, British Columbia and are also acquired from third party refiners and marketed through Husky and Mohawk branded retail and commercial petroleum outlets and through direct marketing to third party dealers and end users. Asphalt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

Branded Petroleum Product Outlets and Commercial Distribution

As of December 31, 2010 there were 555 independently operated Husky- and Mohawk-branded petroleum product outlets. These petroleum product outlets include travel centres, convenience stores, cardlock operations 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 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 electronically processes transactions and provides detailed billing, sales tax and other information. A variety of full- and self-serve retail locations under the Husky and Mohawk brand names serve urban and rural markets, while Husky and Mohawk bulk distributors offer direct sales to commercial and farm markets in Western Canada.

Husky's strategy is to improve earnings by maximizing the operational efficiencies of its retail and commercial network. Plans include assessing and rationalizing low-performing sites, changes to operating and marketing programs and selectively filling in the network through new independent outlets that will grow per-site throughput and earnings.

In December 2009, Husky completed an agreement to purchase 98 retail stations in Southern Ontario from Suncor. At the end of 2010, Husky had completed rebranding the sites to the Husky brand. The addition of these sites resulted in a 23% increase in Husky's retail sites, a 35% increase in Husky's corporately controlled retail sites, Ontario volume market share growth of 4% (3.5% to 7.7%), an additional 476 million litres/year of gasoline and diesel sales and 8,200 bpd propriety retail demand exposure within 400 miles of the Lima Refinery.



Independent retailers or agents operate all Husky- and Mohawk-branded petroleum product outlets. Retail outlets feature varying services such as convenience stores, service bays, 24-hour service, car washes, Husky House full-service, family-style restaurants, proprietary and co-branded quick-serve restaurants and bank machines. In addition to ethanol-blended gasoline branded as *Mother Nature's Fuel*, Husky offers additive-enhanced *DieselMax* and propane services 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 Husky's sponsorship of Alpine Canada, the Western Hockey League and various university athletics, 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, 2010:

	British Columbia & Yukon	Alberta	Sask.	Manitoba	Ontario	2010 Total	2009 Total
Retail Owned Outlets							
Travel Centres	11	9	4	2	14	40	40
Full Serve	5	11	1	3	18	38	25
Full/Self Serve	19	11	5	11	1	47	50
Self Serve	22	34	3	—	44	103	52
Bulk Distributor	3	7	2	1	—	13	13
Other Service Facilities Distributor	3	5	—	—	1	9	10
	63	77	15	17	78	250	190
Leased							
Travel Centres	—	—	—	—	—	—	1
Full Serve	3	4	3	5	5	20	17
Full/Self Serve	5	15	2	3	1	26	26
Self Serve	34	32	—	—	30	96	67
Bulk Distributor	—	—	1	—	1	2	4
Other Service Facilities Distributor	2	2	—	3	2	9	11
	44	53	6	11	39	153	126
Independent Retailers							
Travel Centres	1	3	—	—	4	8	8
Full Serve	15	3	7	7	5	37	38
Full/Self Serve	12	9	—	1	—	22	24
Self Serve	23	38	8	1	2	72	76
Bulk Distributor	3	4	2	—	—	9	7
Other Service Facilities Distributor	1	2	—	—	1	4	4
	55	59	17	9	12	152	157
Total							
Travel Centres	12	12	4	2	18	48	49
Full Serve	23	18	11	15	28	95	80
Full/Self Serve	36	35	7	15	2	95	100
Self Serve	79	104	11	1	76	271	195
Bulk Distributor	6	11	5	1	1	24	24
Other Service Facilities Distributor	6	9	—	3	4	22	25
	162	189	38	37	129	555	473
Cardlocks (1)	27	30	6	6	23	92	94
Convenience Stores (1)	54	51	16	9	71	201	276
Restaurants	12	13	4	2	17	48	48

Note:

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

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

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

	Years ended December 31,		
	2010	**2009**	**2008**
		(mbbls/day)	
Gasoline	24.9	25.3	25.0
Diesel fuel	25.7	21.8	23.8
Liquefied petroleum gas	0.7	0.8	0.9
	51.3	47.9	49.7

Supply

Prince George Refinery

The Prince George refinery production is equal to approximately 20% of Husky's total refined product supply requirements and is the source of its lowest cost refined products. The refinery produces all grades of unleaded gasoline, seasonal ultra low sulphur diesel fuels, mixed propane and butane stream and heavy oil products.

Lloydminster Asphalt Refinery

Husky's Lloydminster refinery processes heavy crude into asphalt products used in road construction and maintenance and industrial asphalt products. The refinery has a throughput capacity of 29 mbbls/day of heavy crude oil. The refinery also produces straight run gasoline, bulk distillates and residuals. The straight run gasoline stream is removed and re-circulated into the heavy oil pipeline network as pipeline diluent and the distillate stream is used by the Upgrader to make low sulphur diesel. The bulk distillates are hydrogen deficient and are transferred directly to the Upgrader and then treated for blending into the Husky Synthetic Blend stream. Residuals are a blend of medium and light distillate and gas oil streams, which are sold directly to customers typically as drilling and well fracturing fluids or used in asphalt cutbacks and emulsions.

Ethanol Manufacturing

In September 2006, Husky commissioned an ethanol facility in Lloydminster, Saskatchewan. This plant has an annual nameplate capacity of 130 million litres. In December 2007, the Minnedosa, Manitoba ethanol plant was commissioned also with an annual nameplate capacity of 130 million litres, but the plant is operating above that capacity.

Husky's ethanol production supports its "*Mother Nature's Fuel*" ethanol-blended gasoline marketing program. When added to gasoline, ethanol promotes more complete fuel combustion, prevents fuel line freezing and reduces carbon monoxide emissions, ozone precursors and net emissions of greenhouse gases. Environment Canada has designated ethanol-blended gasoline as an "Environmental Choice" product.

Husky continued to position its Refined Products business segment as the leader in ethanol blended fuels in Western Canada.

Other Supply Arrangements

In addition to the refined petroleum products supplied by the Prince George refinery of 2.6 mbbls/day and 1.8 mbbls/day supplied by the Husky Lloydminster Upgrader, Husky has rack based pricing purchase agreements for refined products with all major Canadian refiners. During 2010, Husky purchased approximately 34.7 mbbls/day of refined petroleum products from refiners and acquired approximately 8.1 mbbls/day of refined petroleum products pursuant to exchange agreements with third party refiners. During 2010, Husky also delivered an average of 2.1 mbbls/day of crude oil to be refined under a processing agreement by another refiner, yielding approximately 1.9 mbbls/day of refined petroleum products.

Asphalt Product

Husky produces asphalt and residual products at its 29 mbbls/day asphalt refinery in Lloydminster, Alberta and markets these products to customers across Western Canada, Ontario, Quebec and the United States.

Husky has 38% of the market for asphalt sold in Western Canada. Husky's Pounder Emulsions division has a 55% market share in Western Canada for road application emulsion products. Additional non-asphalt based road maintenance products are also marketed and distributed through Pounder. The Company's sales to the United States and Eastern Canada accounted for 50% of asphalt sales in 2010. Exported asphalt products are shipped as far as Texas, Florida and Quebec. Husky sells in excess of 5 mmbbls of asphalt cements per year.

Husky's asphalt distribution network consists of five emulsion plant/asphalt terminals located at Kamloops, British Columbia; Edmonton and Lethbridge, Alberta; Yorkton, Saskatchewan; and Winnipeg, Manitoba and three emulsion plants located at Watson Lake, Yukon (closed); Lloydminster and Saskatoon, Saskatchewan. Husky also terminals asphalt at its Prince George Refinery and uses an independently operated terminal at Langley, British Columbia.

All of Husky's asphalt requirements are supplied by the Lloydminster, Alberta asphalt refinery. The refinery had an original design rate throughput capacity of 25 mbbls/day. Debottleneck modifications have allowed Husky to increase throughput capacity to 29 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 produced heavy crude oil.

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

	Years ended December 31,		
	2010	**2009**	**2008**
		(mbbls/day)	
Asphalt	14.9	13.6	13.6
Residual and other	9.2	9.0	10.4
	24.1	22.6	24.0

Refinery throughput averaged 27.8 mbbls/day of blended heavy crude oil feedstock during 2010. Due to the seasonal demand for asphalt products, most asphalt refineries typically operate at full capacity only during the normal paving season in Canada and the northern United States. Husky has implemented various plans to increase refinery throughput during the other months of the year, such as increasing storage capacity and developing U.S. markets for asphalt products. This allows Husky to run at or near full capacity year round.

Husky's strategy with respect to its asphalt marketing business is to expand retail sales by developing retail opportunities, investigating alternate sources of asphalt, maintaining Husky's market position given changes occurring in the market, optimizing the value of the existing business, adjusting the products and product lines to manage resources, and implementing communication mechanisms and supporting systems to enhance organizational effectiveness and achievement of results.

In 2011, Husky will direct its efforts to increasing storage at its Kamloops facility, expanding sales for road stabilization, preservation and recycling, looking at increasing residual sales relative to diluents and bulk distillates to enhance margins, sales of higher quality products with larger margins, implementing safety and reliability improvements and development of new products and improving existing products.

United States

Refining and Marketing

Lima Ohio Refinery

Acquisition of the Lima Refining Company closed on July 3, 2007. The Lima Refinery has an atmospheric crude throughput capacity of 160 mbbls per stream day. The refinery is located in Ohio between Toledo and Dayton and currently processes both light sweet crude oil feedstock sourced from the United States and Africa and since 2010, with the commissioning of the Keystone Pipeline system, Canadian synthetic crudes, including Husky Synthetic Blend ("HSB") produced by the Husky Upgrader. The refinery produces gasoline, gasoline blend stocks, diesel, jet fuel, petrochemical feedstock and other by-products. The feedstock is received via the Mid-Valley and Marathon pipelines and the refined products are transported via the Buckeye and Inland pipeline systems and by

rail car to primary markets in Ohio, Illinois, Indiana and southern Michigan.

During 2010 crude oil feedstock throughput averaged 137 mbbls/day. Production of gasoline averaged 72 mbbls/day, middle distillates averaged 50 mbbls/day and other fuel and feedstock averaged 14 mbbls/day.

Toledo Ohio Refinery

On March 31, 2008, Husky and BP completed a transaction that created an integrated North American oil sands business. The business comprises a 50/50 partnership to develop the Sunrise Energy Project, operated by Husky, and a 50/50 limited liability company for the Toledo Ohio Refinery, operated by BP.

The Toledo Refinery has an atmospheric crude throughput capacity of 160 mbbls per stream day (nameplate). Products include low sulphur gasoline, ultra low sulphur diesel, aviation fuels, propane, kerosene and asphalt. It is located in one of the highest energy consumption regions in the United States.

Husky and BP plan to expand the refinery's bitumen processing capacity to align with the first two 60 mbbls/day phases of the Sunrise SAGD development. BP currently markets 100% of the refinery's output; however, upon commencement of bitumen deliveries from Sunrise, Husky will have the right to market its own share of the refined products.

In 2010, Husky and BP announced the sanction of the Continuous Catalyst Reformer Project at the Toledo, Ohio Refinery. This project will improve the efficiency and competitiveness of the refinery by reducing energy consumption and lowering operating costs with the replacement of two naphtha reformers and one hydrogen plant with a 42,000 bbls/day continuous catalyst regeneration reformer system plant. Project construction formally commenced in August 2010. Anticipated project completion is the fourth quarter of 2012.

During the twelve months ended December 31, 2010, crude oil feedstock throughput averaged 64 mbbls/day (Husky's share). Production of gasoline averaged 40 mbbls/day, middle distillates averaged 18 mbbls/day and other fuel and feedstock averaged 6 mbbls/day.

Human Resources

The number of permanent employees was as follows:

	December 31,		
	2010	**2009**	**2008**
	4,380	4,272	4,298

DIVIDENDS

The following table shows the aggregate amount of the dividends per common share of the Company paid in respect of its last three years ended December 31:

	2010	**2009**	**2008**
Dividends per common share	$ 1.20	$ 1.20	$ 1.70

Dividend Policy and Restrictions

The Board of Directors of Husky has established a dividend policy that pays quarterly dividends. The dividend was reviewed in July 2006 and was increased to $0.25 ($1.00 annually) per common share and again in October 2007 when it was increased to $0.33 ($1.32 annually). The dividend was again reviewed in April 2008 and was increased to $0.40 ($1.60 annually) per common share and again in July 2008 when it increased to $0.50 ($2.00 annually). In February 2009, the dividend was reviewed and was decreased to $0.30 ($1.20 annually) per common share. The Board declared special dividends in the amount of $0.50 per common share in July 2003 and $0.27 per common share in November 2004. In October 2005, the Board declared a special dividend of $0.50 per common share. In February 2007, the Board declared a special dividend of $0.25 per common share.

In February 2011, Husky's shareholders approved amendments to the common share terms to provide the shareholders with the ability to receive dividends in common shares or cash. Quarterly dividends would be declared in an amount expressed in dollars per common share and would be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares would be calculated by dividing the total value by the total volume of common shares traded over the 5 trading day period immediately

prior to the payment date of the dividend on the common shares. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash.

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 receive notice of and to attend all meetings of shareholders, except meetings at which only holders of a specified class or series of shares are entitled to vote, and to one vote per share held. Holders of common shares are also entitled to receive dividends as declared by the Board of Directors on the common shares payable in whole or in part as a stock dividend in fully paid and non-assessable common shares or by the payment of cash and to receive the remaining property of Husky upon dissolution in equal rank with the holders of all other common shares. See "Dividend Policy and Restrictions".

If the directors of Husky declare a dividend on the common shares payable in whole or in part as a stock dividend, shareholders that will accept a payment of future stock dividends declared by the Board of Directors in the form of common shares are required to complete and deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend. The Stock Dividend Confirmation Notice permits shareholders to confirm that they will accept common shares as payment of the dividend on all or a stated number of their common shares. A Stock Dividend Confirmation Notice will remain in effect for all stock dividends on the common shares to which it relates and which are held by the shareholder unless the shareholder delivers a revocation notice to Husky's transfer agent, in which case the Stock Dividend Confirmation Notice will not be effective for any dividends having a declaration date that it is more than five business days following receipt of the revocation notice by Husky's transfer agent.

In the event of a shareholder failing to deliver a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend, or delivering a Stock Dividend Confirmation Notice confirming that the holder of common shares accepts the common shares as payment of the dividend on some but not all of the holder's common shares, the dividend on common shares for which no Stock Dividend Confirmation Notice was delivered, or the dividend on those of the holder's common shares in respect of which the holder did not deliver a Stock Dividend Confirmation Notice, will be paid in cash.

Preferred Shares

Husky is authorized to issue an unlimited number of preferred shares. The preferred shares as a class have attached thereto the rights, privileges, restrictions and conditions set forth below.

The preferred shares may from time to time be issued in one or more series, and the Board of Directors may fix from time to time before such issue the number of preferred shares which is to comprise each series and the designation, rights, privileges, restrictions and conditions attaching to each series of preferred shares including, without limiting the generality of the foregoing, any voting rights, the rate or amount of dividends or the method of calculating dividends, the dates of payment thereof, the terms and conditions of redemption, purchase and conversion if any, and any sinking fund or other provision.

The preferred shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding up of Husky, whether voluntary or involuntary, or any other return of capital or distribution of assets of Husky amongst its shareholders for the purpose of winding up its affairs, be entitled to preference over the common shares of Husky and over any other shares of Husky ranking by their terms junior to the preferred shares of that series. The preferred shares of any series may also be given such other preferences over the common shares of Husky and any other such preferred shares.

If any cumulative dividends or amounts payable on the return of capital in respect of a series of preferred shares are not paid in full, all series of preferred shares shall participate ratably in respect of accumulated dividends and return of capital.

Liquidity Summary

The following information relating to Husky's credit ratings is provided as it relates to Husky's financing costs, liquidity and operations. Specifically, credit ratings affect Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Husky to engage in certain collateralized business activities on a cost effective basis depends on Husky's credit ratings. A reduction in the current rating on Husky's debt by its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in Husky's ratings outlook could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect Husky's ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require Husky to post additional collateral under certain of its contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Under Review	December 15, 2010	March 5, 2010
Senior Unsecured Debt	Baa2	March 5, 2010	April 25, 2001
Standard and Poor's:			
Outlook	Stable	November 30, 2010	July 27, 2006
Senior Unsecured Debt	BBB+	November 30, 2010	July 27, 2006
Dominion Bond Rating Service:			
Trend	Stable	November 26, 2009	March 31, 2008
Senior Unsecured Debt	A (low)	November 26, 2009	March 31, 2008

Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer 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.

On December 15, 2010 Moody's placed Husky Energy Inc.'s Baa2 senior unsecured rating and Ba1 junior subordinated rating on review for a possible downgrade. At this time the outcome of the review is not yet determined.

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 appear 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 A category are considered to be of satisfactory 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.

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, 2010:

	High	Low	Volume (000's)
January	30.88	26.46	21,328
February	27.84	26.82	29,013
March	29.22	28.31	30,003
April	30.70	28.61	20,473
May	29.06	25.37	29,108
June	27.30	25.13	22,809
July	27.10	24.87	17,517
August	26.06	24.21	25,287
September	26.14	24.95	21,938
October	25.81	24.97	21,892
November	26.37	24.44	31,382
December	26.58	24.41	23,607

DIRECTORS AND OFFICERS

The following are the names and residences of the directors and officers of Husky as of the date of this Annual Information Form, their positions and offices with Husky and their principal occupations during the past five years. Each director will hold office until the Company's next annual general meeting, or until his or her successor is appointed or elected.

Directors

Name & Residence	Officer or Position	Principal Occupation During Past 5 Years
Li, Victor T.K. Hong Kong	Director and Co-Chair Director of Husky Energy Inc. since 2000	Mr Li is Managing Director and Deputy Chairman of Cheung Kong (Holdings) Limited (a public investment holding and project management company). Mr. Li is also Deputy Chairman and Executive Director of Hutchison Whampoa Limited (an investment holding company); Chairman and Executive Director of Cheung Kong Infrastructure Holdings Limited (an infrastructure company) and of CK Life Sciences Int'l., (Holdings) Inc. (a biotechnology company); Executive Director of Power Assets Holding Limited (formerly Hongkong Electric Holdings Limited) (a holding company); and a Non-executive Director of The Hongkong and Shanghai Banking Corporation Limited. Mr. Li is a member of the Standing Committee of the 11th 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 Commission on Strategic Development and the Council for Sustainable Development of the Hong Kong Special Administrative Region, and Vice Chairman of the Hong Kong General Chamber of Commerce and was a member of the Greater Pearl River Delta Business Council for the Hong Kong Special Administrative Region. Mr. Li is also the Honorary Consul of Barbados in Hong Kong. Mr. Li holds a Bachelor of Science degree in Civil Engineering, a Master of Science degree in Structural Engineering and an honorary degree, Doctor of Laws, honoris causa (LL.D).
Fok, Canning K.N. Hong Kong	Director, Co-Chair and Chair of the Compensation Committee Director of Husky Energy Inc. since 2000	Mr. Fok is Group Managing Director and Executive Director of Hutchison Whampoa Limited. Mr. Fok is also a director and Chairman of Hutchison Harbour Ring Limited (an investment holding company), Hutchison Telecommunications International Limited (a telecommunications company), Hutchison Telecommunications Hong Kong Holdings

		Limited (a telecommunications company), Hutchison Telecommunications (Australia) Limited (a telecommunications company), and Power Assets Holdings Limited (formerly Hongkong Electric Holdings Limited (a holding company), a director and Deputy Chairman of Cheung Kong Infrastructure Holdings Limited, and a director of Cheung Kong (Holdings) Limited. Mr. Fok was also a director of Hanny Holdings Limited from 2002-2006, Panvas Gas Holdings Limited from 2002 to 2006, Partner Communications Company from 1998 to 2009 and Chairman and a director of Hutchison Telecommunications International Limited from 2005 to 2010. Mr. Fok holds a Bachelor of Arts degree and a Diploma in Financial Management, and is a member of the Australian Institute of Chartered Accountants.
Bradley, Stephen Hong Kong	Director Director of Husky Energy Inc. since July 2010	Mr. Bradley is a director of Broadlea Group Ltd., Senior Representative (China), Grosvenor Ltd., Vice Chairman, ICAP (Asia Pacific) and a director of Swire Properties Ltd. and Special Advisor to the Chief Executive Officer of Rio Tinto Ltd. Mr. Bradley entered the Foreign and Commonwealth Office in 1981 and served in various capacities including Director of Trade & Investment Promotions (Paris) from 1999 to 2002; Minister, DHM & Consul-General (Beijing) from 2002 to 2003 and HM Consul-General (Hong Kong) from 2003 to 2008. Mr. Bradley retired from the HM Diplomatic Service in 2009.
Fullerton, R. Donald Ontario, Canada	Director and Chair of the Audit Committee Director of Husky Energy Inc. since 2003	Mr. Fullerton is a director of the Li Ka Shing (Canada) Foundation and 3 Italia S.p.A. During his career Mr. Fullerton has served as a director of a number of public and private companies both domestic and international including Asia Satellite Telecommunications Holdings Limited from 1996 to 2006; George Weston Limited (a holding company) from 1991 to 2005; Partner Communications Company Ltd. from 2003 to 2005; and CIBC from 1974 to 2004. Mr. Fullerton holds a Bachelor of Arts degree.
Ghosh, Asim Alberta, Canada	Director, President and Chief Executive Officer Director of Husky Energy Inc. since May 2009	Mr. Ghosh was appointed the President and Chief Executive Officer of Husky Energy Inc. on June 1, 2010. Prior thereto Mr. Ghosh was the Managing Director and Chief Executive Officer of Vodafone Essar Limited (a

		telecommunications company) until March 2009. Mr. Ghosh began his career with Procter & Gamble in Canada in 1971 and subsequently worked with Rothmans International in what was then its Carling O'Keefe subsidiary from 1980 to 1988, his last position being Senior Vice President of the brewery operations. In 1989, Mr. Ghosh moved to India as the Chief Executive Officer of the Pepsi Foods (Frito Lay) start up in India. From 1991 to 1998 he held senior executive positions and then the position of Chief Executive Officer of the A S Watson Industries subsidiary (a manufacturer of consumer goods) of Hutchison Whampoa Limited. In August 1998, he became Managing Director and Chief Executive Officer of the company that would become Vodafone Essar Limited. Mr. Ghosh obtained an undergraduate degree in Electrical Engineering from the Indian Institute of Technology in 1969 and an MBA from the Wharton School, University of Pennsylvania in 1971. Mr. Ghosh was Chairman of the Cellular Operators Association of India and the National Telecom Committee of the Confederation of Indian Industries. He is an independent director of Kotak Mahindra Bank Limited, a listed Bank in India, and was on the Board of Directors of Vodafone Essar Limited until February 2010.
Glynn, Martin J.G. British Columbia, Canada	Director, Chair of the Corporate Governance Committee and a Member of the Compensation Committee Director of Husky Energy Inc. since 2000	Mr. Glynn is a director of Hathor Exploration Limited (a mining exploration company), VinaCapital Vietnam Opportunity Fund Limited (an investment fund), MF Global Holdings Ltd. (a futures and options broker), Sun Life Financial Inc. and Sun Life Assurance Company of Canada. Mr. Glynn was a director from 2000 to 2006 and President and Chief Executive Officer of HSBC Bank USA N.A. from 2003 until his retirement in 2006. Mr. Glynn was a director of HSBC Bank Canada from 1999 to 2006 and President and Chief Executive Officer from 1999 to 2003. Mr. Glynn holds a Bachelor of Arts, Honours degree and a Masters degree in Business Administration.

Koh, Poh Chan Hong Kong	Director Director of Husky Energy Inc. since 2000	Ms. Koh is Finance Director, Harbour Plaza Hotel Management (International) Ltd. (a hotel management company). Ms. Koh is qualified as a Fellow Member (FCA) of the Institute of Chartered Accountants in England and Wales and is an Associate of the Canadian Institute of Chartered Accountants and the Chartered Institute of Taxation in the U.K.
Kwok, Eva L. British Columbia, Canada	Director, Member of the Compensation Committee and the Corporate Governance Committee Director of Husky Energy Inc. since 2000	Mrs. Kwok is Chairman, a director and Chief Executive Officer of Amara Holdings Inc. (a private investment holding company). Mrs. Kwok is also a director of CK Life Sciences Int'l., (Holdings) Inc. and Cheung Kong Infrastructure Holdings Limited. Mrs. Kwok is also a director of the Li Ka Shing (Canada) Foundation. Mrs. Kwok was a Director of Shoppers Drug Mart Corporation from 2004 to 2006 and of the Bank of Montreal Group of Companies until March, 2009. Mrs. Kwok holds a Masters degree in Science.
Kwok, Stanley T.L. British Columbia, Canada	Director and Chair of the Health, Safety and Environment Committee Director of Husky Energy Inc. since 2000	Mr. Kwok is a director and President of Stanley Kwok Consultants (an architecture, planning and development company). Mr. Kwok is also a director and President of Amara Holding Inc. and a director of Cheung Kong (Holdings) Limited. Mr. Kwok holds a Bachelor of Science degree (Architecture) and an A.A. Diploma from the Architectural Association School of Architecture in London (England).
Ma, Frederick S. H. Hong Kong	Director and Member of the Audit Committee and the Health, Safety and Environment Committee Director of Husky Energy Inc. since July 2010	Mr. Ma has held senior management positions in international financial institutions and Hong Kong publicly listed companies in his career. In July 2002, he joined the Government of the Hong Kong Special Administrative Region as the Secretary for Financial Services and the Treasury. He assumed the post of Secretary for Commerce and Economic Development in July 2007. In October 2008, he was appointed an Honorary Professor of the School of Economics and Finance at the University of Hong Kong. In July 2009, he was appointed as a Member of the International Advisory Council of China Investment Corporation. He is the Chairman and Non-Executive Director of China Strategic

		Holdings Limited, a Hong Kong listed company. Mr. Ma graduated from the University of Hong Kong with a Bachelor of Arts (Honours) degree in economics and history.
Magnus, George C. Hong Kong	Director and Member of the Audit Committee Director of Husky Energy Inc. since July 2010	Mr. Magnus acted as an Executive Director of Cheung Kong (Holdings) Limited from 1980 and Deputy Chairman of Cheung Kong (Holdings) Limited from 1985 until his retirement from these positions in October 2005. He has been a non-executive Director of Cheung Kong (Holdings) Limited since November 2005. He is also a Non-executive Director of Hutchison Whampoa Limited, Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited (formerly Hongkong Electric Holdings Limited), all listed companies. Mr. Magnus holds a Master's degree in Economics.
Russel, Colin S. Gloucestershire, United Kingdom	Director, Member of the Audit Committee and the Health, Safety and Environment Committee Director of Husky Energy Inc. since 2008	Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. (a business advisory company). Mr. Russel is a director of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd. Mr. Russel is a Professional Engineer and Qualified Commercial Mediator. He received his Master's degree in Business Administration and a degree in electronics engineering from McGill University, Canada.
Shaw, Wayne E. Ontario, Canada	Director, Member of the Corporate Governance Committee and the Health, Safety and Environment Committee Director of Husky Energy Inc. since 2000	Mr. Shaw is a Senior Partner with Stikeman Elliott LLP, Barristers and Solicitors. Mr. Shaw is also a director of the Li Ka Shing (Canada) Foundation. Mr. Shaw holds a Bachelor of Arts degree and a Bachelor of Laws degree.
Shurniak, William Saskatchewan, Canada	Director, Deputy Chair and Member of the Audit Committee Director of Husky Energy Inc. since 2000	Mr. Shurniak is a director of Hutchison Whampoa Limited and a director and Chairman of Northern Gas Networks Limited (a private distributor of natural gas in Northern England). 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, CitiPower Pty Ltd. (a utility company) since 2002, and a director of

		Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002 and 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 and in 2009 he was awarded the Saskatchewan Order of Merit.
Sixt, Frank J. Hong Kong	Director & Member of the Compensation Committee Director of Husky Energy Inc. since 2000	Mr. Sixt is Group Finance Director and Executive Director of Hutchison Whampoa Limited. Mr. Sixt is also the Non-executive Chairman and a director of TOM Group Limited; Executive Director of Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited (formerly Hongkong Electric Holdings Limited); a director of Cheung Kong (Holdings) Limited (an investment holding company); Hutchison Telecommunications International Limited (a telecommunications company); Hutchison Telecommunications (Australia) Limited (a telecommunications company) and Partner Communications Company Ltd. (a telecommunications company). Mr. Sixt is also a director of the Li Ka Shing (Canada) Foundation. 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.

Officers

Name and Residence	Office or Position	Principal Occupation During Past 5 Years
Cowan, Alister Alberta, Canada	Vice President & Chief Financial Officer	Vice President & Chief Financial Officer of Husky Energy Inc. since July 2008. He was previously Executive Vice President and Chief Financial Officer, British Columbia Hydro & Power Authority from 2004 to 2008, Vice President, Direct Energy Marketing Limited, from 2003 to 2004 and Vice President and Comptroller, TransAlta Corporation from 2000 to 2003.
Peabody, Robert J. Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Husky since January 2006. Prior to joining Husky, Mr. Peabody held the following positions with BP: Director Innovence Separation & Initial Public Offering Project from 2005 to 2006, President of Global Polymers, Chemicals from 2004 to 2005, Vice President, Polyester and Aromatics Americas from 2002 to 2004 and Vice President, BP Group Strategy & Planning from 1991 to 2001.
Girgulis, James D. Alberta, Canada	Vice President, Legal & Corporate Secretary	Vice President, Legal & Corporate Secretary of Husky since August 2000.
Lau, John C.S. Hong Kong	President and Chief Executive Officer, Asia Pacific	President and Chief Executive Officer, Asia Pacific since May 2010 when he stepped down as Chief Executive Officer of Husky Energy Inc. after 18 years in the position. Prior to joining Husky, Mr. Lau served in various senior executive roles in Cheung Kong (Holdings) Limited and Hutchison Whampoa Limited group of companies.

As at February 15, 2011, the directors and officers of Husky, as a group, beneficially owned or controlled or directed, directly or indirectly, 580,113 common shares of Husky representing less than 1% of the issued and outstanding common shares.

Conflicts of Interest

The officers and directors of Husky may also become officers and/or directors of other companies engaged in the oil and gas business generally and which may own interests in oil and gas properties in which Husky holds or may in future hold an interest. As a result, situations may 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 executive officers of Husky is or has been within the past ten years, a director, chief executive officer or chief financial officer of any company, including Husky and any personal holding companies of such person, 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 after such persons ceased to be a director, chief executive officer or chief financial officer of the company 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, which resulted from an event that occurred while such person was acting in such capacity.

In addition, none of those persons who are directors or executive officers of Husky is, or has been within the past ten years, a director or executive officer of any company, including Husky and any personal holding companies of such persons, that while such person was acting in that capacity, 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 as follows. Eva Kwok was a director of Air Canada in 2003 at the time it became subject to creditor protection under the *Companies Creditors Arrangement Act* (Canada). Until April 12, 2002, Frank Sixt was a director 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. Victor Li was a director of Star River Investment Limited, a Hong Kong company, until June 4, 2005, which commenced creditors voluntary winding up on September 28, 2004. The company was subsequently dissolved on June 4, 2005.

Individual Penalties, Sanctions or Bankruptcies

None of the persons who are directors or executive officers of Husky (or any personal holding companies of such persons) have, within the past ten years become 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 manager or trustee appointed to hold his or her assets.

None of the persons who are directors or executive officers of the Company (or any personal holding companies of such persons) 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), W. Shurniak, C.S. Russel, F.S.H. Ma and G.C. Magnus. 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 Mandate 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 a director of a number of affiliates of CIBC.

W. Shurniak — Mr. Shurniak is a non-executive director and member of the audit committee of Hutchison Whampoa Limited and a director and Chairman of Northern Gas Networks Limited, a private company. He has broad banking experience and prior to his moving back to Canada in 2005, he spent five years in Australia where he was a director of a public company engaged in the distribution of natural gas. He was also a director and member of the Audit Committee of five other private companies, three of which are regulated electricity distribution companies.

C.S. Russel — Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. Mr. Russel is a director and an Audit Committee member of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd.

F.S.H. Ma — Mr. Ma has served in senior positions in the private sector and had held Principal Official positions (minister equivalent) with the Hong Kong SAR Government. Mr. Ma is currently a member of the International Advisory Council of China Investment Corporation, China's Sovereign Fund as well as an Honorary Professor of the University of Hong Kong.

G.C. Magnus — Mr. Magnus has been a Non-executive Director of Cheung Kong (Holdings) Limited since November 2005. He is also a Non-executive Director of Hutchison Whampoa Limited, Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited.

Husky's Audit Committee Mandate 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 the fiscal years indicated:

	Aggregate fees billed by the External Auditor	
	2010	**2009**
	($ thousands)	
Audit fees	2,745	2,278
Audit-related fees	873	639
Tax fees	126	51
All other fees	—	132
	3,744	3,100

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, including the Sarbanes-Oxley Act of

2002.

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.

The audit fees disclosed in the table above reflect amounts billed in the period indicated rather than the period of the audit.

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 2010.

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 be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these or other matters or amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own or control or direct, directly or indirectly or a combination of both, more than 10% 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 reasonably be expected to materially affect the Company.

TRANSFER AGENT 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, 2010 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% of the Company's securities of any class.

KPMG LLP are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and within the meaning of the U.S. Securities Act of 1933 and the applicable rules and regulations thereunder adopted by the Securities and Exchange Commission and the Public Company Accounting Oversight Board (United States).

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 will be contained in Husky's Management Information Circular prepared in connection with the annual meeting of shareholders to be held on April 27, 2011.

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, 2010.

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

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
bpd	-barrels per day
bopd	-barrels of oil per day
mbbls/day	-thousand barrels per calendar day
boe	-barrels of oil equivalent
mboe	-thousand barrels of oil equivalent
mmboe	-million barrels of oil equivalent
boe/day	-barrels of oil equivalent per calendar day
mboe/day	-thousand barrels of oil equivalent per day
bps	-basis points
m	-metres
mcf	-thousand cubic feet
mmcf	-million cubic feet
bcf	-billion cubic feet
tcf	-trillion cubic feet
tcfe	-trillion cube feet equivalent
mmcf/day	-million cubic feet per calendar day
mcfge	-thousand cubic feet of gas equivalent
lt	-long ton
mlt	-thousand long tons
mmlt	-million long tons
lt/day	-long tons per calendar day
mlt/day	-thousand long tons per calendar day
mmbtu	-million British thermal units
km	-kilometres
sq km	-square kilometres
CO_2E	-carbon dioxide equivalent
MW	-megawatts
GJ	-gigajoule

Acronyms	
API	-American Petroleum Institute
ASP	-alkaline surfactant polymer
CDOR	-Certificate of Deposit Offered Rate
CHOPS	-cold heavy oil production with sand
CNOOC	-China National Offshore Oil Corporation
COGEH	-Canadian Oil and Gas Evaluation Handbook
EIA	-Energy Information Administration
EL	-Exploration Licence
EOR	-enhanced oil recovery
ERCB	-Energy Resources Conservation Board
FAS	-Financial Accounting Statement
FASB	-Financial Accounting Standards Board
FEED	-front end engineering design
FPSO	-Floating production, storage and offloading vessel

GAAP	-Generally Accepted Accounting Principles
LIBOR	-London Interbank Offered Rate
LLB	-Lloydminster Blend
MD&A	-Management's Discussion and Analysis
NGL	-Natural gas liquids
NIT	-NOVA Inventory Transfer
NWT	-Northwest Territories
NYMEX	-New York Mercantile Exchange
OPEC	-Organization of Petroleum Exporting Countries
PIIP	-Petroleum initially-in-place
PSC	-Production Sharing Contract
SAGD	-Steam assisted gravity drainage
SDL	-Significant Discovery Licence
SEC	-Securities and Exchange Commission of the United States
SEDAR	-System for Electronic Document Analysis and Retrieval
WCSB	-Western Canada Sedimentary Basin
WTI	-West Texas Intermediate crude oil

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.

Barrel

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

Bitumen

Bitumen is solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure.

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.

Debottleneck

To remove restrictions thus improving flow rates and productive capacity.

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

Extension well

A well drilled to extend the limits of a known reservoir.

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.

Heavy crude oil

Crude oil measured between 20 API° and 10 API° and is liquid at original temperature in the deposit and atmospheric pressure.

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.

Light crude oil

Crude oil measured at 30 API° or lighter.

Liquefied petroleum gas

Liquefied propanes and butanes, separately or in mixtures.

Medium crude oil

Crude oil measured between 20 API° and 30 API°.

Metocean data

Meteorological and oceanographic data used for, among other things, the design of marine structures.

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

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 include 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 addition 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 liquefiable hydrocarbons or other substances contained therein.

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 issued following the declaration of a significant discovery, which is indicated by the first exploration well that demonstrates by flow testing the existence of sufficient hydrocarbons in a particular geological feature to suggest potential for sustained production. A Significant Discovery Licence confers the same rights as that of an Exploration 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, 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:

$$\text{Degrees API} = \frac{141.5}{\text{Specific gravity @ F60 degrees}} - 131.5$$

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.

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 cables 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 completely or partially 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 subsurface 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 within the meaning of 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 and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements"). The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements. 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," "target," "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In particular, forward-looking statements in this Annual Information Form include, but are not limited to: the Company's general strategic plans and growth opportunities; the Company's 2011 capital program; trends affecting the oil and gas industry in Canada; the anticipated effect of costs incurred for environmental protection to Husky's financial condition and results of operations in the long term; planned expenditures on environmental upgrades and remediation in 2011; reserve and resource estimates; discounted future net cash flows relating to proved oil and gas reserves; future capital expenditures required to gain access to proved undeveloped reserves; sources of funding for future development costs; abandonment and reclamation costs; anticipated effects of asset acquisitions on the Company's reserves, production and results of operations; anticipated timing and effect of closing of the sale of the Meridian cogeneration facility; production estimates for the year ended December 31, 2011; testing and implementation of enhanced recovery and ASP injection techniques; development plans at the Company's McMullen field; exploration, development and production plans for the Company's assets in Western Canada, the oil sands, Southeast Asia and the Atlantic Region; drilling plans at the Company's properties in Western Canada, the oil sands, Southeast Asia and the Atlantic Region; anticipated project costs, development plans and production capacity for the Sunrise Energy Project; exploration, drilling and SAGD pilot project plans for the Company's undeveloped oil sands assets; exploration, development and production plans for the White Rose oil field; anticipated effects of the Terra Nova redetermination on the Company's reserves; drilling plans at Terra Nova; growth opportunities in the offshore Canadian East Coast area; seismic acquisition and exploration plans for Canada's East Coast and offshore Greenland; interpretation of seismic results from the Columbia River Basin;

expected timing and volumes of production in Western Canada, the oil sands, the Atlantic Region and in South East Asia; development and production plans for the Liwan discovery; seismic acquisitions, delineation drilling and exploration plans for the South China Sea and the East China Sea; drilling plans for the North Sumbawa II block; development and production plans for the Madura BD field; future delivery commitments of natural gas; plans and expected effects of expanding the Company's commodity marketing operations; planned expansion of the Company's heavy crude pipeline system; evaluation of additional storage opportunities in Western Canada; strategies to improve earnings in Husky's downstream business; the Company's strategy to grow its asphalt marketing business and plans to capture value through various business opportunities; planned upgrades at the Company's Lima, Toledo, and Lloydminster facilities; the Company's dividend strategy; and effects of changes in the Company's credit ratings.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this Annual Information Form are reasonable, Husky's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about Husky and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources. The material factors and assumptions used to develop the forward-looking statements include, but are not limited to:

- no significant adverse changes to energy markets, competitive conditions, the supply and demand for crude oil, natural gas, NGL and refined petroleum products, or the political, economic and social stability of the jurisdictions in which Husky operates;
- no significant delays of the development, construction or commissioning of our projects that may result from the inability of suppliers to meet their commitments, lack of regulatory approvals or other governmental actions, harsh weather or other calamitous event;
- no significant disruption of operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event;
- no significant unexpected technological or commercial difficulties that adversely affect exploration, development, production, processing or transportation;
- continuing availability of economical capital resources;
- demand for products and cost of operations;
- no significant adverse legislative and regulatory changes, in particular changes to the legislation and regulation governing fiscal regimes and environmental issues;
- stability of general domestic and global economic, market and business conditions; and
- no significant increase in the cost of major growth projects.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, 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 Husky's control, that could influence actual results include, but are not limited to:

- the demand for Husky's products and prices received for crude oil and natural gas production and refined petroleum products;
- the economic conditions of the markets in which Husky conducts business;
- the exchange rate between the Canadian and U.S. dollar;
- the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions;
- the availability of prospective drilling rights;
- the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project development;

- the availability and cost of labour, material and equipment to efficiently, effectively and safely undertake capital projects;
- the costs to operate properties, plants and equipment in an efficient, reliable and safe manner;
- potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
- prevailing climatic conditions in the Company's operating locations;
- changes to royalty regimes;
- regulations to deal with climate change issues;
- changes to government fiscal, monetary and other financial policies;
- the competitive actions of other companies, including increased competition from other oil and gas companies;
- business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect Husky and that may or may not be financially recoverable;
- the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects;
- the inability to reach estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties or other risk factors;
- changes in workforce demographics; and
- the cost and availability of capital, including access to capital markets at acceptable rates.

These and other factors are discussed throughout this Annual Information Form and in the "Management's Discussion and Analysis," available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

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

Husky Energy Inc.

Audit Committee Mandate

Purpose

The Audit Committee (the "Committee") is a committee of the Board of Directors (the "Board") of Husky Energy Inc. (the "Corporation"). The Committee's primary function is to assist the Board in carrying out its responsibilities with respect to:

1. the quarterly and annual financial statements and quarterly and annual MD&A, which are to be provided to shareholders and the appropriate regulatory agencies;
2. earnings press releases before the Corporation publicly discloses this information;
3. the system of internal controls that management has established;
4. the internal and external audit process;
5. The appointment of external auditors;
6. the appointment of qualified reserves evaluators or auditors;
7. the filing of statements and reports with respect to the Corporation's oil and gas reserves; and
8. the identification, management and mitigation of major financial risk exposures of the Corporation.

In addition, the Committee provides an avenue for communication between the Board and each of the Chief Financial Officer of the Corporation and other senior financial management, internal audit, the external auditors, external qualified reserves evaluators or auditors and internal qualified reserves evaluators. It is expected that the Committee will 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.

While the Committee has the responsibilities and powers set forth it this Mandate, the role of the Committee is oversight. The members of the Committee are not full time employees of the Corporation 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 Committee to plan or conduct financial audits or reserve audits or evaluations, or to determine that the Corporation's financial statements are complete, accurate and are in accordance with applicable accounting or reserve 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 will also have the responsibility to conduct investigations and to assure compliance with laws and regulations and the Corporation's business conduct guidelines.

Composition

The Committee will consist of not less than three directors, all of whom will be independent and will satisfy the financial literacy requirements of securities regulatory requirements.

One of the members of the Committee will be an audit committee financial expert as defined in applicable securities regulatory requirements.

Members of the Committee will be appointed annually at a meeting of the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs of the Board and will be listed in the annual report to shareholders.

Committee members may be removed or replaced at any time by the Board, and will, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Committee Chair will be appointed by the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs of the Board.

Meetings

The Committee will meet at least four times annually on dates determined by the Chair OR at the call of the Chair or any other Committee member, and as many additional times as the Committee deems necessary.

Committee members will strive to be present at all meetings either in person, by telephone or other communications facilities as permit all persons participating in the meeting to hear each other.

A majority of Committee members, present in person, by telephone, or by other permissible communication facilities will constitute a quorum.

The Committee will appoint a secretary, who need not be a member of the Committee, or a director of the Corporation. The secretary will keep minutes of the meetings of the Committee. Minutes will be sent to all Committee members, on a timely basis.

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.

As necessary or desirable, but in any case at least annually, the Committee will meet the management and representatives of the external reserves 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.

Authority

Subject to any prior specific directive by 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 Corporation and the reporting of the Corporation's reserves and oil and gas activities.

The Committee has the authority to engage and set the compensation of independent counsel and other advisors, at the Corporation's expense, as it determines necessary to carry out its duties.

In recognition of the fact that the external auditors are ultimately accountable to the Committee, the Committee will have the authority and responsibility to recommend to the Board the external auditors that will be proposed for nomination at the annual general meeting. The external auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external auditors. The Committee will approve the fees and terms for all audit engagement and all non-audit engagements with the external auditors. The Committee will consult with management and the internal audit group regarding the engagement of the external auditors but will not delegate these responsibilities.

The external qualified reserves evaluators or auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external qualified reserves evaluators or auditors. The Committee will approve the fees and terms for all reserves evaluators or audit engagements. The Committee will consult with management and the internal qualified reserves evaluators group regarding the engagement of the external qualified reserves evaluators or auditors but will not delegate these responsibilities.

Specific Duties & Responsibilities

The Committee will have the oversight responsibilities and specific duties as described below.

Audit

1. Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Corporate Governance Committee and the Board for approval.
2. Review with the Corporation's management, internal audit and the external auditors and recommend to the Board for approval the Corporation's annual financial statements and annual MD&A which is to be provided to shareholders and the appropriate regulatory agencies and any financial statement contained in a prospectus, information circular, registration statement or other similar document.
3. Review with the Corporation's management, internal audit and the external auditors and approve the Corporation's quarterly financial statements and quarterly MD&A which is to be provided to shareholders and the appropriate regulatory agencies.
4. Review with the Corporation’s management and approve earnings press releases before the Corporation publicly discloses this information.
5. Be responsible for the oversight of the work of the external auditors, including the resolution of disagreements between management of the Corporation and the external auditors regarding financial reporting.

6. Review with the Corporation's management, internal audit and the external auditors the Corporation's accounting and financial reporting controls and obtain annually, in writing from the external auditors their observations, if any, on material weaknesses in internal controls over financial reporting as noted during the course of their work.

7. Review with the Corporation's management, internal audit and the external auditors significant accounting and reporting principles, practices and procedures applied by the Corporation in preparing its financial statements, and discuss with the external auditors their judgments about the quality (not just the acceptability) of the Corporation'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 audit and how management is addressing the conditions reported.

9. Review the scope and general extent of the external auditors' annual audit, such review to include an explanation from the external auditors of the factors considered in determining the audit scope, including the major risk factors, and the external auditors confirmation 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 Corporation as contemplated by Independence Standards Board Standard No, 1, Independence Discussions with Audit Committees.

11. Arrange with the external auditors that (a) they will advise the Committee, through its Chair and management of the Corporation, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Corporation, such notification is to be made prior to the related press release and (b), for written confirmation 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. Review at the completion of the annual audit, with senior management, internal audit and the external auditors the following:

    i. the annual financial statements and related footnotes and financial information to be included in the Corporation's annual report to shareholders;

    ii. 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;

    iii. significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit;

    iv. inquire about the cooperation received by the external auditors during their audit, including access to all requested records, data and information; and

    v. 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 Corporation's financial statements.

13. Discuss (a) with the external auditors, without management being present, (i) the quality of the Corporation's financial and accounting personnel, and (ii) the completeness and accuracy of the Corporation's financial statements, and (b) elicit the comments of senior management regarding the responsiveness of the external auditors to the Corporation'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) and review the responses of management to the Letter of Comments and Recommendations and receive follow-up reports on action taken concerning the aforementioned recommendations.

15. Review and approve disclosures required to be included in periodic reports filed with Canadian and U.S. securities regulators with respect to non-audit services performed by the external auditors.

16. Establish adequate procedures for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation'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 Corporation regarding accounting, internal accounting controls or auditing matters, and (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
18. Review and approve the Corporation'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 Corporation's policies with respect to unethical or illegal activities by the Corporation's employees that may have a material impact on the financial statements or other reporting of the Corporation.
21. Reviewing generally, as part of the review of the annual financial statements, a report, from the Corporation's general counsel concerning legal, regulatory and compliance matters that may have a material impact on the financial statements or other reporting of the Corporation.
22. Review and discuss with management, on a regular basis, the identification, management and mitigation of major financial risk exposures across the Corporation.

Reserves

23. Review, with reasonable frequency, the Corporation's procedures relating to the disclosure of information with respect to the Corporation's oil and gas reserves, including the Corporation's procedures for complying with the disclosure requirements and restrictions of applicable regulatory requirements.
24. Review with management the appointment of the 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 management and the appointed external qualified reserves evaluators or auditors.
25. Review, with reasonable frequency, the Corporation'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 regulatory requirements.
26. Meet, before the approval and release of the Corporation's reserves data and the report of the qualified reserve evaluators or auditors thereon, with senior 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 or auditors.
27. Recommend to the Board for approval the content and filing of required statements and reports relating to the Corporation's disclosure of reserves data as prescribed by applicable regulatory requirements.

Miscellaneous

28. Review and approve (a) any change or waiver in the Corporation's Code of Business Conduct for the President and Chief Executive Officer and senior financial officers and (b) any public disclosure made regarding such change or waiver and, if satisfied, refer the matter to the Board for approval.
29. Act in an advisory capacity to the Board.
30. Carry out such other responsibilities as the Board may, from time to time, set forth.
31. Advise and report to the Co-Chairs of the Board and the Board, relative to the duties and responsibilities set out above, from time to time, and in such details as is reasonably appropriate.

Effective Date: November 20, 2010

Schedule B

Husky Energy Inc.

Report on Reserves Data by Qualified Reserves Evaluator

To the Board of Directors of Husky Energy Inc. (Husky):

1. Our staff has evaluated Husky's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Husky's management. As the Internal Qualified Reserves Evaluator 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.

   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 "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society). Our internal reserves evaluators are not independent of Husky, within the meaning of the term "independent" under those standards.

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions presented in the COGE Handbook.

4. The following table sets forth the evaluated estimated future net revenue (before deducting income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Husky evaluated for the year ended December 31, 2010 and reported to the Audit Committee of the Board of Directors:

Location of Reserves	Discounted Future Net Cash Flows before income taxes, 10% discount rate
	($ millions)
Canada	23,356
China	579
Indonesia	203
Libya	11
	24,150

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined in accordance with the principles and definitions presented in the COGE Handbook.

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

7. Because, the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Calgary, Alberta
February 7, 2011

/s/ Frederick Au-Yeung
Frederick Au-Yeung, P. Eng
Manager of Reservoir Engineering

Schedule C

Husky Energy Inc.

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 Husky's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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 NI 51-101. 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 by Husky's Internal Qualified Reserves Evaluator 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 qualified reserves evaluators and the external reserves auditors;

(b) met with the Internal Qualified Reserves Evaluator and external reserves auditors to determine whether any restrictions placed by management affect the ability of the Internal Qualified Reserves Evaluator and the external reserves auditors to report without reservation; and

(c) reviewed the reserves data with management, the Internal Qualified Reserves Evaluator and the external reserves auditors.

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 Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2, which is the Report on Reserves Data of Husky's Internal Qualified Reserves Evaluator; 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 reserve evaluators or auditors. Notwithstanding this exemption, we involve independent qualified reserve auditors as part of Husky's corporate governance practices. Their involvement helps assure that our internal oil and gas reserve estimates are materially correct.

In Husky's view, the reliability of Husky's 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.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

/s/ Asim Ghosh March 8, 2011

Asim Ghosh
President & Chief Executive Officer

/s/ James D. Girgulis March 8, 2011

James D. Girgulis
Vice President, Legal & Corporate Secretary

/s/ R. Donald Fullerton March 8, 2011

R. Donald Fullerton
Director

/s/ William Shurniak March 8, 2011

William Shurniak
Director

Schedule D

Husky Energy Inc.

Independent Engineer's Audit Opinion

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 net present value of these reserves of Husky Energy Inc., as at December 31, 2010. The Company's detailed reserves information were provided to us for this audit. Our responsibility is to express an independent opinion on the reserves and the respective present worth value estimates, in the aggregate, based on our audit tests and procedures.

We conducted our audit in accordance with generally accepted audit standards as recommended by the Society of Petroleum Engineers and as recommended in the Canadian Oil and Gas Evaluation Handbook (COGEH) Volume 1 Section 12. 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 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 a sufficient number of the Company's properties as considered necessary in order 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 as set out in the Canadian Oil and Gas Evaluation Handbook.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B. J. Wurster, P. Eng.
B. J. Wurster, P. Eng.
Vice President

Calgary, Alberta
January 25, 2011

Document B
Form 40-F

Consolidated Financial Statements and Auditors' Report to Shareholders

For the Year Ended December 31, 2010

MANAGEMENT'S REPORT

The management of Husky Energy Inc. ("the Company") is responsible for the financial information and operating data presented in this financial document.

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

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that our internal control over financial reporting was effective as of December 31, 2010. The system of internal controls is further supported by an internal audit function.

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

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

/s/ Asim Ghosh

Asim Ghosh

President & Chief Executive Officer

/s/ Alister Cowan

Alister Cowan

Vice President & Chief Financial Officer

Calgary, Alberta, Canada

March 8, 2011

INDEPENDENT AUDITOR'S REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Husky Energy Inc.

We have audited the accompanying consolidated financial statements of Husky Energy Inc. ("the Company") and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010, 2009 and 2008, the consolidated statements of earnings and comprehensive income, changes in shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company and its subsidiaries as at December 31, 2010, 2009 and 2008 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Other Matters

Our audits were made for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The supplementary information included in Document C in the annual report on Form 40-F entitled "Reconciliation to Accounting Principles Generally Accepted in the United States" is presented for purposes of additional analysis and requirements under securities legislation. Such supplementary information has been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic consolidated financial statements taken as a whole.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 8, 2011 expressed an unmodified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Canada

March 8, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Husky Energy Inc.

We have audited Husky Energy Inc. ("the Company")'s internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 8, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Canada

March 8, 2011

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

As at December 31 (millions of dollars)	**2010**	2009	2008
Assets			
Current assets			
Cash and cash equivalents *(note 9)*	**252**	392	913
Accounts receivable *(notes 5, 20)*	**1,529**	987	1,344
Inventories *(note 6)*	**1,935**	1,520	1,032
Prepaid expenses	**34**	12	11
	3,750	2,911	3,300
Property, plant and equipment, net *(notes 1, 7)*	**23,259**	21,254	20,839
Goodwill *(notes 1, 10)*	**663**	689	779
Contribution receivable *(notes 8, 20)*	**1,284**	1,313	1,448
Other assets *(note 20)*	**177**	128	120
	29,133	26,295	26,486
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes 12, 20)*	**2,494**	2,185	2,896
Long-term debt *(notes 13, 20)*	**4,187**	3,229	1,957
Contribution payable *(notes 8, 20)*	**1,427**	1,500	1,659
Other long-term liabilities *(note 14)*	**1,417**	1,036	898
Future income taxes *(note 15)*	**4,115**	3,932	4,713
Commitments and contingencies *(note 16)*			
Shareholders' equity			
Common shares *(note 17)*	**4,574**	3,585	3,568
Retained earnings	**10,985**	10,832	10,436
Accumulated other comprehensive income	**(66)**	(4)	359
	15,493	14,413	14,363
	29,133	26,295	26,486

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

On behalf of the Board:

/s/ Asim Ghosh

Asim Ghosh

Director

/s/ R.D. Fullerton

R.D. Fullerton

Director

Consolidated Statements of Earnings and Comprehensive Income

Year ended December 31 (millions of dollars, except share data)	**2010**	2009	2008
Sales and operating revenues, net of royalties	**18,178**	15,074	24,701
Costs and expenses			
Cost of sales and operating expenses *(note 14)*	**14,013**	10,865	17,706
Selling and administration expenses	**305**	265	284
Stock-based compensation *(note 17)*	**–**	1	(33)
Depletion, depreciation and amortization *(notes 1, 7)*	**2,073**	1,805	1,832
Interest - net *(note 13)*	**208**	194	147
Foreign exchange *(note 13)*	**(2)**	(5)	(335)
Other - net *(note 20)*	**23**	(8)	(45)
	16,620	13,117	19,556
Earnings before income taxes	**1,558**	1,957	5,145
Income taxes (recoveries) *(note 15)*			
Current	**188**	1,262	901
Future	**197**	(721)	493
	385	541	1,394
Net earnings	**1,173**	1,416	3,751
Other comprehensive income (loss)			
Cumulative foreign currency translation adjustment	**(112)**	(469)	607
Hedge of net investment, net of tax *(note 20)*	**44**	104	(165)
Derivatives designated as cash flow hedges, net of tax *(note 20)*	**6**	2	(6)
	(62)	(363)	436
Comprehensive income	**1,111**	1,053	4,187
Earnings per share			
Basic and diluted	**1.38**	1.67	4.42
Weighted average number of common shares outstanding *(millions)*			
Basic and diluted	**852.7**	849.7	849.2

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

Consolidated Statements of Changes in Shareholders' Equity

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Common shares			
Beginning of year	**3,585**	3,568	3,551
Common shares issued, net of share issue costs	**988**	–	–
Options exercised	**1**	17	17
End of year	**4,574**	3,585	3,568
Retained earnings			
Beginning of year	**10,832**	10,436	8,154
Net earnings	**1,173**	1,416	3,751
Dividends on common shares *(note 17)*	**(1,020)**	(1,020)	(1,469)
End of year	**10,985**	10,832	10,436
Accumulated other comprehensive income			
Beginning of year	**(4)**	359	(77)
Other comprehensive income			
Cumulative foreign currency translation adjustment	**(112)**	(469)	607
Hedge of net investment, net of tax *(note 20)*	**44**	104	(165)
Derivatives designated as cash flow hedges, net of tax *(note 20)*	**6**	2	(6)
	(62)	(363)	436
End of year	**(66)**	(4)	359
Shareholders' equity	**15,493**	14,413	14,363

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

Consolidated Statements of Cash Flows

Year ended December 31 (millions of dollars)	**2010**	2009	2008
Operating activities			
Net earnings	**1,173**	1,416	3,751
Items not affecting cash			
Accretion *(note 14)*	**53**	48	54
Depletion, depreciation and amortization	**2,073**	1,805	1,832
Future income taxes (recoveries)	**197**	(721)	493
Foreign exchange	**(24)**	(48)	(94)
Other	**77**	7	(90)
Settlement of asset retirement obligations *(note 14)*	**(60)**	(41)	(56)
Change in non-cash working capital *(note 9)*	**(786)**	(548)	888
Cash flow - operating activities	**2,703**	1,918	6,778
Financing activities			
Long-term debt issuance	**6,108**	3,604	949
Long-term debt repayment	**(5,028)**	(1,866)	(2,205)
Proceeds from issuance of common shares, net of share issue costs *(note 17)*	**988**	–	–
Proceeds from monetization of financial instruments	**–**	41	12
Dividends on common shares	**(1,020)**	(1,020)	(1,469)
Contribution receivable repayment *(note 8)*	**38**	–	–
Other	**(1)**	2	8
Change in non-cash working capital *(note 9)*	**–**	(167)	146
Cash flow - financing activities	**1,085**	594	(2,559)
Investing activities			
Expenditures on property, plant and equipment	**(3,852)**	(2,762)	(4,060)
Joint venture arrangement *(note 8)*	**–**	–	127
Asset sales	**7**	28	37
Contribution payable repayment *(note 8)*	**(85)**	–	–
Other	**(65)**	(10)	11
Change in non-cash working capital *(note 9)*	**67**	(289)	371
Cash flow - investing activities	**(3,928)**	(3,033)	(3,514)
Increase (decrease) in cash and cash equivalents	**(140)**	(521)	705
Cash and cash equivalents at beginning of year	**392**	913	208
Cash and cash equivalents at end of year	**252**	392	913

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Segmented Financial Information

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
Year ended December 31 ($ millions)	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Sales and operating revenues, net of royalties	**4,766**	4,452	7,889	**1,570**	1,572	2,435	**7,854**	6,984	13,544
Costs and expenses									
Operating, cost of sales, selling and general	**1,597**	1,495	1,627	**1,439**	1,461	2,053	**7,592**	6,669	13,192
Depletion, depreciation and amortization	**1,572**	1,397	1,505	**100**	34	31	**43**	36	31
Interest - net	**–**	–	–	**–**	–	–	**–**	–	–
Foreign exchange	**–**	–	–	**–**	–	–	**–**	–	–
	3,169	2,892	3,132	**1,539**	1,495	2,084	**7,635**	6,705	13,223
Earnings (loss) before income taxes	**1,597**	1,560	4,757	**31**	77	351	**219**	279	321
Current income taxes (recoveries)	**(23)**	909	585	**1**	111	84	**62**	101	126
Future income taxes (reduction)	**485**	(462)	795	**8**	(88)	21	**(3)**	(22)	(29)
Net earnings (loss)	**1,135**	1,113	3,377	**22**	54	246	**160**	200	224
Property, plant and equipment -As at December 31									
Cost	**30,711**	27,478	25,283	**1,963**	1,774	1,704	**1,100**	956	931
Accumulated depletion, depreciation and amortization	**14,189**	12,688	11,432	**644**	544	510	**437**	365	330
Net	**16,522**	14,790	13,851	**1,319**	1,230	1,194	**663**	591	601
Expenditures on property, plant and equipment -Year ended December 31 [2]	**3,171**	2,326	3,580	**176**	69	99	**40**	25	94
Total assets - As at December 31	**18,179**	16,338	15,653	**2,075**	1,427	1,322	**1,368**	1,712	1,486

[1] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.*
[2] *Excludes capitalized costs related to asset retirement obligations incurred during the period (note 14) and corporate acquisitions.*

Geographical Financial Information

	Canada			United States			Other International		
($ millions)	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Year ended December 31									
Sales and operating revenues, net of royalties	**10,405**	8,856	15,213	**7,522**	5,981	9,172	**251**	237	316
Expenditures on property, plant and equipment [1]	**3,252**	1,974	3,685	**257**	285	193	**447**	538	230
As at December 31									
Property, plant and equipment, net	**18,523**	16,624	16,234	**3,477**	3,587	4,093	**1,259**	1,043	512
Goodwill [2]	**160**	160	160	**503**	529	619	**–**	–	–
Total assets	**22,674**	20,239	20,208	**5,486**	5,363	5,744	**973**	693	534

[1] *Excludes capitalized costs related to asset retirement obligations incurred during the period (note 14) and corporate acquisitions.*
[2] *Goodwill relates to Western Canada in the upstream segment and the Lima Refinery in the downstream segment - U.S. Refining and Marketing.*

Downstream						Corporate and Eliminations [1]			Total		
Canadian Refined Products			U.S. Refining and Marketing								
2010	2009	2008	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
2,975	2,495	3,564	**7,107**	5,349	7,802	**(6,094)**	(5,778)	(10,533)	**18,178**	15,074	24,701
2,728	2,204	3,340	**6,946**	4,957	8,280	**(5,961)**	(5,663)	(10,580)	**14,341**	11,123	17,912
91	93	81	**191**	194	154	**76**	51	30	**2,073**	1,805	1,832
–	–	–	**2**	3	3	**206**	191	144	**208**	194	147
–	–	–	**–**	–	–	**(2)**	(5)	(335)	**(2)**	(5)	(335)
2,819	2,297	3,421	**7,139**	5,154	8,437	**(5,681)**	(5,426)	(10,741)	**16,620**	13,117	19,556
156	198	143	**(32)**	195	(635)	**(413)**	(352)	208	**1,558**	1,957	5,145
56	38	28	**-**	3	(24)	**92**	100	102	**188**	1,262	901
(15)	19	11	**(12)**	68	(208)	**(266)**	(236)	(97)	**197**	(721)	493
115	141	104	**(20)**	124	(403)	**(239)**	(216)	203	**1,173**	1,416	3,751
2,053	1,767	1,691	**3,939**	3,875	4,249	**519**	439	406	**40,285**	36,289	34,264
832	755	669	**543**	377	229	**381**	306	255	**17,026**	15,035	13,425
1,221	1,012	1,022	**3,396**	3,498	4,020	**138**	133	151	**23,259**	21,254	20,839
245	81	155	**257**	260	133	**67**	36	47	**3,956**	2,797	4,108
1,582	1,430	1,375	**5,078**	4,771	5,380	**851**	617	1,270	**29,133**	26,295	26,486

Total		
2010	2009	2008
18,178	15,074	24,701
3,956	2,797	4,108
23,259	21,254	20,839
663	689	779
29,133	26,295	26,486

Note 2 Nature of Operations and Organization

Husky Energy Inc. ("Husky" or "the Company") is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta, Canada.

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

Upstream includes exploration for, development and production of crude oil, natural gas and natural gas liquids. The Company's upstream operations are located primarily in Western Canada, offshore Eastern Canada, offshore Greenland, offshore China and offshore Indonesia.

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

Downstream includes refining in Canada of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian refined products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. refining and marketing).

Note 3 Significant Accounting Policies

a) Principles of Consolidation and the Preparation of Financial Statements

The consolidated financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

The consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries after the elimination of intercompany balances and transactions. The Company consolidates all investments in which it has either direct or indirect voting ownership in excess of 50%. In addition, the Company consolidates variable interest entities when it is deemed to be the primary beneficiary, and proportionately consolidates joint venture entities.

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

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

b) Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization of accretion expense, asset retirement obligations, fair value measurements, employee future benefits and amounts used in impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions. By their nature, these estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change on the financial statements.

c) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand less outstanding cheques and deposits with a maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand, the excess is reported in bank operating loans.

d) Inventories

Crude oil, natural gas, refined petroleum products and purchased sulphur inventories, other than commodity inventory held for trading, are valued at the lower of cost and net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials, parts and supplies are valued at the lower of average cost and net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Previous impairment write-downs are reversed when there is a change in the situation that caused the impairment. Commodity inventory held for trading purposes is carried at fair value less cost to sell. Any changes in fair value are included as gains or losses in other expenses during the period of change. Unrealized intersegment profits in inventories are eliminated.

e) Precious Metals

The Company uses precious metals in conjunction with catalyst as part of the downstream U.S. refining process. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in earnings.

f) Property, Plant and Equipment

i) Oil and Gas

The Company employs the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical activity, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities.

Depletion of oil and gas properties and depreciation of associated production facilities are calculated using the unit of production method, based on gross proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. Costs subject to depletion and depreciation include both the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20% or more.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until proved developed reserves have been attributed to a portion of the property or the property is determined to be impaired.

Impairment losses are recognized when the carrying amount of a cost centre exceeds the sum of:

- the undiscounted cash flow expected to result from production from proved reserves based on forecast oil and gas prices and costs;
- the costs of unproved properties, less impairment; and
- the costs of major development projects, less impairment.

The amount of impairment loss is determined to be the amount by which the carrying amount of the cost centre exceeds the sum of:

- the fair value of proved and probable reserves calculated using a present value technique that uses the cash flows expected to result from production of the proved reserves and a portion of the probable reserves discounted using a risk free rate; and
- the cost, less impairment, of unproved properties and major development projects that do not have probable reserves attributed to them.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment is provided using the straight-line method based on estimated useful lives of assets which range from five to thirty-five years. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Certain turnaround costs are deferred to other assets when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Asset Retirement Obligations

The recognition of the fair value of legal obligations associated with the retirement of tangible long-lived assets as calculated using the current estimated costs to retire the asset inflated to the estimated retirement date discounted using a credit-adjusted risk free rate, is recorded in the period that the asset is put into use, with a corresponding increase to the carrying value of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in cost of sales and operating expenses. The liability will also be adjusted to reflect revisions to the previous estimates of the undiscounted obligation. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Actual retirement expenditures are charged to the accumulated liability as incurred.

iv) Capitalized Interest

Interest is capitalized on significant major capital projects based on the Company's long-term cost of borrowing. Capitalization of interest ceases when the capital project is substantially complete and ready for its intended use.

g) Impairment or Disposal of Long-lived Assets

An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The results of operations of a component of an entity that has been disposed of, or is classified as held for sale, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) the entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

h) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on at least an annual basis or sooner if there are indicators of impairment. The Company tests impairment annually in the fourth quarter of each year. To assess impairment, the fair values of the assets and liabilities of the reporting unit are compared to their carrying amounts. If the excess of the reporting unit's fair value over its carrying amounts is greater than the carrying amount of the goodwill then there is no impairment. Any amount that the carrying amount of the goodwill exceeds the excess of the reporting unit's fair value over its carrying amount is permanent goodwill impairment. Impairment losses would be recognized in current period earnings.

i) Derivative Financial Instruments and Hedging Activities

i) Financial Instruments

All financial instruments must initially be recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: held for trading financial assets and financial liabilities, loans or receivables, held to maturity investments, available for sale financial assets, and other financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings. Unrealized gains and losses on available for sale financial assets are recognized in Other Comprehensive Income ("OCI") and are transferred to earnings when the asset is derecognized. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method.

A held for trading financial instrument includes one of the following criteria:

- is a derivative, except for those derivatives that have been designated as effective hedging instruments;
- has been acquired or incurred principally for the purpose of selling or repurchasing in the near future; or
- is part of a portfolio of financial instruments that are managed together and for which there is evidence of a recent actual pattern of short-term profit taking.

For financial assets and financial liabilities that are not classified as held for trading, the transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are added to the fair value initially recognized for that financial instrument. These costs are expensed to earnings using the effective interest rate method.

ii) Derivative Instruments and Hedging Activities

Derivative instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company may choose to designate derivative instruments as hedges. Hedge accounting continues to be optional.

At the inception of a hedge, if the Company elects to use hedge accounting, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between the hedged items and hedging items and the method for testing the effectiveness of the hedge, which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

All derivative instruments are recorded on the balance sheet at fair value in accounts receivable, other assets, accounts payable and accrued liabilities, or other long-term liabilities. Freestanding derivative instruments are classified as held for trading financial instruments. Gains and losses on these instruments are recorded in other expenses in the Consolidated Statement of Earnings in the period they occur. Derivative instruments that have been designated and qualify for hedge accounting are classified as either fair value or cash flow hedges. For fair value hedges, the gains or losses arising from adjusting the derivative to its fair value are recognized immediately in earnings along with the gain or loss on the hedged item. For cash flow hedges, the effective portion of the gains and losses is recorded in OCI until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the Consolidated Statement of Earnings, the fair value of the associated cash flow hedge is reclassified from OCI into earnings. Any hedge ineffectiveness is immediately recognized in earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting.

The Company may enter into commodity price contracts to hedge anticipated sales of crude oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or costs of sales.

The Company may enter into power price contracts to hedge anticipated purchases of electricity to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream operating expenses as the related purchases occur.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments related to foreign exchange are recorded in foreign exchange expense in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The remaining portion of the gain or loss is recorded in Accumulated Other Comprehensive Income and is adjusted for changes in the fair value of the instrument over the life of the debt.

The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in self-sustaining foreign operations. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in OCI, net of tax and are limited to the translation gain or loss on the net investment.

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

The Company may enter into foreign exchange contracts to offset its foreign exchange exposure. Gains and losses on these instruments are recorded at fair value and are recognized in other expense in the Consolidated Statement of Earnings.

For cash flow hedges that have been terminated or cease to be effective, prospective gains or losses on the derivative are recognized in earnings. Any gain or loss that has been included in Accumulated Other Comprehensive Income at the time the hedge is discontinued continues to be deferred in Accumulated Other Comprehensive Income until the original hedged transaction is recognized in earnings. However, if the likelihood of the original hedged transaction occurring is no longer

probable, the entire gain or loss in Accumulated Other Comprehensive Income related to this transaction is immediately reclassified to earnings.

Fair values of the derivatives are based on quoted market prices where available. The fair values of swaps and forward contracts are based on forward market prices. If a forward price is not available for a commodity based forward contract, a forward price is estimated using an existing forward price adjusted for quality or location.

iii) Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not clearly and closely related to those of the host contract, the terms of the embedded derivatives are the same as those of a freestanding derivative and the combined contract is not classified as held for trading or designated at fair value. The Company selected January 1, 2003 as its transition date for accounting for any potential embedded derivatives.

iv) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge and exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation. Amounts included in OCI are shown net of tax. Accumulated Other Comprehensive Income is an equity category comprised of the cumulative amounts of OCI.

j) Employee Future Benefits

In Canada, the Company provides a defined contribution pension plan and other post-retirement benefits to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. In the United States, the Company provides defined contribution plans (401(k)), a defined benefit pension plan and other post-retirement benefits.

The cost of the pension benefits earned by employees in the defined contribution pension plans is expensed as incurred. The cost of the benefits earned by employees in the other post-retirement and defined benefit plans is charged to earnings as services are rendered using the projected benefit method prorated on service. The pension expense for the defined benefit pension plans and other post-retirement benefits is based on management's best estimate of expected plan investment performance, salary escalation, retirement age, attrition, future health care costs and mortality.

The future benefit obligation is discounted using a market interest rate of high quality corporate debt securities that match the amount and timing of future benefit payments. Adjustments arising from plan amendments are amortized over the expected average remaining service lifetime ("EARSL"). Net actuarial gains and losses that exceed 10% of the greater of the fair value of the plan assets and the benefit obligation are amortized over the EARSL of the participating employees.

k) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Future income tax assets and liabilities are recognized at expected tax rates in effect when temporary differences between the tax basis and the carrying value of the Company's assets and liabilities reverse. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in earnings when substantively enacted. A valuation allowance is recorded to the extent that it is considered more likely than not that the Company will be unable to utilize future tax assets.

l) Non-monetary Transactions

Non-monetary transactions are measured based on fair value when there is evidence to support the fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business.

m) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded when title passes to an external party and payment has either been received or collection is reasonably certain. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

n) Foreign Currency Translation

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

The accounts of self-sustaining foreign operations are translated to Canadian dollars using the current rate method. Assets and liabilities are translated at the period-end exchange rate and revenues and expenses are translated at the average exchange rates for the period. Gains and losses on the translation of self-sustaining foreign operations are included in OCI.

o) Stock-based Compensation

In accordance with the Company's stock option plan, common share options may be granted to officers and certain other employees. The Company records compensation expense over the vesting period based on the fair value of options granted.

The Company's stock option plan is a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for expected cash settlements is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued to reflect changes in the market price of the Company's common shares and the net change is recognized in earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital. Accrued compensation for an option that is forfeited is adjusted to earnings by decreasing the compensation expense in the period of forfeiture.

The Company's long-term incentive program consists of a Performance Share Unit ("PSU") Plan that provides a time-vested award to certain officers and employees of the Company. PSUs entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash is contingent on the Company's total shareholder return relative to a peer group of companies. A liability for expected cash payments is accrued over the vesting period of the PSUs based on the market price of the Company's common shares and an expected vesting percentage. The liability is revalued to reflect changes in the market price of the Company's common shares and the expected vesting percentage. When PSUs vest, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount. Accrued compensation for a PSU that is forfeited is adjusted to earnings by decreasing the compensation expense in the period of forfeiture. Compensation expense is recognized in selling and administration expenses.

p) Earnings per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. The calculation of basic earnings per common share is based on net earnings divided by the weighted average number of common shares outstanding.

Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. However, since the Company has a tandem stock option plan and accrues a liability for expected cash settlements, the potential common shares issuable upon exercise associated with the stock options are not included in diluted common shares outstanding. Shares that were potentially issuable on the settlement of the capital securities were not included in the determination of diluted earnings per common share, as the Company had neither the obligation nor intention to settle amounts due through the issuance of shares.

Note 4 International Financial Reporting Standards

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), for fiscal periods beginning on or after January 1, 2011.

The Company has selected IFRS accounting policies and evaluated the first-time adoption exemptions and elections available under IFRS 1, "First-Time Adoption of International Financial Reporting Standards." The resulting anticipated impact of transition to IFRS as at January 1, 2010 and for the year ended December 31, 2010 is presented in Note 24 in accordance with IFRS in effect as at

December 31, 2010. The accounting policies and IFRS 1 election choices are subject to change as the Company is required to comply with new or revised standards or interpretations of IFRS standards that are effective up to December 31, 2011.

Note 5 Accounts Receivable

($ millions)	**2010**	2009	2008
Trade receivables	**1,159**	948	1,135
Allowance for doubtful accounts	**(19)**	(18)	(22)
Derivatives due within one year	**35**	22	111
Income taxes receivable	**346**	23	106
Other	**8**	12	14
	1,529	987	1,344

Sale of Accounts Receivable

Husky has chosen not to renew its securitization agreement, which expired on March 31, 2009. No accounts receivable had been sold under the program during 2009 and 2008.

Note 6 Inventories

($ millions)	**2010**	2009	2008
Crude oil	**1,540**	812	480
Natural gas	**134**	172	222
Refined petroleum products	**148**	451	263
Materials, supplies and other	**113**	85	67
	1,935	1,520	1,032

Write-downs of inventories to net realizable value in 2010 amounted to $35 million (2009 - $106 million; 2008 – $721 million).

Note 7 Property, Plant and Equipment

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

Administrative costs related to exploration and development activities capitalized in 2010 were $51 million (2009 - $48 million; 2008 - $43 million).

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

($ millions)	**2010**	2009	2008
Canada	**3,406**	3,125	2,703
International	**836**	827	485
	4,242	3,952	3,188

Included in International are costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. All costs, net of any associated revenues, in these cost centres have been capitalized. As at December 31, 2010, $57 million was allocated to undeveloped properties with proved reserves and $779 million was allocated to undeveloped properties without proved reserves in International. Ultimate recoverability of these costs will be dependent upon the finding and development of proved oil and natural gas reserves. For the year ended December 31, 2010, the Company completed its impairment review of pre-production cost centres and determined that there was no impairment required.

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2010 were:

Canada	2011	2012	2013	2014	2015	Price increase 2015 to 2030 *(percent)*
Crude oil *($/bbl)*	75.99	76.90	76.24	76.22	75.95	1.6
Natural gas *($/mcf)*	3.89	4.55	5.01	5.84	6.06	2.6

Note 8 Joint Ventures

a) BP

On March 31, 2008, the Company completed a transaction with BP, which resulted in the formation of a 50/50 joint venture upstream entity and a 50/50 joint venture downstream entity. Both joint ventures are being accounted for using proportionate consolidation. The amounts recorded in the consolidated financial statements represent the Company's 50% interest in the joint ventures.

The upstream entity is a partnership to which Husky has contributed the Sunrise oil sands assets with a fair value of U.S. $2.5 billion as at January 1, 2008, plus capital expenditures for the three-month period ended March 31, 2008 of $15 million. BP's contribution was U.S. $250 million cash and a contribution receivable for the balance of U.S. $2.25 billion and $15 million. The contribution receivable accretes at a rate of 6% and is payable between December 31, 2010 and December 31, 2015 with the final balance due and payable by December 31, 2015. The upstream entity is included as part of the upstream segment.

The downstream entity is a limited liability company ("LLC") to which BP has contributed the Toledo Refinery plus inventories and other net assets, less accounts payable and adjusted net earnings. Husky's contribution was U.S. $250 million cash and a contribution payable for the balance of U.S. $2.6 billion. Husky's share of the value of the amounts contributed at March 31, 2008 by both entities to the downstream LLC is described below:

($ millions)	
Cash	129
Inventory	199
Property, plant and equipment (including adjusted earnings)	1,928
Partner contribution receivable	1,331
Other assets	2
Inventory related payables	(12)
Future income tax liability	(658)
Total contribution to downstream joint venture	2,919

The contribution payable accretes at a rate of 6% and is payable between December 31, 2010 and December 31, 2015 with the final balance due and payable by December 31, 2015. The timing of payments during this period will be determined by the capital expenditures made at the refinery during this same period. The downstream entity is included as part of the U.S. Refining and Marketing segment. This entity is a self-sustaining foreign operation and has a U.S. dollar functional currency.

Summarized below are the results of operations, cash flows and financial position relating to the Company's proportional interests in its downstream joint venture:

Results of Operations *($ millions)*	**2010**	2009	2008
Revenues	**2,063**	1,799	1,843
Expenses	**2,105**	1,761	2,020
Proportionate share of net income (loss)	**(42)**	38	(177)

Cash Flows *($ millions)*	**2010**	2009	2008
Cash flow – operating activities	**(2)**	76	(90)
Cash flow – investing activities	**(86)**	(55)	(58)
Proportionate share of increase (decrease) in cash and cash equivalents	**(88)**	21	(148)

Financial Position *($ millions)*	**2010**	2009	2008
Current assets	**424**	351	245
Long-term assets	**1,800**	1,910	2,292
Current liabilities	**(218)**	(179)	(42)
Long-term liabilities	**(481)**	(528)	(666)
Proportionate share of net assets	**1,525**	1,554	1,829

Contribution Receivable *($ millions)*	**2010**	2009	2008
Beginning	**1,313**	1,448	–
Additions	**–**	–	1,220
Accretion	**76**	81	–
Received	**(38)**	–	–
Foreign exchange	**(67)**	(216)	228
Ending	**1,284**	1,313	1,448

Contribution Payable *($ millions)*	**2010**	2009	2008
Beginning	**(1,500)**	(1,659)	–
Additions	**–**	–	(1,398)
Accretion	**(87)**	(91)	–
Paid	**85**	–	–
Foreign exchange	**75**	250	(261)
Ending	**(1,427)**	(1,500)	(1,659)

b) CNOOC Southeast Asia Limited

In April 2008, a subsidiary of the Company, Husky Oil Madura Partnership ("HOMP"), entered into an agreement with CNOOC Southeast Asia Limited ("CNOOCSE"), which resulted in the acquisition by CNOOCSE of a 50% equity interest in Husky Oil (Madura) Limited ("HOML"), a subsidiary of HOMP, for a consideration of $127 million (U.S. $125 million) resulting in a gain of $69 million included in other - net in the Consolidated Statements of Earnings and Comprehensive Income. HOML holds a 100% interest in the Madura Strait Production Sharing Contract. The resulting joint venture arrangement is being accounted for using the proportionate consolidation method.

In 2010, both HOMP and CNOOCSE agreed to each sell a 10% equity share in HOML to Samudra Energy Ltd., through its affiliate SMS Development Ltd. (Refer to Note 23 c).

c) Results of Joint Ventures

The results of Husky's proportionate share of its downstream joint venture with BP are described in Note 8 a). The results from the upstream joint venture with BP and the joint venture arrangement with CNOOCSE are considered to be in the pre-production phase. As a result, any impact on the financial results of the Company subsequent to entering into these joint ventures is considered immaterial.

Note 9 Cash Flows - Change in Non-cash Working Capital

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

($ millions)	**2010**	2009	2008
Decrease (increase) in non-cash working capital			
Accounts receivable	**(530)**	235	453
Inventories	**(481)**	(651)	522
Prepaid expenses	**(17)**	–	2
Accounts payable and accrued liabilities	**309**	(588)	428
Change in non-cash working capital	**(719)**	(1,004)	1,405
Relating to:			
Operating activities	**(786)**	(548)	888
Financing activities	**–**	(167)	146
Investing activities	**67**	(289)	371

b) Other cash flow information:

($ millions)	**2010**	2009	2008
Cash taxes paid	**783**	1,323	615
Cash interest paid	**232**	200	159

Cash and cash equivalents at December 31, 2010 included $185 million of cash (2009 - $65 million; 2008 - $269 million) and $67 million of short-term investments with maturities less than three months (2009 - $327 million; 2008 - $644 million).

Note 10 Goodwill

($ millions)	**2010**	2009	2008
Balance at beginning of year	**689**	779	660
Foreign currency translation of goodwill in self-sustaining U.S. operations	**(26)**	(90)	119
Balance at end of year	**663**	689	779

Note 11 Bank Operating Loans

At December 31, 2010, the Company had unsecured short-term borrowing lines of credit with banks totalling $415 million (2009 - $395 million; 2008 - $370 million) and letters of credit under these lines of credit totalled $116 million (2009 - $133 million; 2008 - $166 million). As at December 31, 2010, bank operating loans (excluding reclassified outstanding cheques) were nil (2009 and 2008 - nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2010, the weighted average interest rate on short-term borrowings was approximately 4.1% (2009 - 6.5%; 2008 - 7.1%).

Asia Pacific Energy Ltd. and Husky Oil China Ltd., subsidiaries of Husky, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes. As at December 31, 2010 there was no balance outstanding under these facilities. The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. As at December 31, 2010, there was no balance outstanding under this credit facility (2009 and 2008 - nil).

Note 12 Accounts Payable and Accrued Liabilities

($ millions)	2010	2009	2008
Trade payables	**105**	37	93
Accrued liabilities	**2,060**	1,545	1,813
Dividend payable	**255**	255	425
Stock-based compensation	**–**	1	24
Current income taxes	**–**	270	419
Other	**74**	77	122
	2,494	2,185	2,896

Note 13 Long-term Debt

		Cdn $ Amount			U.S. $ Denominated		
($ millions)	Maturity	2010	2009	2008	2010	2009	2008
Long-term debt							
Syndicated credit facility	2012	**380**	–	–	**–**	–	–
6.25% notes [1]	2012	**398**	419	490	**400**	400	400
5.90% notes [2]	2014	**750**	785	–	**750**	750	–
3.75% medium-term notes [2]	2015	**308**	–	–	**–**	–	–
7.55% debentures [2]	2016	**209**	208	245	**200**	200	200
6.20% notes [2]	2017	**316**	312	367	**300**	300	300
6.15% notes	2019	**298**	314	367	**300**	300	300
7.25% notes	2019	**746**	785	–	**750**	750	–
5.00% medium-term notes	2020	**400**	–	–	**–**	–	–
6.80% notes	2037	**385**	405	474	**387**	387	387
Debt issue costs [3]		**(26)**	(26)	(18)	**–**	–	–
Unwound interest rate swaps		**23**	27	32	**–**	–	–
		4,187	3,229	1,957	**3,087**	3,087	1,587

[1] *A portion of the Company's debt is designated in a cash flow hedging relationship for foreign currency risk management. Refer to Note 20.*
[2] *A portion of the Company's debt is designated in a fair value hedging relationship for interest rate risk management and recorded at fair value. Refer to Note 20.*
[3] *Calculated using the effective interest rate method.*

There is no long term debt due within one year as at December 31, 2010 (2009 and 2008 - nil).

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

($ millions)	2010	2009	2008
Interest expense			
Long-term debt	**226**	193	154
Contribution payable	**87**	92	63
Short-term debt	**6**	8	5
	319	293	222
Amount capitalized	**(30)**	(16)	–
	289	277	222
Interest income			
Contribution receivable	**(77)**	(81)	(55)
Other	**(4)**	(2)	(20)
	(81)	(83)	(75)
Interest - net	**208**	194	147

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

($ millions)	**2010**	2009	2008
(Gain) loss on translation of U.S. dollar denominated long-term debt	**(90)**	(265)	134
(Gain) loss on contribution receivable	**67**	216	(228)
Other (gains) losses	**21**	44	(241)
Gain	**(2)**	(5)	(335)

Other gains and losses include realized and unrealized foreign exchange gains and losses on working capital.

Interest coverage ratios [(1)]:

	2010	2009	2008
Interest coverage ratios on long-term debt [(2)(4)]			
Earnings	**7.8**	11.1	34.4
Cash flow	**13.7**	17.4	50.9
Interest coverage ratios on total debt [(3)(4)]			
Earnings	**7.6**	10.7	33.4
Cash Flow	**13.3**	16.7	49.3

(1) *Interest coverage ratios are presented in compliance with Section 8.4 of National Instrument 44-102 Shelf Distributions.*

(2) *Interest coverage on long-term debt on an earnings basis is equal to earnings before interest expense on long-term debt and income taxes divided by interest expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before interest expense on long-term debt and current income taxes divided by interest expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*

(3) *Interest coverage on total debt on an earnings basis is equal to earnings before interest expense on total debt and income taxes divided by interest expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before interest expense on total debt and current income taxes divided by interest expense on total debt and capitalized interest. Total debt includes short and long-term debt.*

(4) *Calculated for the 12 months ended for the dates shown.*

Credit Facilities

The Company's revolving syndicated credit facility allows it to borrow up to $1.25 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a five-year committed revolving credit facility. In August 2010, Husky added a second revolving syndicated credit facility that allows the Company to borrow up to $1.5 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a four-year committed revolving credit facility. Interest rates under both revolving syndicated credit facilities vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain rating agencies to the Company's senior unsecured debt.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the $1.25 billion syndicated credit facility.

As at December 31, 2010, the Company had borrowings of $380 million under its $1.25 billion revolving syndicated credit facility and no borrowings under its $1.5 billion facility or its bilateral credit facilities. See Note 21 for debt covenants.

In July 2007, the Company obtained U.S. $1.5 billion of short-term bridge financing at an interest rate based on U.S. LIBOR, maturing June 26, 2008, to facilitate closing the acquisition of the Lima, Ohio refinery. On September 11, 2007, the Company refinanced U.S. $750 million with long-term notes. The remaining bridge financing of U.S. $750 million was repaid in June 2008.

Notes and Debentures

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009. The shelf prospectus enables Husky to offer up to U.S. $3 billion of debt securities in the United States until March 26, 2011. During the 25-month period that the shelf prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. In 2009, U.S. $1.5 billion of senior notes were issued under this shelf prospectus. The notes are unsecured and rank equally with all of Husky's other unsecured and unsubordinated indebtedness.

On December 21, 2009, Husky filed an additional debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $1 billion of debt securities in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. On March 12, 2010, Husky issued $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020. The notes are redeemable at the option of the Company at any time, subject to a make whole provision. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of Husky's other unsecured and unsubordinated indebtedness.

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 2012. During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. As of December 31, 2010, only common shares had been issued under the prospectus. (Refer to Note 17).

The 6.25% and the 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002. Interest is payable semi-annually.

The 5.90% and the 7.25% notes issued in 2009 represent unsecured securities under a trust indenture dated September 11, 2007. Interest is payable semi-annually.

The 7.55% debentures represent unsecured securities under a trust indenture dated October 31, 1996. Interest is payable semi-annually.

The 6.20% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007. During 2008, the Company repurchased U.S. $63 million of the 6.80% notes. Interest is payable semi-annually.

The notes and debentures disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread.

The Company's notes, debentures, credit facilities and short-term lines of credit rank equally.

Note 14 Other Long-term Liabilities

($ millions)	**2010**	2009	2008
Asset retirement obligations	**1,150**	793	711
Cross currency swaps *(note 20)*	**102**	92	33
Employee future benefits *(note 18)*	**92**	81	81
Capital lease obligations	**34**	36	44
Other	**39**	34	29
	1,417	1,036	898

Asset Retirement Obligations

At December 31, 2010, the estimated total undiscounted inflation-adjusted amount required to settle outstanding asset retirement obligations was $7.6 billion (2009 - $5.9 billion; 2008 - $5.4 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit-adjusted risk free rates ranging from 6.2% to 9.6%.

Changes to the asset retirement obligations were as follows:

($ millions)	**2010**	2009	2008
Asset retirement obligations at beginning of year	**793**	711	662
Liabilities incurred/acquired, net of revisions	**365**	79	56
Liabilities disposed	**(1)**	(4)	(5)
Liabilities settled	**(60)**	(41)	(56)
Accretion [1]	**53**	48	54
Asset retirement obligations at end of year	**1,150**	793	711

[1] *Accretion is included in cost of sales and operating expenses.*

Note 15 Income Taxes

The provision for income taxes in the Consolidated Statements of Earnings and Comprehensive Income reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

($ millions)	**2010**	2009	2008
Earnings (loss) before income taxes			
Canada	**1,875**	2,195	5,687
United States	**(251)**	(51)	(820)
Other foreign jurisdictions	**(66)**	(187)	278
	1,558	1,957	5,145
Statutory income tax rate *(percent)*	**29.0**	30.0	30.6
Expected income tax	**452**	587	1,574
Effect on income tax of:			
Change in statutory tax rate	**–**	(1)	–
Rate benefit on partnership earnings	**(26)**	(27)	(60)
Capital gains and losses	**(5)**	(11)	(19)
Foreign jurisdictions	**(19)**	19	(102)
Other - net	**(17)**	(26)	1
Income tax expense	**385**	541	1,394

In 2009, a tax rate benefit of approximately $1 million was recognized related to a reduction in the Ontario provincial corporate tax rate.

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

($ millions)	**2010**	2009	2008
Future tax liabilities			
Property, plant and equipment	**4,694**	4,478	5,226
Foreign exchange gains taxable on realization	**91**	81	92
Other temporary differences	**3**	23	2
	4,788	4,582	5,320
Future tax assets			
Asset retirement obligations	**325**	230	207
Loss carry forwards	**311**	369	348
Other temporary differences	**37**	51	52
	673	650	607
	4,115	3,932	4,713

At December 31, 2010, the Company had $818 million of U.S. tax losses that will expire between 2028 and 2030.

Note 16 Commitments and Contingencies

At December 31, 2010, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

($ millions)	2011	2012	2013	2014	2015	After 2015	Total
Interest on fixed rate long-term debt	232	220	207	185	158	998	2,000
Operating leases	105	96	73	64	57	117	512
Firm transportation agreements	166	142	132	161	170	3,197	3,968
Unconditional purchase obligations [1]	1,970	1,126	154	29	21	122	3,422
Lease rentals and exploration work agreements	98	66	49	160	78	491	942
	2,571	1,650	615	599	484	4,925	10,844

[1] *Includes purchases of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services and natural gas purchases.*

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters, or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

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

Note 17 Share Capital

The Company's authorized share capital is as follows:

Common shares - an unlimited number of no par value.

Preferred shares - an unlimited number of no par value, with no shares outstanding as at December 31, 2010.

Common Shares

Changes to issued common shares were as follows:

($ millions)	Number of Shares	Amount
December 31, 2007	848,960,310	3,551
Options exercised	394,500	17
December 31, 2008	849,354,810	3,568
Options exercised	506,125	17
December 31, 2009	849,860,935	3,585
Common shares issued, net of share issue costs	40,816,326	988
Options exercised	31,534	1
December 31, 2010	**890,708,795**	**4,574**

With respect to the Securities referred to in Note 13, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of $293 million via an overnight-marketed public offering. The Company also issued a total of 28.9 million common shares to the principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total gross proceeds of $707 million.

Stock Options

At December 31, 2010, 49.2 million common shares were reserved for issuance under the Company stock option plan. The stock option plan is a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the date of the award. For options granted prior to 2010, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. For options granted in 2010, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares for the five trading days following the surrender date and the exercise price of the option.

Under the terms of the original stock option plan, the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year. Performance options granted may vest in up to one-third increments if the Company's annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to its industry peer group. The ultimate number of performance options that vest will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared with its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared with its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking. Stock compensation expense related to the performance options is accrued based on the price of the common shares at the end of the period and the anticipated performance factor. This expense is recognized over the three-year vesting period of the performance options.

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

	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Options Exercisable *(thousands)*
December 31, 2007	30,131	$ 37.18	4	4,494
Granted	7,596	$ 41.18	5	
Exercised for common shares	(395)	$ 13.65	1	
Surrendered for cash	(4,132)	$ 22.50	1	
Forfeited	(2,373)	$ 41.58	3	
December 31, 2008	30,827	$ 40.10	3	7,239
Granted	1,187	$ 30.32	4	
Exercised for common shares	(506)	$ 12.57	–	
Surrendered for cash	(765)	$ 13.16	–	
Forfeited	(2,344)	$ 41.59	2	
December 31, 2009	28,399	$ 40.78	3	14,917
Granted	8,870	$ 27.95	4	
Exercised for common shares	(31)	$ 24.14	–	
Surrendered for cash	(39)	$ 23.24	–	
Forfeited	(7,658)	$ 40.50	2	
December 31, 2010	**29,541**	**$ 37.04**	**3**	**17,325**

As at December 31, 2010	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$25.41 - $29.99	9,277	$ 28.08	4	102	$ 29.81
$30.00 - $34.99	1,692	$ 31.65	3	928	$ 31.96
$35.00 - $39.99	881	$ 38.48	1	680	$ 38.04
$40.00 - $42.99	14,557	$ 41.58	1	13,976	$ 41.61
$43.00 - $45.02	3,134	$ 45.02	3	1,639	$ 45.02
	29,541	**$ 37.04**	**3**	**17,325**	**$ 41.20**

Performance Share Units

In May 2010, the Board of Directors of Husky established the Performance Share Unit Plan for certain officers and employees of the Company. A PSU is a time-vested award entitling participants to receive cash based on the Company's share price at the time of vesting. The amount of cash is contingent on the Company's total shareholder return relative to a peer group of companies. During 2010, 245,000 PSUs were granted to senior management and 25,000 PSUs were forfeited. As at December 31, 2010, 220,000 PSUs were outstanding.

Dividends

During 2010, the Company declared dividends of $1.20 per common share (2009 - $1.20 per common share; 2008 - $1.73 per common share).

Note 18 Employee Future Benefits

At December 31, 2010, the accrued benefit liability for the post-retirement health and dental care plan in Canada was $59 million (2009 - $50 million; 2008 - $43 million). The accrued benefit liabilities for the defined benefit pension plan and the post-retirement welfare plan in the U.S. were $2 million (2009 -$1 million; 2008 - less than $1 million) and $31 million (2009 - $30 million; 2008 - $38 million) respectively. The total employee future benefits liability for the Company included in other long-term liabilities was $92 million at December 31, 2010 (2009 - $81 million; 2008 - $81 million).

Canada

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

a) Defined Benefit Pension Plan

Weighted average long-term assumptions are based on independent historical and projected references and are noted below:

	2010	2009	2008
Discount rate for pension benefit expense *(percent)*	**5.7**	6.3	5.0
Discount rate for accrued benefit obligation at December 31 *(percent)*	**5.0**	5.7	6.3
Long-term rate of increase in compensation levels *(percent)*	**5.0**	5.0	5.0
Long-term rate of return on plan assets *(percent)*	**7.0**	7.0	7.0

The long-term rate of return on the plan assets was determined based on management's best estimate and the historical rates of return, adjusted periodically.

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

Benefit Obligation *($ millions)*	**2010**	2009	2008
Benefit obligation, beginning of year	**141**	132	150
Current service cost	**1**	2	2
Interest cost	**8**	8	8
Benefits paid	**(9)**	(10)	(9)
Actuarial (gains) losses	**12**	9	(19)
Benefit obligation, end of year	**153**	141	132

Fair Value of Plan Assets *($ millions)*	2010	2009	2008
Fair value of plan assets, beginning of year	**119**	110	141
Contributions	**11**	5	6
Benefits paid	**(9)**	(10)	(9)
Expected return on plan assets	**8**	8	10
Gain (loss) on plan assets	**5**	6	(38)
Fair value of plan assets, end of year	**134**	119	110

Funded Status of Plan *($ millions)*	2010	2009	2008
Fair value of plan assets	**134**	119	110
Benefit obligation	**(153)**	(141)	(132)
Excess obligation	**(19)**	(22)	(22)
Unrecognized past service costs	**1**	2	2
Unrecognized losses	**48**	46	50
Accrued benefit asset	**30**	26	30

Husky adheres to a Statement of Investment Policies and Procedures (the "Policy"). The assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The measurement date of the plan assets and the accrued benefit obligation was December 31, 2010. The most recent actuarial valuation of the plan was December 31, 2009 and the next actuarial valuation is scheduled to occur no later than December 31, 2012.

The composition of the defined benefit pension plan assets was as follows:

	2010	2009	2008
U.S. common equities	**–%**	–%	1%
Canadian common equities	**37**	32	26
International equity mutual funds	**20**	21	23
Canadian government bonds	**13**	15	18
Canadian corporate bonds	**6**	5	4
International fixed income	**–**	1	1
Canadian fixed income mutual funds	**23**	25	25
Cash and receivables	**1**	1	2
Total	**100%**	100%	100%

During 2010, Husky contributed $11.4 million to the defined benefit pension plan assets, $10.1 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute $9.2 million in 2011.

The Company amortizes the portion of the unrecognized actuarial gains or losses that exceed 10% of the greater of the accrued benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. The gains or losses that are in excess of 10% are amortized over the expected future years of service, which is currently six years.

The past service costs are amortized over the expected future years of service.

b) Post-retirement Health and Dental Care Plan

The discount rate used in the calculation of the benefit obligation at December 31, 2010 was 5.2%. The average health care cost trend rate used was 9.0% for 2011, which is reduced by 0.5% per year for eight years to 5.0% in 2019 and thereafter. The average dental care cost trend used was 4%, which remains constant.

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

Benefit Obligation *($ millions)*	2010	2009	2008
Benefit obligation, beginning of year	**65**	53	54
Current service cost	**5**	4	4
Interest cost	**4**	4	3
Benefits paid	**(1)**	(1)	(1)
Actuarial (gains) losses	**10**	5	(7)
Benefit obligation, end of year	**83**	65	53

Funded Status of Plan *($ millions)*	2010	2009	2008
Benefit obligation	**(83)**	(65)	(53)
Unrecognized losses	**24**	15	10
Accrued benefit liability	**(59)**	(50)	(43)

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

($ millions)	1% Increase	1% Decrease
Effect on total service and interest cost components	2.0	(1.4)
Effect on post-retirement benefit obligation	14.9	(12.0)

c) Pension Expense and Post-retirement Health and Dental Care Expense

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

Pension Expense *($ millions)*	2010	2009	2008
Defined benefit pension plan			
Employer current service cost	**1**	2	2
Interest cost	**8**	8	8
Expected return on plan assets	**(8)**	(8)	(10)
Amortization of net actuarial losses	**6**	7	3
	7	9	3
Defined contribution pension plan	**22**	21	20
Total expense	**29**	30	23

Post-retirement Health and Dental Care Expense *($ millions)*	2010	2009	2008
Employer current service cost	**5**	4	4
Interest cost	**4**	4	3
Amortization of net actuarial losses	**–**	–	1
Total expense	**9**	8	8

d) Future Benefit Payments

The following table discloses the current estimate of future benefit payments:

($ millions)	Defined Benefit Pension Plan	Post-retirement Health and Dental Care Plan
2011	10	1
2012	10	2
2013	10	2
2014	10	2
2015	11	3
2016 - 2020	54	18

United States

a) Defined Benefit Pension Plan

As at December 31, 2010, the benefit obligation was $13 million (2009 - $8 million; 2008 - $5 million) and the fair value of the plan assets was $8 million (2009 - $5 million; 2008 - $4 million). The discount rate used at the end of 2010 to determine the accrued benefit obligation was 4.7% (2009 - 5.4%; 2008 - 6.0%). During 2010 Husky contributed $3 million to the defined benefit pension plan assets and currently plans to contribute $3 million in 2011.

Pension expense for 2010 was $4 million (2009 - $3 million; 2008 - $2 million).

The measurement date of the plan assets and the accrued benefit obligation was December 31, 2010. The most recent actuarial valuation of the plan was January 1, 2010 and the next actuarial valuation is scheduled to occur no later than January 1, 2011.

b) Defined Contribution Pension Plan

The Company's contribution to the U.S. 401(k) plan was $2.9 million in 2010 (2009 - $3.3 million; 2008 - $2.6 million).

c) Post-retirement Welfare Plan

As at December 31, 2010, the benefit obligation was $12 million (2009 - $11 million; 2008 - $13 million). The discount rate used at the end of 2010 to determine the accrued benefit obligation was 4.9% (2009 - 5.4%; 2008 - 6.1%).

Post-retirement welfare expense for 2010 was a recovery of $2 million (2009 - $2 million recovery; 2008 - $3 million expense).

Note 19 Related Party Transactions

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors. These notes were offered through an existing base shelf prospectus, which was filed with the U.S. Securities and Exchange Commission in February 2009. The coupon rates offered were 5.90% and 7.25% for the 5- and 10-year tranches respectively. Subsequent to this offering, U.S. $65 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. These transactions were measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At December 31, 2010, the senior notes are included in long-term debt on the Company's balance sheet.

On December 7, 2010, Husky issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

A related party is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions. These transactions occur in the normal course of business and have been measured at the exchange amount. For 2010, the total value of natural gas sales to the

Meridian and other cogeneration facilities owned by TACLP was $44 million (2009 - $90 million; 2008 - $125 million). At December 31, 2010, the total value of accounts receivables related to these transactions was nil (2009 and 2008 - nil). The Company and TACLP agreed to sell the Meridian cogeneration facility in February 2011. (Refer to Note 23 d).

Note 20 Financial Instruments and Risk Factors

Details of the Company's significant accounting policies and risk management for the recognition and measurement of financial instruments and the basis for which income and expense are recognized are disclosed in Note 3, "Significant Accounting Policies."

Risk Management Overview

The Company is exposed to market risks related to the volatility of commodity prices, interest rates and foreign exchange rates. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

Husky is exposed to risk factors associated with operating in developing countries, political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

Fair Value of Financial Instruments

The Company's financial instruments as at December 31, 2010 included cash and cash equivalents, accounts receivable, contribution receivable, accounts payable and accrued liabilities, long-term debt, contribution payable, the derivative portion of cash flow hedges, fair value hedges and freestanding derivatives.

The carrying value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these items.

At December 31, 2010, the carrying value of the contribution receivable and contribution payable was $1.3 billion (2009 - $1.3 billion; 2008 - $1.5 billion) and $1.4 billion (2009 - $1.5 billion; 2008 - $1.7 billion) respectively. The fair value of these financial instruments is not readily determinable due to uncertainties regarding timing of the cash flows. Refer to Note 8, "Joint Ventures."

Derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon fair value hierarchy in accordance with CICA Handbook Section 3862. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. All of Husky's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2.

The financial instruments recorded at fair value on the balance sheet at December 31 was as follows:

($ millions)	**2010**	2009	2008
Financial assets at fair value			
Trading derivatives	**34**	22	111
Financial liabilities at fair value			
Trading derivatives	**12**	16	23

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability.

The fair value of long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. The estimated fair value of long-term debt at December 31 was as follows:

	2010		2009		2008	
($ millions)	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	**4,187**	**4,578**	3,229	3,559	1,957	1,739

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk and other price risk, for example, commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns.

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

The Company's results will also be impacted by a decrease in the price of crude oil. The Company holds crude oil inventories that are feedstock or part of the in-process inventories at its refineries. These inventories are subject to a lower of cost or net realizable value test on a monthly basis and the Company is exposed to declining crude prices.

The Company's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. 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. The majority of the Company's expenditures are in Canadian dollars.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related interest expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company has entered into cash flow hedges using cross currency debt swaps. In addition, a portion of the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a self-sustaining foreign operation and the unrealized foreign exchange gain is recorded in OCI.

To mitigate risk related to interest rates, the Company may enter into fair value hedges using interest rate swaps. The Company's objectives, processes and policies for managing market risk have not changed from the previous year.

Commodity Price Risk Management

a) Natural Gas Contracts

At December 31, 2010, the Company had the following third party offsetting physical purchase and sale natural gas contracts, which met the definition of a derivative instrument:

($ millions)	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	14,696	(1)
Physical sale contracts	(14,696)	2

These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $2 million (2009 - gain of $1 million; 2008 - gain of less than $1 million) has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

b) Natural Gas Storage Contracts

At December 31, 2010, the Company had the following third party physical purchase and sale natural gas storage contracts:

($ millions)	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	2,504	–
Physical sale contracts	(37,255)	31

The third party physical purchase and sale contracts have been recorded at their fair value in accrued liabilities and accounts receivable respectively. At December 31, 2010, the balance sheet position of these contracts was $31 million recorded in accounts receivable (2009 - $13 million in accounts receivable; 2008 - $51 million in accounts receivable). The change in the fair value of these contracts resulted in an unrealized gain of $18 million (2009 - unrealized loss of $38 million; 2008 - unrealized gain of $50 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

At December 31, 2010, the Company also had financial natural gas storage contracts. Natural gas inventories held in storage relating to these contracts are recorded at fair value. At December 31, 2010, the fair value of the inventories was $131 million (2009 - $173 million; 2008 - $222 million). The cumulative fair value change on this inventory as of December 31, 2010 was an unrealized loss of $6 million (2009 - unrealized gain of $45 million; 2008 - unrealized loss of $24 million). The change in the fair value of inventory resulted in an unrealized loss of $51 million (2009 - unrealized gain of $69 million; 2008 - unrealized loss of $24 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

c) Oil Contracts

The Company designated certain crude oil purchase and sale contracts as fair value hedges against the changes in the fair value of the inventory held in storage. The assessment of effectiveness for the fair value hedges excludes changes between current market prices and market prices on the settlement date in the future.

At December 31, 2010, the Company had the following third party crude oil purchase contracts which have been designated as a fair value hedge:

($ millions)	Volumes *(bbls)*	Fair Value
Physical purchase contracts	326,382	(2)

These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of $2 million (2009 - gain of $4 million; 2008 - n/a) has been recorded in earnings in the Consolidated Statements of Earnings and Comprehensive Income. The crude oil inventory held in storage is recorded at fair value. At December 31, 2010, the fair value of the inventory was $30 million (2009 - $124 million; 2008 - n/a), resulting in an unrealized loss of $2 million (2009 - loss of $1 million; 2008 - n/a) recorded in earnings in the Consolidated Statements of Earnings and Comprehensive Income.

The Company enters into certain crude oil purchases and sale contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered.

($ millions)	Volumes *(mbbls)*	Fair Value
Physical purchase contracts	3,001	(271)
Physical sale contracts	(3,001)	248

These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At December 31, 2010, a resulting unrealized loss of $8 million was recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. A portion of the crude oil inventory is sold to third parties. This inventory is considered held for trading and as such, has been recorded at its fair value. At December 31, 2010, the fair value of inventory was $72 million, resulting in a $6 million unrealized gain recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The Company has entered into contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at December 31, 2010, the fair value of these

contracts was $1 million resulting in a loss of $1 million (2009 - loss of $30 million) recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Interest Rate Risk Management

At December 31, 2010, the Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates with the following terms:

Notional Amount *($ millions)*		Swap Maturity	Swap Rate [1] *(percent)*	Fair Value *($ millions)*
U.S.	200	November 15, 2016	LIBOR + 417 bps	10
U.S.	300	September 15, 2017	LIBOR + 264 bps	18
U.S.	150	June 15, 2014	LIBOR + 350 bps	5
Cdn	300	March 12, 2015	CDOR + 0.83%	8

[1] *Weighted average rate.*

During 2010, these swaps resulted in an offset to interest expense amounting to $23 million (2009 - offset of less than $1 million; 2008 - offset of less than $1 million). The amortization of previous interest rate swap terminations resulted in an addition to interest expense of $2 million (2009 - offset of $3 million; 2008 - offset of $5 million).

The Company had a freestanding derivative that required the payment of amounts based on a floating interest rate of CDOR + 175 bps in exchange for receipt of payments based on a fixed interest rate of 6.95% on $200 million of long-term debt effective February 8, 2002 that expired on July 14, 2009. In 2008, the interest rate swap was discontinued as a fair value hedge as the underlying debt was redeemed. For the year ended December 31, 2009, the Company recognized a loss of less than $1 million (2008 - gain of $1 million) on the interest swap arrangements recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Foreign Currency Risk Management

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

At December 31, 2010, the Company had a cash flow hedge using the following cross currency debt swaps:

Debt	Swap Amount *($ millions)*		Canadian Equivalent *($ millions)*	Swap Maturity	Interest Rate *(percent)*	Fair Value *($ millions)*
6.25% notes	U.S.	150	211	June 15, 2012	7.41	(68)
6.25% notes	U.S.	75	89	June 15, 2012	5.65	(14)
6.25% notes	U.S.	50	59	June 15, 2012	5.67	(8)
6.25% notes	U.S.	75	88	June 15, 2012	5.61	(12)

These contracts have been recorded at fair value in other long-term liabilities. The effective portion of the gain or loss related to measuring the contract at fair value has been included in OCI. As at December 31, 2010, the unrealized foreign exchange gain of $6 million (2009 - $2 million gain; 2008 - $6 million loss), net of tax of $2 million (2009 - $1 million; 2008 - $2 million) is recorded in OCI. At December 31, 2010, the balance in Accumulated Other Comprehensive Income was $2 million (2009 - $7 million; 2008 - $10 million), net of tax of less than $1 million (2009 - $3 million; 2008 - $4 million).

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. For the year ended December 31, 2010, the impact of these contracts was a realized gain of $26 million (2009 - gain of $16 million; 2008 - loss of $34 million) recorded in foreign exchange expense.

As at December 31, 2010, the Company has designated U.S. $987 million (2009 - $687 million) of its U.S. debt as a hedge of the Company's net investments in the U.S. refining operations, which are considered self-sustaining. In 2010, the unrealized foreign exchange gain arising from the translation of the debt was $44 million (2009 - gain of $104 million), net of tax expense of $7 million (2009 - expense of $18 million), which was recorded in OCI.

Sensitivity Analysis

A sensitivity analysis for foreign currency, commodities and interest rate risks has been calculated by increasing or decreasing the interest rate or foreign currency exchange rate, as appropriate, in the fair value methodologies described in the "Fair Value of Financial Instruments" section of this note. These sensitivities represent the effect resulting from changing the relevant rates with all other variables held constant and have been applied only to financial instruments. The Company's process for determining these sensitivities has not changed during the year. All calculations are on a pre-tax basis.

The Company is exposed to interest rate risk on its interest rate swaps. As at December 31, 2010, had interest rates been 50 basis points higher and assuming all other variables remained constant, the impact to earnings before tax would have been $21 million lower (2009 - $12 million lower; 2008 - less than $1 million lower). Had interest rates been 50 basis points lower and assuming all other variables remained constant, the impact to earnings before tax would have been $24 million higher (2009 - $14 million higher; 2008 - less than $1 million higher).

The Company is exposed to interest rate and foreign currency risk on its cross currency debt swaps. As at December 31, 2010, had the Canadian dollar been 1% stronger versus the U.S. dollar and assuming all other variables remained constant, the impact to OCI would have been $1 million lower (2009 - $5 million lower; 2008 - $4 million lower). Had the Canadian dollar been 1% weaker versus the U.S. dollar and assuming all other variables remained constant, the impact to OCI would have been $6 million higher (2009 - $5 million higher; 2008 - $7 million higher). As at December 31, 2009, had the interest rates been 50 basis points higher and assuming all other variables remained constant, the impact to OCI would have been $2 million higher (2008 and 2009 - $2 million higher). Had the interest rates been 50 basis points lower and assuming all other variables remained constant, the impact to OCI would have been less than $1 million lower (2009 - $1 million lower; 2008 - $7 million lower).

The Company is exposed to foreign currency risk on its forward purchases of U.S. dollars. As at December 31, 2010, had the Canadian dollar been 1% stronger relative to the U.S. dollar and assuming all other variables remained constant, the impact to earnings before tax would have been less than $1 million lower (2009 - less than $1 million lower; 2008 - $2 million lower). Equal and offsetting impacts would have occurred had the Canadian dollar been 1% weaker relative to the U.S. dollar and assuming all other variables remained constant.

The Company is exposed to commodity price risk on its natural gas storage contracts. As at December 31, 2010, had the forward price been $0.20/mmbtu higher, the impact to earnings before tax would have been $3 million lower (2009 and 2008 - $7 million lower). Had the forward price been $0.20/mmbtu lower, the impact to earnings before tax would have been $3 million higher (2009 and 2008 - $7 million higher).

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual capital expenditure budgets, which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends. The Company's upstream capital programs are funded principally by cash provided from operating activities and available credit facilities. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company has the following available credit facilities as at December 31, 2010:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities	415	299
Syndicated bank facilities	2,750	2,370
Bilateral credit facilities	150	150
Total	3,315	2,819

In addition to the credit facilities listed above, the Company has unused capacity under shelf prospectuses of U.S. $1.5 billion and $3.0 billion, the availability of which is dependent on market conditions. The Company believes it has sufficient funding through the use of these facilities to meet its future borrowing requirements. The following are the contractual maturities of financial liabilities as at December 31, 2010:

Financial Liability *($ millions)*	2011	2012	2013	2014	2015	After 2015
Accounts payable and accrued liabilities	2,494	–	–	–	–	–
Cross currency swaps	–	447	–	–	–	–
Long-term debt	–	782	–	753	303	2,349

The following are contractual maturities of non-financial liabilities as at December 31, 2010:

Non-Financial Liability *($ millions)*	2011	2012	2013	2014	2015	After 2015
Asset retirement obligations	10	9	9	9	9	1,105

The Company's contribution payable to the joint venture with BP (refer to Note 8) is payable between December 31, 2010 and December 31, 2015, with the final balance due and payable by December 31, 2015.

The Company's objectives, processes and policies for managing liquidity risk have not changed from the previous year.

Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. The Company's accounts receivable are broad based with customers in the energy industry, midstream and end user segment and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial reassurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company did not have any customers that constituted more than 10% of total sales and operating revenues during 2010.

The Company's objectives, processes and policies for managing credit risk have not changed from the previous year.

Cash and cash equivalents include cash bank balances and short-term deposits with original maturities of less than 90 days. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amount of accounts receivable, contribution receivable, and cash and cash equivalents represents the maximum credit exposure. The Company's accounts receivable excluding income taxes receivable and doubtful accounts was aged as follows:

Aging *($ millions)*	**Dec. 31, 2010**
Current	**1,110**
Past due (1 - 30 days)	**68**
Past due (31 - 60 days)	**5**
Past due (61 - 90 days)	**4**
Past due (more than 90 days)	**15**
Total	**1,202**

The movement in the Company's allowance for doubtful accounts for 2010 was as follows:

($ millions)	
Balance at January 1, 2010	18
Provisions and revisions	1
Balance at December 31, 2010	**19**

The Company did not write off any uncollectible receivables in 2010.

Held-for-Trading Financial Liabilities

The Company's cross currency swaps have been designated as a cash flow hedge and the derivative component of the hedge meets the definition of a held-for-trading financial liability. The cross currency swap counterparties' credit profiles have not materially changed since the past year or since inception. As a result, the amount of change during the period and cumulatively in the fair value of the cross currency swaps has not been materially impacted by changes resulting from credit risk. At December 31, 2010, the amount the Company would be contractually required to pay under the cross currency swaps at maturity was $346 million higher (December 31, 2009 - $356 million higher; December 31, 2008 - $414 million higher) than their carrying amount.

Embedded Derivative

During the fourth quarter of 2008, a drilling contract previously treated as an embedded derivative no longer met the criteria and the related accounting treatment was discontinued. A loss of $71 million, after tax, was recorded in 2008 compared with a gain of $71 million, after tax, for the same period in 2007.

Note 21 Capital Disclosures

The Company's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its underlying assets. The Company considers its capital structure to include shareholders' equity and debt. To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors capital based on the current and projected ratios of debt to cash flow from operations (defined as total debt divided by earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital) and debt to capital employed (defined as total debt divided by total debt and shareholders' equity). The Company's objective is to maintain a debt to cash flow from operations ratio of less than 2.5 times and a debt to capital employed target of 25% to 35%. At December 31, 2010, debt to capital employed was 21.3% (2009 - 18.3%; 2008 - 12.0%) which was below the long-term range, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. At December 31, 2010, debt to cash flow from operations was 1.2 times (2009 - 1.3 times; 2008 - 0.3 times). The ratio may increase at certain times as a result of acquisitions. To facilitate the management of this ratio, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however the bilateral credit facilities and the syndicated credit facilities include a debt to cash flow covenant. The Company was fully compliant with this covenant at December 31, 2010.

There were no changes in the Company's approach to capital management from the previous year.

Note 22 Government Assistance

Husky has government assistance programs in place where it receives funding based on ethanol sales volume from the Lloydminster and Minnedosa ethanol plants. Applications for funding from the Department of Natural Resources and the Government of Manitoba are submitted on a monthly and quarterly basis, respectively. The programs expire in 2015. Prior to the second quarter of 2010, funding received was based on ethanol production margins. In the second quarter of 2010, amendments were made to the terms under these programs which require funding to be based on ethanol sales volume. The following government funding was received during the year:

($ millions)	**2010**	2009	2008
First Quarter	**17**	11	–
Second Quarter	**15**	16	–
Third Quarter	**9**	13	1
Fourth Quarter	**9**	13	17
Total funding received	**50**	53	18

Prior to the second quarter of 2010, funding received under these programs was recorded in cost of sales; beginning in the second quarter of 2010, the company recorded funding received under these programs in sales in the Consolidated Statements of Earnings and Comprehensive Income.

Note 23 Subsequent Events

a) ExxonMobil Asset Acquisition

On November 29, 2010, the Company announced that it had signed a purchase and sale agreement with ExxonMobil Canada Ltd. to acquire oil and natural gas properties in Alberta and northeast British Columbia for $860 million. The effective date of the transaction was December 1, 2010. The transaction closed on February 4, 2011. Total consideration at closing was $826 million.

b) Sale of Oil Sands Leases

On January 14, 2011, the Company completed a sales agreement to sell 23 square miles of mining leases in Alberta for a consideration of $200 million resulting in a gain, subject to adjustments, of approximately $177 million accounted for under IFRS. The first installment of $100 million was received on January 14, 2011; the second installment of $100 million is due and payable on January 13, 2012.

c) Completion of 10% Interest Sale of HOML

In October 2010, both HOMP and CNOOCSE agreed to each sell a 10% equity share in HOML to Samudra Energy Ltd. through its affiliate, SMS Development Ltd. ('SMS"). Following the completion of the sale, HOMP and CNOOCSE will each hold a 40% equity interest in HOML with the remaining 20% balance held by SMS. This sale closed on January 13, 2011, resulting in a gain of approximately $10 million for the Company accounted for under IFRS. Husky's share of the consideration was U.S. $12.5 million in cash and a deferred purchase price for the balance of U.S. $12.5 million which bears interest at a rate of 5% and is payable to the Company from SMS's share of future distributions.

d) Sale of the Meridian Cogeneration Facility

Husky holds a 50% interest in the Meridian cogeneration facility, a 215 MW natural gas fired cogeneration facility at the site of the Lloydminster Upgrader. TACLP is the Company's joint venture partner for the Meridian cogeneration facility. In February 2011, Husky and TACLP agreed to sell the cogeneration facility to a related party. Completion of the transaction is subject to consent from Saskatchewan Power Corporation as well as regulatory approval. The transaction is expected to be completed by April 2011.

e) Amendments to Common Share Terms

In the Special Meeting of Shareholders held on February 28, 2011, Husky's shareholders approved amendments to the common share terms, which provide the shareholders with the ability to receive dividends in common shares or in cash. Quarterly dividends would be declared in an amount expressed in dollars per common share and would be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares would be calculated by dividing the total value by the total volume of common shares traded over the 5 trading day period immediately prior to the payment date of the dividend on the common shares. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash.

Note 24 First-Time Adoption of International Financial Reporting Standards

As part of the Company's transition to IFRS, the Company has prepared the Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010 and the Statement of Total Comprehensive Income for the year ended December 31, 2010 to establish the opening balance sheet of the Company and the comparative 2010 results expected to be presented to the shareholders as part of the Company's first IFRS interim report as at March 31, 2011 and IFRS financial statements as at December 31, 2011.

For all periods up to and including the year ended December 31, 2010, the Company has prepared its financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Together with other publicly reportable enterprises in Canada starting in 2011, the Company is required to prepare consolidated financial statements in accordance with IFRS. Accordingly, in advance of the first IFRS reporting date for purposes of preparing comparative 2010 IFRS information, the Company has prepared Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010 and a Statement of Total Comprehensive Income for the year ended December 31, 2010, using the following IFRS accounting policies and IFRS 1 elections.

The IFRS accounting policies provided in this note are only those policies that are expected to differ from the Company's stated Canadian GAAP accounting policies. The Company has chosen accounting policies based on the IFRSs in effect as at December 31, 2010 and prepared an assessment of the adjustments to be made by the Company to its Canadian GAAP Consolidated Balance Sheets as at January 1, 2010 and December 31, 2010 and its comparative Canadian GAAP Total Comprehensive Income for the year ended December 31, 2010 to comply with IFRS.

The impact of transition to IFRS presented in this note may require adjustment when it is incorporated as part of the first IFRS financial statements reported to shareholders in 2011. The adjustment may arise as a result of early adoption of any IFRS issued in 2011 that become effective after December 31, 2011 or as a result of new standards, amendments to standards or interpretations thereto issued by the IASB.

Key First-Time Adoption Exemptions to be Applied

IFRS 1 allows first-time adopters certain exemptions from retrospective application of certain IFRSs.

The Company plans to apply the following exemptions:

- Certain oil and gas assets in property, plant and equipment on the balance sheet were recognized and measured on a full cost basis in accordance with Canadian GAAP. The Company has elected to measure its Canadian properties at the amount determined under Canadian GAAP as at January 1, 2010. Costs included in the full cost pool on January 1, 2010 were allocated on a pro-rata basis to the underlying assets on the basis of proved developed reserve volumes as at January 1, 2010. Associated decommissioning assets were also measured at their carrying value under previous Canadian GAAP while all decommissioning liabilities were measured using a consistent credit-adjusted risk free rate, with a corresponding adjustment recorded to opening retained earnings. The Company has elected not to apply the IFRS 1 full cost exemption to its International upstream properties.
- IFRS 3, "Business Combinations," has not been applied to acquisitions of subsidiaries or interests in joint ventures that occurred before January 1, 2010.
- The Company has elected to apply International Accounting Standards ("IAS") 23, "Borrowing Costs," with an effective date of January 1, 2003 which requires mandatory capitalization of borrowing costs directly attributable to the acquisition, construction or production of qualifying assets. De-recognition of previously capitalized borrowing costs in accordance with Canadian GAAP did not have a material impact to the Company.
- The Company has recognized all cumulative actuarial gains and losses on pensions and other post-retirement benefits in retained earnings as at January 1, 2010.
- Cumulative currency translation differences for all foreign operations are deemed to be zero as at January 1, 2010. Accordingly, all cumulative foreign exchange gains and losses in the Company's cumulative foreign currency translation account have been recognized in retained earnings at January 1, 2010.
- IFRS 2, "Share-based Payment," has not been applied to equity instruments related to stock-based compensation arrangements that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010. For cash-settled share-based payment transactions, the Company has not applied IFRS 2 to liabilities that were settled before January 1, 2010.
- The Company has not reassessed any arrangements to determine whether they contain a lease if they have already been assessed under Canadian GAAP. Additionally, any arrangements that have not been assessed under Canadian GAAP have been assessed under International Financial Reporting Interpretations Committee ("IFRIC") 4, "Determining Whether an Arrangement Contains a Lease," based on terms and conditions existing at January 1, 2010.

Significant Changes in Accounting Policies

Please refer to the notes that follow the detailed reconciliations.

Reconciliation of Equity at January 1, 2010 (Date of Transition to IFRS)

(millions of dollars)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	392	–	392
Accounts and notes receivable	987	–	987
Inventories	1,520	–	1,520
Prepaid expenses	12	–	12
	2,911	–	2,911
Exploration and evaluation assets *(notes a, d, j)*	–	1,943	1,943
Property, plant and equipment *(notes a, c, d, e, f, h)*	21,288	(2,704)	18,584
Goodwill	689	–	689
Contribution receivable	1,313	–	1,313
Other assets *(note b)*	94	(26)	68
	26,295	(787)	25,508
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	1,915	26	1,941
Income taxes payable	270	–	270
	2,185	26	2,211
Long-term debt	3,229	–	3,229
Other long-term financial liabilities	96	–	96
Other long-term liabilities *(notes b, c, d, g, i)*	147	137	284
Contribution payable	1,500	–	1,500
Asset retirement obligations *(notes d, f)*	793	(26)	767
Deferred tax liabilities *(note l)*	3,932	(227)	3,705
	11,882	(90)	11,792
Shareholders' equity			
Common shares	3,585	–	3,585
Retained earnings *(note m)*	10,832	(733)	10,099
Other reserves *(note d)*	(4)	36	32
	14,413	(697)	13,716
	26,295	(787)	25,508

Reconciliation of Equity at December 31, 2010

(millions of dollars)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	252	–	252
Accounts and notes receivable	1,529	–	1,529
Inventories	1,935	–	1,935
Prepaid expenses	34	–	34
	3,750	–	3,750
Exploration and evaluation assets *(notes a, d, j)*	–	472	472
Property, plant and equipment *(notes a, c, d, e, f, h, j)*	23,299	(1,529)	21,770
Goodwill	663	–	663
Contribution receivable	1,284	–	1,284
Other assets *(note b)*	137	(26)	111
	29,133	(1,083)	28,050
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	2,494	12	2,506
Long-term debt	4,187	–	4,187
Other long-term financial liabilities	102	–	102
Other long-term liabilities *(notes b, c, d, g, i)*	165	124	289
Contribution payable	1,427	–	1,427
Asset retirement obligations *(notes d, f)*	1,150	48	1,198
Deferred tax liabilities *(note l)*	4,115	(348)	3,767
	13,640	(164)	13,476
Shareholders' equity			
Common shares	4,574	–	4,574
Retained earnings *(note m)*	10,985	(959)	10,026
Other reserves *(notes b, d)*	(66)	40	(26)
	15,493	(919)	14,574
	29,133	(1,083)	28,050

Reconciliation of Total Comprehensive Income for the Year ended December 31, 2010

(millions of dollars)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Revenues, net of royalties *(notes d, k)*	18,178	(854)	17,324
Costs and expenses			
Purchase of crude oil and products *(notes d, k)*	11,651	(854)	10,797
Production and operating expenses	2,309	–	2,309
Selling, general and administrative expenses *(notes d, g)*	305	(14)	291
Depletion, depreciation and amortization *(notes a, c, d, e, h)*	2,073	(81)	1,992
Exploration and evaluation expenses *(note a)*	–	438	438
Other - net *(notes f, i)*	23	(38)	(15)
	16,361	(549)	15,812
Profit from operating activities	1,817	(305)	1,512
Financial items			
Net foreign exchange gains (losses) *(note d)*	2	(51)	(49)
Finance income	79	–	79
Finance expenses *(notes d, f, j, i)*	(340)	15	(325)
	(259)	(36)	(295)
Profit before income taxes	1,558	(341)	1,217
Provisions for (recovery of) income taxes			
Current	188	–	188
Deferred *(note l)*	197	(115)	82
Profit	1,173	(226)	947
Other comprehensive income (loss)			
Exchange differences on translation of foreign operations, net of tax *(note d)*	(112)	21	(91)
Actuarial gains (losses) on pension plans, net of tax *(note b)*	–	(14)	(14)
Hedge of net investment, net of tax *(note d)*	44	(3)	41
Derivatives designated as cash flow hedges, net of tax	6	–	6
Total comprehensive income for the year	1,111	(222)	889

Notes to the Reconciliations of Equity and Total Comprehensive Income from Canadian GAAP to IFRS

a) IFRS 6 Adjustments – Exploration for and Evaluation of Mineral Resources

i) Accounting for Oil and Gas Properties

Under Canadian GAAP, the Company followed the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves were capitalized and accumulated within cost centres on a country-by-country basis. Depletion of oil and gas properties was calculated using the unit-of-production method based on proved oil and gas reserves for each cost centre. Under IFRS, pre-exploration and evaluation costs, which include all exploratory costs incurred prior to the acquisition of the legal right to explore, are expensed as incurred. After the legal right to explore is acquired, land acquisition costs and expenditures directly associated with exploratory wells will be capitalized as exploration and evaluation assets. Geological and geophysical and other exploration costs will be immediately recognized in exploration and evaluation expenses. Land acquisition costs will remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Land acquisition costs associated with successful exploration are reclassified into property, plant and equipment. Exploratory wells will remain capitalized until the drilling operation is complete and the results have been evaluated. If the well does not encounter reserves of commercial quantity, either on its own or in combination with other exploration wells associated with the same area of exploration, the costs of drilling the well or wells will be written-off to exploration and evaluation expenses. Wells that result in commercial quantities of reserves remain capitalized and reclassified into property, plant, and equipment.

The Company has elected to apply the IFRS 1 exemption for its Canadian oil and gas assets. For International cost centres where the Company has elected not to apply the IFRS 1 deemed cost exemption, previously capitalized costs related to unsuccessful exploration drilling, geological and geophysical expenditures, exploratory seismic and lease rental expenses have been recorded as a reduction to property, plant and equipment and opening retained earnings upon adoption of IFRS 6. As a result, inception to January 1, 2010 exploration activities that would have been expensed under IFRS totaled $516 million. For the year ended December 31, 2010, the Company reduced net property, plant, and equipment by $438 million, in accordance with IFRS 6, and recognized these amounts as exploration and evaluation expenses for all cost centres.

ii) Depletion Expense

The application of IFRS oil and gas accounting policies resulted in differences in the carrying costs subject to depletion under IFRS as compared to full cost accounting. Additionally, differences in depletion arose from the determination of depletion at the field level under IFRS versus a country level under full cost accounting. For the year ended December 31, 2010, the Company has recognized reduced depletion, depreciation and amortization of $173 million under IFRS when compared to full cost accounting for International oil and gas properties and increased depletion, depreciation and amortization of $129 million under IFRS when compared to full cost accounting for Canadian oil and gas properties. This net reduction in depletion expense can be explained in part due to the opening adjustment to International oil and gas assets as described above.

iii) Exploration and Evaluation Assets

Under IFRS 6, management has assessed the classification of activities designated as developmental or exploratory, which then determines the appropriate accounting treatment and classification of the costs incurred. For capitalized costs associated with exploratory activities, the Company has presented these costs separately on the balance sheet. Costs totalling $1,939 million as at January 1, 2010 and $477 million as at December 31, 2010 were reclassified from property, plant, and equipment to exploration and evaluation assets.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Increase in exploration and evaluation expenses	438
Decrease in depletion, depreciation and amortization	(44)
Adjustment before income taxes	394

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease/(increase) in exploration and evaluation assets	(1,939)	(477)
Decrease in property, plant and equipment	2,455	1,387
Decrease in retained earnings	516	910

b) IAS 19 Adjustments – Employee Benefits

Unamortized net actuarial loss and past service costs

IAS 19 allows the Company to recognize the unamortized net actuarial loss and past service costs for its defined benefit pension plans immediately in other comprehensive income. Canadian GAAP requires amortization of these losses and costs to net earnings over the estimated average remaining service life, with disclosure of the total cumulative unrecognized amount in the notes to the consolidated financial statements. Upon adoption of IAS 19 at January 1, 2010, the Company recognized a decrease of $65 million and an increase of $12 million in opening retained earnings related to the Company's cumulative unrecognized actuarial losses and past service cost recoveries, respectively. An additional charge to other comprehensive income of $20 million (before taxes of $6 million) was recorded in other comprehensive income representing unamortized net actuarial loss for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in other comprehensive income, before income taxes	20
Adjustment before income taxes	20

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in other assets	26	26
Increase in other long-term liabilities	27	47
Decrease in retained earnings	53	53
Decrease in other reserves	–	20

c) IAS 20 Adjustments – Government Grants

Under IAS 20, government grants are recognized when there is reasonable assurance that the entity will comply with the conditions attached to them and the grants will be received. Under Canadian GAAP, government grants are recognized when received. The Company received government grants for the expansion of its ethanol plants which are subject to repayments dependent on the profitability of its operations as assessed annually until 2015. The Company does not have reasonable assurance of the amounts repayable on the grant until the repayment requirements are fulfilled. At January 1, 2010, the Company de-recognized these government grants until reasonable assurance of the measurement of repayments is determinable which increased property, plant, and equipment and other long-term liabilities by $15 million as at January 1, 2010 and December 31, 2010. The reclassification from property, plant, and equipment would have resulted in increased depletion, depreciation and amortization of $2 million from inception to January 1, 2010; this amount was recorded as a reduction of property, plant, and equipment and opening retained earnings. For the year ended December 31, 2010, the reclassification of government grants increased depletion, depreciation and amortization by less than $1 million.

d) IAS 21 Adjustments – The Effects of Changes in Foreign Exchange Rates

Under IFRS, the functional currency of an entity is determined by focusing on the primary economic environment in which it operates and less precedence is placed on factors regarding the financing from and operational involvement of the reporting entity which consolidates the entity in its financial statements. Under Canadian GAAP, equal precedence is placed on all factors. The effect of this change to IFRS resulted in two entities having a different functional currency than the Company's functional currency. As such, the translation of the results and balance sheet of the foreign operations into the Company's presentation currency requires a translation of all assets and liabilities at the closing rate at each reporting date with all resulting foreign exchange gains or losses recognized in other comprehensive income. Revenues and expenses of foreign operations are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions with foreign exchange differences recognized in other comprehensive income. The retrospective application of IAS 21 resulted in a cumulative foreign currency exchange loss on revaluation of $29 million as at January 1, 2010 which was recognized in other reserves prior to applying the IFRS 1 exemption.

The Company elected to utilize the IFRS 1 exemption to deem all foreign currency translation differences of $36 million that arose prior to the date of transition with respect to all foreign operations to be nil at the date of transition. The Company reversed the balance of exchange differences on translation of foreign operations within other reserves and recorded a decrease to opening retained earnings of $65 million.

For the year ended December 31, 2010, net foreign exchange losses of $53 million and gain of $21 million were attributed to the above mentioned entities that were assessed as having a different functional currency than the Company's functional currency under IFRS; these amounts were recorded to profit and other comprehensive income (loss) respectively.

For the year ended December 31, 2010, the Company reclassified $3 million of foreign exchange loss on translation of its foreign operations from other reserves to profit under Canadian GAAP. Under IFRS, this reclassification is not required until the foreign operation is partially or fully disposed. The Company recorded increased net foreign exchange gains and reduced other comprehensive income of $3 million under IFRS for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in revenues, net of royalties	2
Increase/(decrease) in purchases of crude oil and other products	(2)
Increase/(decrease) in selling, general and administrative expenses	(1)
Increase/(decrease) in depletion, depreciation and amortization	(1)
Decrease in net foreign exchange gains	51
Increase in finance expenses	1
Adjustment before income taxes	50

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in exploration and evaluation assets	39	11
Decrease/(increase) in property, plant and equipment	(4)	58
Increase/(decrease) in accounts payable and other accrued liabilities	3	–
Increase/(decease) in asset retirement obligations	(9)	(8)
Decrease in retained earnings	65	115
Decrease (increase) in other reserves	(36)	(54)

e) IAS 36 Adjustments – Impairment of Assets

Under Canadian GAAP, impairment of long-lived assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on discounted cash flows compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition under IFRS, where a long-lived asset does not generate largely independent cash inflows, the Company is required to perform its test at a cash generating unit level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. Canadian GAAP impairment is based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows.

With the adoption of IAS 36, the Company recorded impairments on its ethanol plants decreasing property, plant, and equipment by $91 million as at January 1, 2010 based on their recoverable amounts using a fair value less cost to sell valuation based on a 39 year cash flow projection discounted at a pre-tax rate of 11%. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $3 million.

The adoption of IAS 36 and application of the full cost exemption also resulted in an impairment of the carrying value of oil and gas properties in the East Central Alberta and Foothills West districts decreasing property, plant, and equipment by $66 million as at January 1, 2010. The recoverable amounts were based on fair value less cost to sell valuations using proved plus probable reserve life discounted at pre-tax rates ranging from 13% to 14%. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $7 million.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in depletion, depreciation and amortization	(10)
Adjustment before income taxes	(10)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in property, plant and equipment	157	147
Decrease in retained earnings	157	147

f) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets

i) Asset Retirement Obligations

Consistent with IFRS, decommissioning provisions (asset retirement obligations) have been previously measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under IAS 37, asset retirement obligations will continue to be discounted using a credit-adjusted risk free rate, however, the liability is required to be re-measured based on changes in estimates including discount rates.

For asset retirement obligations associated with Canadian oil and gas properties where the IFRS 1 exemption was utilized, the Company re-measured asset retirement obligations as at January 1, 2010 under IAS 37 with a corresponding adjustment to opening retained earnings. The carrying values of Canadian oil and gas assets associated with asset retirement obligations under Canadian GAAP were not adjusted on transition to IFRS. This resulted in a decrease in asset retirement obligations and an increase in opening retained earnings of $13 million as at January 1, 2010. Accordingly for the year ended December 31, 2010, the Company recorded reduced accretion of $3 million under IFRS. At December 31, 2010, the Company re-measured the asset retirement obligations based on a change in the discount rate from 6.4% to 6.2% which increased property, plant, and equipment and asset retirement obligations by $66 million.

The total impact of this change to asset retirement obligations of Canadian oil and gas assets subject to the IFRS 1 exemption is summarized as follows:

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in finance expenses	3
Adjustment before income taxes	3

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in property, plant and equipment	–	66
Decrease/(increase) in asset retirement obligations	13	(50)
Increase in retained earnings	13	16

For asset retirement obligations associated with international oil and gas assets, midstream, downstream and corporate assets that were not subject to the IFRS 1 exemption, a retrospective application of IAS 37 was performed. This resulted in an increase in net property, plant, and equipment of $38 million as at January 1, 2010 and an incremental increase of $11 million during the year ended December 31, 2010. Asset retirement obligations decreased by $4 million as at January 1, 2010 and increased by an incremental $10 million for the year ended December 31, 2010. For the year ended December 31, 2010, the Company recorded reduced accretion of $1 million in pre-tax finance expenses.

The total impact of this change to asset retirement obligations associated with international oil and gas assets, midstream, downstream and corporate assets is summarized as follows:

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in finance expenses	1
Adjustment before income taxes	1

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in property, plant, and equipment	38	49
Decrease/(increase) in asset retirement obligations	4	(6)
Increase in retained earnings	42	43

Under Canadian GAAP accretion of the asset retirement obligations was included in cost of sales and operating expenses; however, under IFRS accretion is now classified in finance expenses.

ii) Onerous Contracts

Under IAS 37, contracts that are deemed loss-making or onerous are recognized as a present obligation when the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received from the contract. There are no equivalent requirements under Canadian GAAP. The Company recorded a provision for a drilling rig commitment that was deemed onerous resulting in an increase in provisions of $1 million at January 1, 2010 recorded in accounts payable and accrued liabilities with a corresponding decrease in retained earnings. For the year ended December 31, 2010, the Company recognized an additional provision of $1 million with a corresponding expense recorded to other - net.

g) IFRS 2 Adjustments – Share-Based Payments

The Company has granted cash-settled share-based payments to certain employees in the past. Under IFRS the related liability is adjusted to reflect the fair value of the outstanding cash-settled shared-based payment using an option pricing model. Canadian GAAP permitted share-based payments to be accounted for by reference to their intrinsic value.

The impact of this change is summarized as follows:

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in selling, general and administrative expenses	(13)
Adjustment before income taxes	(13)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in accounts payable and accrued liabilities	22	10
Increase in other long-term liabilities	10	9
Decrease in retained earnings	32	19

h) IAS 16 Adjustments – Property, Plant and Equipment

The Company reviewed the major components and useful lives of items of property, plant, and equipment. As a result of the retroactive treatment of component depreciation, the Company decreased property, plant and equipment by $144 million with an adjustment to opening retained earnings.

The Company also reviewed replacement of major components to determine if assets replaced prior to the end of their useful life required derecognition under IFRS. The Company determined that asset components with a net book value of $3 million required derecognition which was recorded as a decrease to opening retained earnings.

As a result of these adjustments which reduced the net book value of assets on transition to IFRS, the Company recognized reduced pre-tax depletion, depreciation and amortization of $26 million for the year ended December 31, 2010. For the year ended December 31, 2010, the Company recognized $2 million on component disposal recorded as an expense to other - net.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in depletion, depreciation and amortization	(26)
Increase in other - net	2
Adjustment before income taxes	(24)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Decrease in property, plant and equipment	147	123
Decrease in retained earnings	147	123

i) IFRS 3 Adjustments – Business Combinations

Given that the Company elected to apply the IFRS 1 exemption which permits no adjustments to amounts recorded for acquisitions that occurred prior to January 1, 2010, no retrospective adjustments are required. The Company acquired the remaining interest in the Lloydminster upgrader from the Minister of Natural Resources in 1995 and is required to make payments to the Minister from 1995 to 2014 based on average differentials between heavy crude oil feedstock and the price of synthetic crude oil sales. Under IFRS, the Company is required to recognize this contingent consideration at its fair value as part of the acquisition and record a corresponding liability. Under Canadian GAAP, any contingent consideration is not required to be recognized unless amounts are resolved and payable on the date of acquisition. On transition to IFRS, Husky recognized a liability of $85 million, based on the fair value of remaining upside interest payments, with an adjustment to opening retained earnings. For the year ended December 31, 2010, the Company recognized pre-tax accretion of $9 million in finance expenses under IFRS. Changes in forecast differentials used to determine the fair value of the remaining upside interest payments resulted in the recognition of a pre-tax gain of $41 million recorded to other income for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Increase in finance expenses	9
Increase/(decrease) in other - net	(41)
Adjustment before income taxes	(32)

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in other long-term liabilities	85	53
Decrease in retained earnings	85	53

j) IAS 23 Adjustments – Borrowing Costs

The Company has elected to commence mandatory capitalization of all major capital projects as at January 1, 2003, representing the date the Company commenced incurring capital expenditures on its Madura and Liwan projects, as permitted under IFRS 1. As a result, borrowing costs on major capital International upstream exploratory projects increased exploration and evaluation assets by $43 million as at January 1, 2010 with an adjustment to opening retained earnings.

During the year ended December 31, 2010, the major capital projects with capitalized borrowing costs under IFRS were transferred to the development phase and therefore $43 million of capitalized borrowing costs were reclassified to property, plant and equipment. Additionally, the Company capitalized incremental borrowing costs of $6 million in exploration and evaluation assets and $15 million in property, plant, and equipment under IFRS with a corresponding adjustment to finance expenses for the year ended December 31, 2010.

Consolidated Statement of Total Comprehensive Income *($ millions)*	For the year ended December 31, 2010
Decrease in finance expenses	21
Adjustment before income taxes	21

Consolidated Balance Sheets *($ millions)*	As at January 1, 2010	As at December 31, 2010
Increase in exploration and evaluation assets	43	6
Increase in property, plant and equipment	–	58
Increase in retained earnings	43	64

k) IAS 18 Adjustments – Revenue

Under IFRS, realized and unrealized gains and losses on natural gas purchase and sale contracts are recorded on a net basis against sales and operating expenses. Under Canadian GAAP, these gains and losses are recorded on a gross basis. For the year ended December 31, 2010, the Company reclassified $852 million of losses on natural gas purchase contracts from purchases of crude oil and products to revenues.

l) IAS 12 Adjustments – Income Taxes

Nearly all recognized IFRS conversion adjustments as discussed in this transition note have related effects on deferred taxes. The tax impact of the above changes (increased)/decreased the deferred tax liability as follows:

(millions of dollars)	As at Jan. 1, 2010	For the year ended, Dec. 31, 2010	As at Dec. 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	154	114	268
Depletion of oil and gas properties *(note a)*	–	(11)	(11)
Employee benefits *(note b)*	16	6	22
Foreign currency translation *(note d)*	7	13	20
Impairment of assets *(note e)*	47	(3)	44
Asset retirement obligations *(note f)*	(16)	(1)	(17)
Share-based payments *(note g)*	10	(4)	6
Property, plant and equipment *(note h)*	44	(7)	37
Business combinations *(note i)*	25	(8)	17
Borrowing costs *(note j)*	(13)	(5)	(18)
Uncertain tax positions *(note l)*	(47)	27	(20)
Decrease in deferred tax liability	227	121	348

Under IFRS, the Company records and measures income tax uncertainties based on a single best estimate. Under Canadian GAAP the Company recorded uncertain tax positions if such positions were probable of being sustained. The impact of this change increased the deferred tax liability by $47 million as at January 1, 2010 and $20 million as at December 31, 2010 under IFRS.

m) Opening Retained Earnings Adjustments

The above changes (increased)/decreased retained earnings (each net of related tax) as follows:

(millions of dollars)	As at Jan. 1, 2010	For the year ended, Dec. 31, 2010	As at Dec. 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	362	324	686
Depletion of oil and gas properties *(note a)*	–	(33)	(33)
Employee benefits *(note b)*	37	–	37
Government grants *(note c)*	2	–	2
Foreign currency translation *(note d)*	58	37	95
Impairment of assets *(note e)*	110	(7)	103
Asset retirement obligations *(note f)*	(39)	(3)	(42)
Provisions – onerous contracts *(note f)*	1	1	2
Share-based payments *(note g)*	22	(9)	13
Property, plant and equipment *(note h)*	103	(17)	86
Business combinations *(note i)*	60	(24)	36
Borrowing costs *(note j)*	(30)	(16)	(46)
Uncertain tax positions *(note l)*	47	(27)	20
Decrease in retained earnings	733	226	959

n) Reclassifications

Certain amounts have been reclassified to conform with current presentation.

o) Adjustments to the Company's Cash Flow Statement under IFRS

The highlighted reconciling items discussed above between Canadian GAAP and IFRS policies have no net impact on the cash flows generated by the Company.

Document C
Form 40-F

Reconciliation to Accounting Principles Generally Accepted in the United States

Reconciliation to Accounting Principles Generally Accepted in the United States

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

Consolidated Statements of Earnings

($ millions, except per share amounts)	**2010**	2009	2008
Net earnings under Canadian GAAP	**$ 1,173**	$ 1,416	$ 3,751
Adjustments:			
Full cost accounting [(a)]	**32**	(17)	22
Related income taxes	**(9)**	5	(6)
Unrealized (gain)/loss on natural gas inventory [(h)]	**45**	(45)	-
Related income taxes	**(13)**	13	-
Stock-based compensation [(d)]	**13**	7	(2)
Related income taxes	**(3)**	(2)	-
Net earnings under U.S. GAAP	**$ 1,238**	$ 1,377	$ 3,765
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic and diluted	**852.7**	849.7	849.4
Earnings per share under U.S. GAAP			
Basic and diluted	**$ 1.45**	$ 1.62	$ 4.43

Condensed Consolidated Balance Sheets

	2010		2009		2008	
($ millions)	**Canadian GAAP**	**U.S. GAAP**	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Current assets [h] [j]	**$ 3,750**	**$ 3,565**	$ 2,911	$ 2,866	$ 3,300	$ 3,300
Property, plant and equipment, net [a]	**23,259**	**22,922**	21,254	20,886	20,839	20,487
Other assets [b] [g]	**2,124**	**2,120**	2,130	2,131	2,347	2,335
	$ 29,133	**$ 28,607**	$ 26,295	$ 25,883	$ 26,486	$ 26,122
Current liabilities [d] [g] [j]	**$ 2,494**	**$ 2,332**	$ 2,185	$ 2,219	$ 2,896	$ 2,927
Long-term debt [b]	**4,187**	**4,213**	3,229	3,255	1,957	1,975
Other long-term liabilities [d] [g]	**2,844**	**2,862**	2,536	2,549	2,557	2,566
Future income taxes [a] [d] [g] [h]	**4,115**	**3,982**	3,932	3,778	4,713	4,576
Share capital [e] [f]	**4,574**	**4,808**	3,585	3,819	3,568	3,802
Retained earnings	**10,985**	**10,515**	10,832	10,297	10,436	9,940
Accumulated other comprehensive income						
Derivatives designated as cash flow hedges, net of tax	**(2)**	**(2)**	(8)	(8)	(10)	(10)
Cumulative foreign currency translation	**(156)**	**(156)**	(37)	(37)	432	432
Hedge of net investment, net of tax	**92**	**92**	41	41	(63)	(63)
Pension obligation [g]	**-**	**(39)**	-	(30)	-	(23)
	$ 29,133	**$ 28,607**	$ 26,295	$ 25,883	$ 26,486	$ 26,122

Condensed Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

	2010		2009		2008	
($ millions)	**Canadian GAAP**	**U.S. GAAP**	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Retained earnings, beginning of year	**$ 10,832**	**$ 10,297**	$ 10,436	$ 9,940	$ 8,154	$ 7,644
Net earnings	**1,173**	**1,238**	1,416	1,377	3,751	3,765
Dividends on common shares	**(1,020)**	**(1,020)**	(1,020)	(1,020)	(1,469)	(1,469)
Retained earnings, end of year	**$ 10,985**	**$ 10,515**	$ 10,832	$ 10,297	$ 10,436	$ 9,940
Accumulated other comprehensive income, beginning of year	**$ (4)**	**$ (34)**	$ 359	$ 336	$ (77)	$ (113)
Derivatives designated as cash flow hedges, net of tax	**6**	**6**	2	2	(6)	(6)
Cumulative foreign currency translation	**(119)**	**(119)**	(469)	(469)	607	607
Hedge of net investment, net of tax	**51**	**51**	104	104	(165)	(165)
Pension obligation [g]	**-**	**(9)**	-	(7)	-	13
Accumulated other comprehensive income, end of year	**$ (66)**	**$ (105)**	$ (4)	$ (34)	$ 359	$ 336

Condensed Consolidated Statements of Earnings and Comprehensive Income						
	2010		2009		2008	
($ millions)	**Canadian GAAP**	**U.S. GAAP**	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Sales and operating revenues [c]	**$18,178**	**$ 17,326**	$ 15,074	$ 13,792	$ 24,701	$ 21,967
Costs and expenses (excluding depletion, depreciation and amortization) [c] [d]	**14,286**	**13,376**	11,070	9,826	17,523	14,791
Accretion expense	**53**	**53**	48	48	54	54
Depletion, depreciation and amortization [a]	**2,073**	**2,041**	1,805	1,822	1,832	1,810
Interest - net	**208**	**208**	194	194	147	147
Earnings before income taxes	**1,558**	**1,648**	1,957	1,902	5,145	5,165
Income taxes [a] [d]	**385**	**410**	541	525	1,394	1,400
Net earnings	**1,173**	**1,238**	1,416	1,377	3,751	3,765
Other comprehensive income [g]	**(62)**	**(71)**	(363)	(370)	436	449
Comprehensive income	**$ 1,111**	**$ 1,167**	$ 1,053	$ 1,007	$ 4,187	$ 4,214

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

(a) Under Canadian GAAP the ceiling test is performed by comparing the carrying value of the cost centre based on the sum of the undiscounted cash flows expected of proved reserves from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach of proved plus probable reserves using future prices. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount factor of 10%. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end or twelve-month average of the first day of each month ("twelve-month average") commencing December 31, 2009.

At December 31, 2001, the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax. As a result, for the year ended December 31, 2010, depletion expense for U.S. GAAP was reduced by $30 million (2009 - $35 million; 2008 - $44 million), before tax of $8 million (2009 - $10 million; 2008 - $13 million).

The different prices used in reserve determination under U.S GAAP and Canadian GAAP result in a lower reserve base for U.S. GAAP. Due to the lower reserve base, additional depletion of $39 million, net of tax of $14 million, was recorded under U.S. GAAP in December 2004. As of the first quarter of 2005 these reserves became economical again. In 2008, the different prices resulted in a lower reserve base for U.S. GAAP and additional depletion of $25 million, net of tax of $8 million was recorded in 2008. In 2009, additional depletion of $57 million, before tax of $17 million was recorded due to a lower U.S. GAAP reserve base. As a result of additional depletion recorded in 2004, 2008 and 2009 for lower U.S. GAAP reserve base, depletion expense was reduced by $11 million in 2010 (2009 - $5 million; 2008 - $3 million), before tax of $3 million (2009 - $2 million; 2008 - $1 million).

In 2010, additional depletion of $9 million (2009 - $57 million), before tax of $2 million (2009 - $17 million) was recorded due to a lower U.S. GAAP reserve base at December 31, 2010.

(b) Under Canadian GAAP requirements, unamortized debt issue costs are offset against the related long-term debt. Under U.S. GAAP, debt issue costs are deferred in other assets. At December 31, 2010, $26 million (2009 - $26 million; 2008 - $18 million) was reclassified from long term-debt to other assets for U.S. GAAP purposes.

(c) Under U.S. GAAP, the realized and unrealized gains and losses on natural gas purchase and sale contracts are recorded on a net basis against sales and operating expenses. Under Canadian GAAP, these gains and losses are recorded on a gross basis. For the year ended December 31, 2010, $852 million (2009 - $1,282; 2008 - $1,725) was netted against sales and operating expenses.

(d) Under FASB ASC 718, all share-based payment plans must be valued using option-pricing models. Under Canadian GAAP, the liability is measured based on the intrinsic value of the option. Over the life of the option the amount of compensation expense recognized will differ under U.S. and Canadian GAAP, creating a temporary GAAP timing difference. At exercise or surrender of the option, the compensation expense to be recorded will be equal to the cash payment, which will be identical under U.S. and Canadian GAAP and there will no longer be a GAAP difference.

At December 31, 2010 the Company has recorded an inception to date increase to current liabilities of $11 million (2009 - $23 million; 2008 - $28 million) and an inception to date increase to other long-term liabilities of $7 million (2009 - $8 million; 2008 - $11 million) based on the fair value of options and PSUs outstanding and vested. For the year ended December 31, 2010, the Company recorded a decrease to current liabilities of $12 million (2009 - decrease of $5 million;

2008 - increase of $11 million) and a decrease to other long-term liabilities of $1 million (2009 - decrease of $2 million; 2008 - decrease of $9 million) for U.S GAAP reported amounts of $2,332 million and $2,862 million, respectively. The Company also recorded an increase to net earnings of $13 million (2009 - increase of $7 million; 2008 - decrease of $2 million), before tax of $3 million (2009 - $2 million; 2008 - less than $1 million).

Under FASB ASC 718 and 505, the Company is using the Black-Scholes option pricing model to estimate the fair value of the liability related to the options and PSUs issued under the Company's tandem plan. The assumptions used in calculating fair value were:

	2010	2009	2008
Initial expected life *(years)*	**3.6**	3.5	3.3
Expected annual dividend per share	**$ 1.20**	$ 1.20	$ 2.00
Range of expected volatilities used *(%)*	**14.5 – 38.2**	19.7 – 48.4	35.3 - 73.6
Weighted-average expected volatility *(%)*	**28.6**	38.7	42.1
Range of risk-free interest rates used *(%)*	**0.0 – 2.4**	0.1 – 1.9	0.7 – 1.3

At December 31, 2010, the total intrinsic value of options exercised during the year was less than $1 million (2009 - $10 million; 2008 - $12 million), the share-based liability paid for the year was less than $1 million (2009 - $14 million; 2008 - $101 million). The total fair value of options vested during the year was $22 million (2009 - $20 million; 2008 - $32 million) and the weighted-average grant-date fair value of options granted during the year was $4.93 (2009 - $5.64; 2008 - $4.19).

The weighted average remaining contractual term of options fully vested and currently exercisable is 1.5 years (2009 – 2.5 years; 2008 – 2.9 years). The aggregate intrinsic value of options fully vested and currently exercisable is nil (2009 - $1 million; 2008 - $24 million) and the aggregate intrinsic value of options fully vested and expected to vest is nil (2009 - $1 million; 2008 - $24 million). The unrecognized compensation cost for 2010 related to non-vested awards is $24 million (2009 - $12 million; 2008 - $17 million) and the weighted average period that these costs will be recognized over is 1.61 years (2009 – 1.38 years; 2008 - 1.3 years).

(e) As a result of the reorganization of the capital structure which occurred in 2000, the deficit of Husky Oil Limited of $160 million was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(f) Until 1997 the Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(g) FASB ASC 715, "Compensation-Retirement Benefits" requires the Company to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability. The funded status is measured as the difference between the fair value of a plan's assets and its benefit obligations. Changes in this funded status are recognized through comprehensive income in the year in which the change occurs. The additional minimum liability previously recorded under the former authoritative guidance has been eliminated.

At December 31, 2010, the inception to date increase to current liabilities was $12 million to $12 million (2009 - $11 million; 2008 - $10 million) and other long-term liabilities increased by $11 million to $105 million (2009 - $90 million; 2008 - $79 million). For the year ended December 31, 2010, the Company recorded an increase to current liabilities of $0 (2009 - $0, 2008 - $0) and an increase to other long-term liabilities of $9 million (2009 – increase of $7 million, 2008 – decrease of $13 million). Other comprehensive income decreased by $12 million (2009 - decrease of $9 million; 2008 - increase of $20 million), before tax of $3 million (2009 - $2 million; 2008 - $7 million). The long term return on the plan assets in the Defined Benefit Plan for Canada was 7% (2009 - 7%; 2008 - 7%).

(h) Under Canadian GAAP, natural gas inventory held in storage is recorded at its fair value. Under U.S. GAAP, inventory is recorded at the lower of cost or market. At December 31, 2010, for U.S. GAAP purposes, the Company recorded no change to current assets (2009 - decrease of $45 million, 2008 - nil). The Company also recorded an increase to net earnings of $45 million (2009 - decrease of $45 million, 2008 - nil), before tax of $13 million (2009 - $13 million, 2008 - nil) due to the 2009 adjustment being reversed in 2010.

(i) Accounting for Uncertainty in Income Taxes establishes a two-step process for the evaluation of a tax position taken or expected to be taken in a tax return. The first step recognizes whether or not a tax position is sustainable based on a "more-likely-than-not" determination. If the tax position meets the more-likely-than-not threshold, the second step measures the amount of tax benefit to recognize in the financial statements. The tax position is measured as the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. No adjustment is required to the Company's tax provision recorded under Canadian GAAP.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2010	2009	2008
Balance at January 1	**$ 83**	$ 78	$ 30
Gross increases – prior period tax positions	**35**	10	3
Gross decreases – prior period tax positions	**(23)**	(5)	-
Additions based on tax positions related to the current year	**-**	-	50
Settlements	**-**	-	(5)
Balance at December 31, 2010	**$ 95**	$ 83	$ 78

Total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $95 million. The Company does not expect any significant changes to its unrecognized tax benefits within the next 12 month period at this time. Realization of the future income tax assets is dependent on generating sufficient taxable income during the period in which the temporary differences are deductible. Although realization is not assured, management believes that it is more likely than not that the all future income tax assets will be realized. The Company can also be affected by certain trends, events and transactions that could impact future level of taxable income. These include but are not limited to competition, economic conditions, contingencies, and the capital market.

The following are the tax years which remain subject to examination by major tax jurisdictions:

Tax Years	Jurisdiction
2000 – 2010	Federal – Canada Revenue Agency (Alberta and Ontario)
2000 – 2010	Internal Revenue Service – United States

(j) Under Canadian GAAP, inventory is recognized when the risks and rewards of ownership have passed to the Company. Under U.S. GAAP, inventory recognition is not permitted until legal title has passed to the Company. The Company has certain in transit inventory where the Company has risk and rewards of ownership, however, legal title to the inventory does not transfer to the Company until the inventory reaches the refinery gate. At December 31, 2010, for U.S. GAAP purposes, the Company derecognized in transit inventory and accounts payable of $185 million.

Additional U.S. GAAP Disclosures

Depletion, Depreciation and Amortization

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

	2010	2009	2008
Depletion, depreciation and amortization per boe	**$ 14.69**	$ 12.64	$ 11.39

Employee Future Benefits

The Company's overall investment strategy is to achieve a balance of fixed income investments. The investment objective is to achieve a long-term total rate of return equal to the long-term interest rate assumption used for going concern funding actuarial valuation.

The target allocations for plan assets are 60 percent equity securities, 35 percent in fixed income investments, and 5 percent to all other types of investments. Equity securities primarily include investments in large-cap and mid-cap companies primarily located in North America. Fixed income securities include corporate bonds of companies from diversified industries, mortgage-backed securities, and Canadian treasuries. Other types of investments include investments in cash and cash equivalents. Over complete market cycles the allocation is expected to approximate the target allocations.

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The fair values of the Company's plan assets at December 31, 2010 by asset category are as follows:

	Total	Level 1 Quoted prices in active markets	Level 2 Significant Observable Inputs	Level 3 Significant Unobservable Inputs
Canadian Equities	$ 50	$ 50	$ -	$ -
International Mutual Funds	27	-	27	-
Canada Government Bonds	17	-	17	-
Canada Fixed Income Mutual Funds	8	-	8	-
International Fixed Income	31	-	31	-
Cash and Net Receivables	1	1	-	-
Total balance at December 31, 2010	$ 134	$ 51	$ 83	$ -

The measurement date of the plan assets and the accrued benefit obligation was December 31, 2010. The most recent actuarial valuation of the Canadian defined benefit plan was December 31, 2009 and the next actuarial valuation is scheduled to occur no later than December 31, 2012. The measurement date of the plan assets and the accrued benefit obligation for the U.S. defined benefit plan was December 31, 2010. The most recent actuarial valuation of the plan was January 1, 2010 and the next actuarial valuation is scheduled to occur no later than January 1, 2011.

Plan assets are valued at the year-end quoted market prices where available. Where quoted prices are not available, estimated fair values are calculated using comparable securities.

Business Combinations

Throughout 2010, the Company completed several acquisitions of certain oil and gas properties located in key areas such as Southern Alberta and Saskatchewan for an aggregate purchase price of $399 million (2009 - $214 million, 2008 - n/a). The acquisitions were accounted for under the acquisition method of accounting in accordance with the revision of FASB ASC 805, "Business Combinations (Revised 2007)" effective January 1, 2009. Accordingly, the Company conducted individual assessments of oil and gas properties acquired and recognized provisional amounts for identifiable assets acquired at their estimated acquisition date fair values, while transaction and integration costs of less than $1 million (2009 - less than $1 million, 2008 - n/a) associated with the acquisitions are expensed as incurred. The net assets acquired were recorded at fair value in property, plant, and equipment totalling $399 million (2009 - $214 million, 2008 - n/a).

Income Tax

As at December 31, 2010, the Company had available tax loss carryforwards in the U.S. jurisdiction of $601 million expiring in 2028, $67 million expiring in 2029, and $155 million expiring in 2030.

Changes in Accounting Policies

Fair Value Measurements

On January 1, 2010, the Company prospectively adopted FASB Accounting Standards Update ("ASU") 2010-06, "Fair Value Measurements (Topic 820) Improving Disclosures about Fair Value Measurements." This update requires additional disclosures for transfers in fair value measurements between Level 1 and Level 2 within the fair value hierarchy. This update also requires incremental disclosures for changes in fair value measurements within Level 3 of the fair value hierarchy. Existing disclosures are also clarified in this update regarding the level of disaggregation required for fair value measurement disclosures as well as requirements related to disclosures about inputs and valuation techniques. The adoption of this update did not impact the Company's results of operations or financial position or disclosures.

Variable Interest Entities

On January 1, 2010, the Company prospectively adopted FASB ASU 2009-17, "Consolidations (Topic 810): Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities." This update improves the guidance on how entities account for and disclose their involvement with variable interest entities ("VIEs"). This update provides further guidance on determining the primary beneficiary of a VIE that shall include the VIE in its consolidated statements. The update also requires additional disclosures on any significant changes in risk exposure due to a reporting entity's involvement with the VIE and how its involvement affects the entity's financial statements. The adoption of this update did not impact the Company's results of operations or financial position.

Subsequent Events

On June 30, 2010, the Company prospectively adopted FASB ASU 2010-09, "Subsequent Events (Topic 855): Amendments to Certain Recognition and Disclosure Requirements." This accounting update removes the requirement for SEC filers to disclose the date through which subsequent events have been evaluated by the entity. The adoption of this update did not impact the Company's results of operations or financial position.

Document D
Form 40-F

Management's Discussion and Analysis

March 8, 2011

Husky Energy Inc.

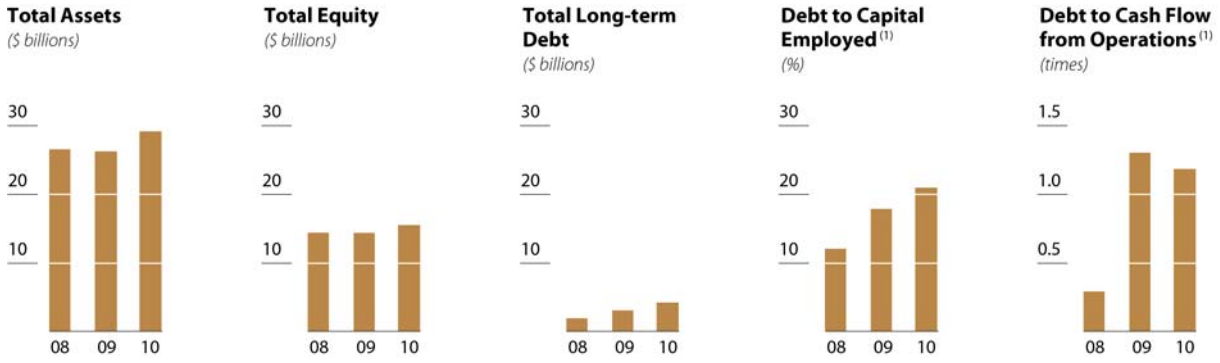
Management's Discussion and Analysis

For the Year Ended December 31, 2010
March 8, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

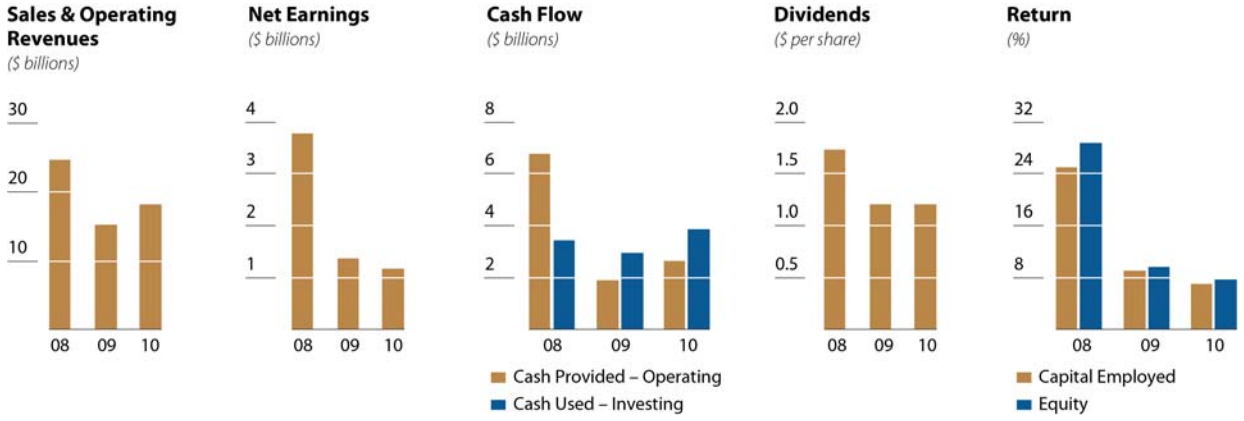
1.0 Financial Summary

1.1 Financial Position



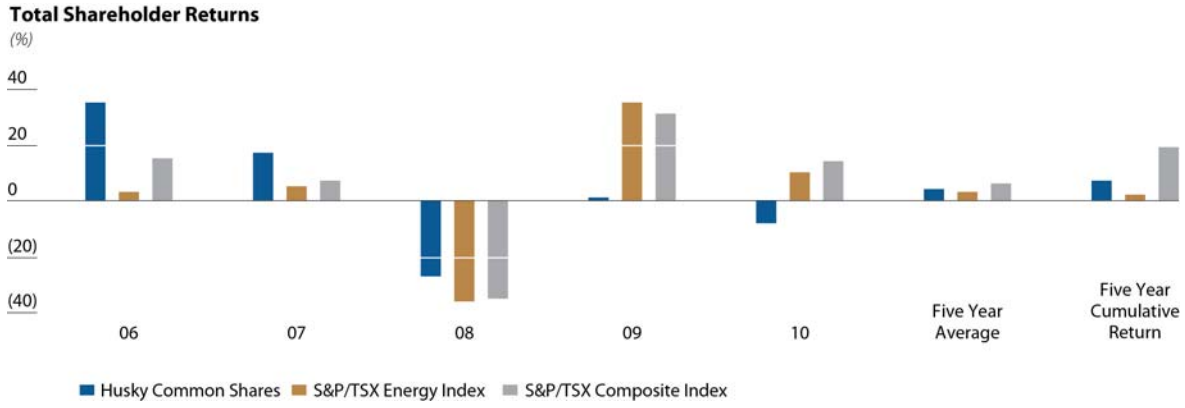
(1) *Capital employed and cash flow from operations are non-GAAP measures. (Refer to Section 11.3)*

1.2 Financial Performance



1.3 Total Shareholder Returns

The following graph shows the total shareholder returns compared with the Standard and Poor's ("S&P") and the Toronto Stock Exchange ("TSX") energy and composite indices.



1.4 Selected Annual Information

($ millions, except where indicated)	**2010**	2009	2008
Sales and operating revenues, net of royalties	**18,178**	15,074	24,701
Net earnings by sector			
Upstream	**1,135**	1,113	3,377
Midstream	**182**	254	470
Downstream	**95**	265	(299)
Corporate	**(192)**	(172)	142
Eliminations	**(47)**	(44)	61
Net earnings	**1,173**	1,416	3,751
Net earnings per share - basic/diluted	**1.38**	1.67	4.42
Ordinary dividends per common share	**1.20**	1.20	1.70
Cash flow from operations [1]	**3,549**	2,507	5,946
Total assets	**29,133**	26,295	26,486
Long-term debt including current portion	**4,187**	3,229	1,957
Cash and cash equivalents	**252**	392	913
Return on equity *(percent)*	**7.8**	9.8	28.9
Return on average capital employed [1] *(percent)*	**7.1**	9.1	25.1

[1] *Cash flow from operations and capital employed are non-GAAP measures. (Refer to Section 11.3)*

2.0 Husky Business Overview

Husky Energy is one of Canada's largest integrated energy companies. It is headquartered in Calgary, Alberta, and is publicly traded on the TSX under the symbol HSE. The Company operates worldwide with Upstream, Midstream and Downstream business segments. Husky uses a combination of technological innovation, prudent investment, sound project management and responsible resource development to deliver consistent shareholder returns.

- In the Upstream segment, the Company explores for, develops and produces crude oil and natural gas (Upstream business segment).
- In the Midstream segment, Husky upgrades heavy crude oil (upgrading business segment), processes and transports via pipeline heavy crude oil, as well as markets and operates storage facilities for crude oil and natural gas (infrastructure and marketing business segment).
- In the Downstream segment, the Company distributes motor fuel and ancillary and convenience products, manufactures and markets asphalt products, produces ethanol and operates two regional refineries in Canada (Canadian refined products business segment) and refines crude oil through interests in two refineries in Ohio and markets refined products in the U.S. Midwest (U.S. refining and marketing business segment).

3.0 The 2010 Business Environment

3.1 Business Risk Factors

Husky's results of operations are significantly influenced by the global and domestic business environment. Some risk factors are entirely beyond the Company's influence and others can, to some extent, be strategically managed. Husky has implemented appropriate risk management processes to manage these risks. Salient risk factors include:

Financial and Economic Risks

An adverse change in any of the following conditions could affect the Company's ability to realize the value and quantity of Husky's oil and natural gas reserves, achieve expected cash flow and financial performance, optimize project economics, sanction capital projects, and negatively impact the Company's results of operations, liquidity and financial condition:

- the demand for the Company's products and the prices the Company receives for crude oil and natural gas production and refined petroleum products;
- the economic conditions of the markets in which Husky conducts business;

- the exchange rate between the Canadian and U.S. dollar;
- the cost and availability of capital, including access to capital markets at acceptable rates; and
- other financial risks as described in Section 8.6.

Operational Risks

An adverse change in any of the following conditions could affect the Company's ability to gain access to the resources required to increase oil and natural gas reserves and production, retain adequate markets for its products and services, gain access to capital markets and complete development projects:

- the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions;
- the availability of prospective drilling rights;
- the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project development;
- the availability and cost of labour, material and equipment to efficiently, effectively and safely undertake capital projects;
- the costs to operate properties, plants and equipment in an efficient, reliable and safe manner;
- prevailing climatic conditions in the Company's operating locations;
- the competitive actions of other companies, including increased competition from other oil and gas companies;
- business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect Husky and that may or may not be financially recoverable;
- the inability to reach the Company's estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties or other risk factors; and
- changes in workforce demographics.

Legislative Risks

An adverse change in any of the following conditions could affect the Company's ability to access markets, utilize its financial resources in an efficient manner, undertake exploration, development and construction projects as well as impact the Company's interests in its foreign operations and future profitability:

- potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
- changes to royalty regimes;
- regulations to deal with climate change issues;
- changes to government fiscal, monetary and other financial policies; and
- the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects.

3.2 Economic Sensitivities

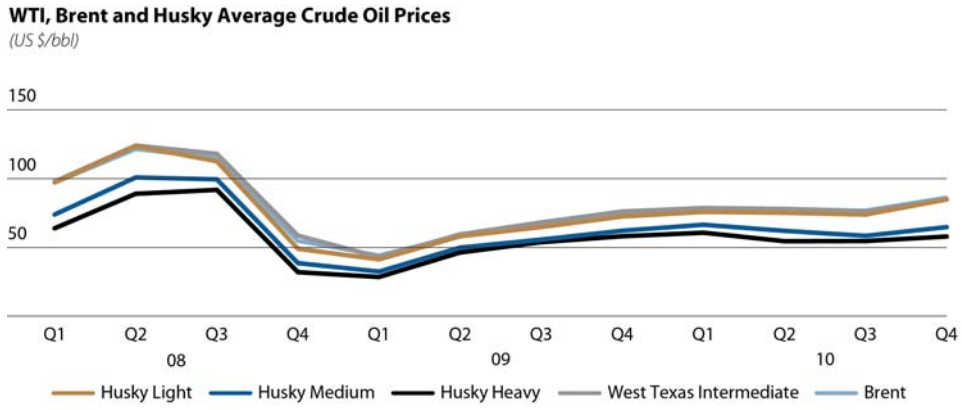
Average Benchmarks		2010	2009	2008
WTI crude oil	*(U.S. $/bbl)*	**79.46**	61.80	99.65
Brent crude oil	*(U.S. $/bbl)*	**79.42**	61.54	96.99
Canadian light crude 0.3% sulphur	*($/bbl)*	**77.75**	66.19	102.84
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**59.87**	53.60	72.44
NYMEX natural gas	*(U.S. $/mmbtu)*	**4.39**	3.99	9.04
NIT natural gas	*($/GJ)*	**3.91**	3.92	7.70
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**14.48**	9.93	20.38
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**9.64**	8.33	9.96
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**9.20**	8.43	11.17
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.971**	0.880	0.937
Canadian Equivalents				
WTI crude oil	*($/bbl)*	**81.83**	70.23	113.24
Brent crude oil	*($/bbl)*	**81.79**	69.93	110.22
WTI/Lloyd crude blend differential	*($/bbl)*	**14.91**	11.28	21.75
NYMEX natural gas	*($/mmbtu)*	**4.52**	4.53	9.65

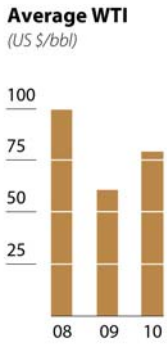
As an integrated producer, Husky's profitability is largely determined by realized prices for crude oil and natural gas and refinery processing margins including the effect of changes in the U.S./Canadian dollar exchange rate. All of Husky's crude oil production and the majority of its natural gas production receive the prevailing market price. The price for crude oil is determined largely by global factors and is beyond the Company's control. The price for natural gas is determined more by the North America

fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. Weather conditions also exert a dramatic effect on short-term supply and demand.

The Midstream and Downstream segments are also heavily impacted by the price of crude oil and natural gas. The largest cost factor in the midstream - upgrading business segment is the heavy crude oil feedstock, which is processed into light synthetic crude oil. The largest cost factors in the Downstream segment are crude oil feedstock and processing costs. Husky's U.S. refining operations process a mix of different types of crude oil from various sources but are primarily light sweet crude oil at the Lima, Ohio Refinery and approximately 50% heavy crude oil feedstock at the Toledo, Ohio Refinery. The Company's refined products business in Canada relies primarily on purchased refined products for resale in the retail distribution network. Refined products are acquired from other Canadian refiners at rack prices or exchanged with production from the Husky Prince George Refinery.

Crude Oil

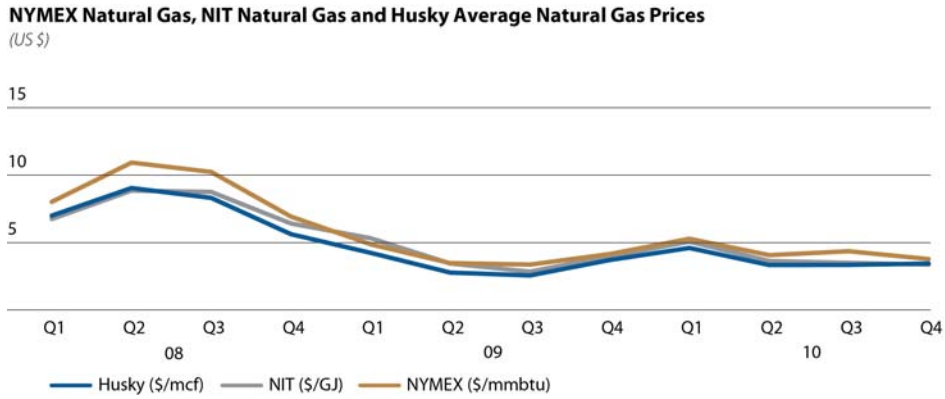


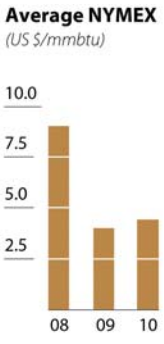


The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production in the Atlantic Region and offshore South East Asia is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2010 at U.S. $91.38/bbl recovering from U.S. $79.36/bbl on December 31, 2009, and averaged U.S. $79.46/bbl in 2010 compared with U.S. $61.80/bbl in 2009. The price of Brent ended 2010 at U.S. $92.55/bbl, recovering from U.S. $77.67/bbl on December 31, 2009, and averaged U.S. $79.42/bbl in 2010 compared with U.S. $61.54/bbl in 2009.

A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2010, 48% of Husky's crude oil production was heavy crude oil or bitumen compared with 47% in 2009. The light/heavy crude oil differential averaged U.S. $14.48/bbl or 18% of WTI in 2010 increasing from U.S. $9.93/bbl or 16% of WTI in 2009.

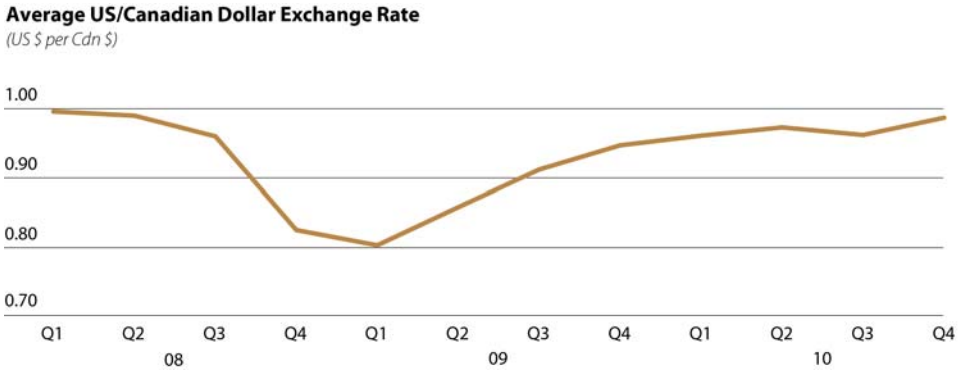
Natural Gas

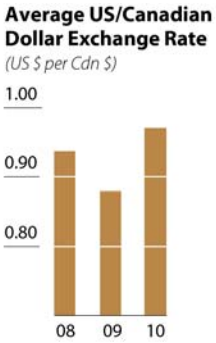




In 2010, 29% of Husky's total oil and gas production was natural gas. The near-month natural gas price quoted on the NYMEX ended 2010 at U.S. $4.41/mmbtu compared with U.S. $5.57/mmbtu at December 31, 2009. During 2010, the NYMEX near-month contract price of natural gas averaged U.S. $4.39/mmbtu compared with U.S. $3.99/mmbtu in 2009.

Foreign Exchange





The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the revenues received from the sale of oil and gas commodities. Correspondingly, an increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. The majority of the Company's long-term debt is denominated in U.S. dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the principal amount owing of the long-term debt at maturity and the associated interest payments.

The Canadian dollar ended 2009 at U.S. $0.956 and subsequently strengthened during 2010, closing at U.S. $1.005 at December 31, 2010. In 2010, the Canadian dollar averaged U.S. $0.971 strengthening by 10% compared with U.S. $0.880 during 2009.

Increased U.S. crude oil prices were partially offset by the significant strengthening of the Canadian dollar against the U.S. dollar in 2010. The price of WTI in 2010 in U.S. dollars increased 29% compared with an increase of 17% in Canadian dollars when compared to 2009.

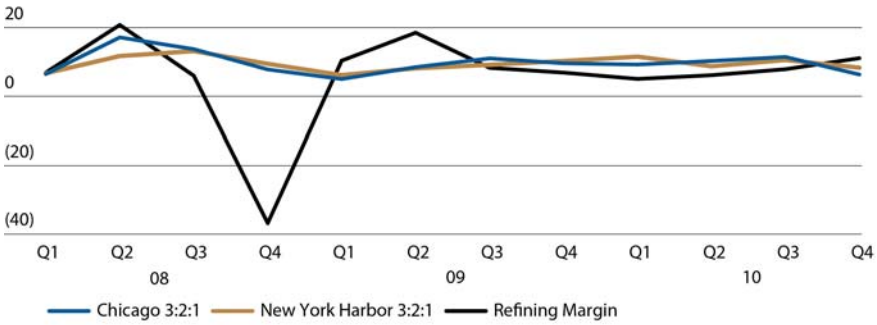
Refining Crack Spreads

The 3:2:1 refining crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and do not necessarily reflect the actual crude purchase costs or product configuration of a specific refinery. Each refinery has a unique crack spread depending on several variables. Realized refining margins are affected by the product configuration of each refinery and by the time lag between the purchase and delivery of crude oil feedstock which is accounted for on a first in first out ("FIFO") basis in accordance with Canadian Generally Accepted Accounting Principles ("GAAP").

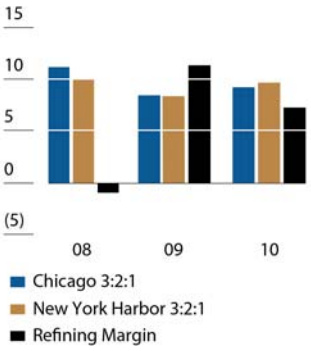
The New York Harbor 3:2:1 refining crack spread benchmark is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two-thirds of a barrel of reformulated gasoline and the price of one-third of a barrel of heating oil. The Chicago 3:2:1 refining crack spread benchmark is calculated based on WTI, regular unleaded gasoline and ultra low sulphur diesel. During 2010, the New York Harbor 3:2:1 refining crack spread averaged U.S. $9.64/bbl compared with U.S. $8.33/bbl in 2009. During 2010, the Chicago 3:2:1 crack spread averaged U.S. $9.20/bbl compared with U.S. $8.43/bbl in 2009.

During 2010, the 3:2:1 crack spreads were higher than 2009 reflecting the recovering U.S. economic environment which has resulted in increased demand for transportation fuel, lower inventory and stronger margins.

Chicago and New York Harbor Average Crack Spread and Husky Realized U.S. Refining Margin
(US $/bbl)



Average Crack Spread
(US $/bbl)



Cost Environment

From 2003 to 2008, the oil and gas industry experienced increasing costs that rose above the general trend of inflation. This resulted when the high level of industry activity, precipitated by escalating oil and gas prices, created demand for goods and services that exceeded supply. This increased the cost of operating the Company's oil and gas properties, processing plants and refineries. As a result of the global economic and financial crisis, the level of drilling and completions in the Western Canada Sedimentary Basin was significantly reduced in 2009, recovering in respect of oil well completions in 2010 while low natural gas prices continued to depress gas well completions. In addition, prospective capital projects including oil sands developments and major plant modifications were deferred pending cost improvements. Oil and gas prices declined rapidly in the latter half of 2008 and the first quarter of 2009, however, a corresponding decline in costs was delayed until the latter half of 2009. Crude oil prices have since recovered to the U.S. $90/bbl to U.S. $100/bbl range and industry activity, both drilling and field services, is increasing. The cost of field services is beginning to rise with higher demand, particularly in new technology driven plays.

Enbridge Line 6A/6B Shutdowns

During the third quarter of 2010, a crude oil release occurred on both Line 6A near Romeoville, Illinois and Line 6B near Marshall, Michigan. The pipelines in those vicinities were shut down until appropriate repairs were made. Line 6A was shut down on September 9 and returned to service on September 17. Line 6B was shut down on July 26 and resumed service on September 27. Since resuming service, Line 6B has continued to operate at less than full capacity.

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted medium and heavy crude oil and bitumen realized prices in the Upstream business segment. The shutdowns also reduced throughput at the Toledo Refinery in the third quarter of 2010 due to limited heavy crude oil availability and increased feedstock costs as heavy oil was partially replaced with light oil where available. In the fourth quarter, the widened differential resulted in lower feedstock costs which benefited the Midstream and Downstream segments as unit margins increased for the Lloydminster Upgrader and Lloydminster and Toledo Refineries, which partially offset the negatively impacted medium and heavy crude oil and bitumen realized prices in Upstream. The shutdowns also increased Husky's inventory volumes at the end of the year as the Company increased storage volumes to mitigate the impact of selling medium and heavy crude oil and bitumen at distressed prices to third parties as a result of the widened differential. The result of the Enbridge Line 6A/6B shutdowns was an approximate $53 million reduction to Husky's net earnings ($60 million reduction in Upstream, $10 million increase in Midstream, $3 million reduction in Downstream) in 2010.

Global Economic and Financial Environment

During 2010 WTI spot prices fluctuated between U.S. $91.50/bbl and U.S. $64.80/bbl and in the first two months of 2011 averaged U.S. $89.44/bbl. In the February 8, 2011 Short-term Energy Outlook[1] the Energy Information Administration ("EIA") indicated that it expects markets for crude oil and liquid fuels to tighten over the next two years. The EIA expects world oil consumption to grow an average of 1.5 mmbbls/day through 2012 and for supply from non-Organization of the Petroleum Exporting Countries ("non-OPEC") to increase marginally. As a result the market will need to draw on inventories and increased supply from OPEC. OPEC spare productive capacity averaged an estimated 4.7 mmbbls/day during 2010 and is expected to average 4.7 mmbbls/day in 2011 and 4.2 mmbbls/day in 2012. OPEC liquid fuel supply, which is not subject to OPEC's production policy, is expected to add marginally to total OPEC supply through 2012. At its meeting on December 11, 2010, OPEC agreed to maintain its current production policy and is scheduled to meet again on June 2, 2011. The EIA estimates that Organization for Economic Cooperation and Development ("OECD") countries held 2.7 billion barrels of commercial oil inventories at the end of 2010. This represents approximately 57 days of forward cover. The EIA expects OECD oil inventories to remain close to the middle of the past five year range throughout the forecast period, ending 2012 with 55 days of forward cover.

In the EIA's February 8, 2011 Short-term Energy Outlook, natural gas consumption in U.S. markets is expected to remain flat through 2012. Higher consumption in the industrial and electrical generation sectors is mostly offset by expected reductions in the residential and commercial sectors. Natural gas production in the U.S. is expected to level off in the near term, increasing by 2% from 2010 to 2012. Imports of both pipeline natural gas and liquefied natural gas into the United States are expected to decline over the forecast period. In its Weekly Natural Gas Storage Report[2] released February 3, 2011, the EIA reported that natural gas stocks were equal to the five year average and 2.8% below the previous year. The EIA expects continued natural gas price volatility in the near term.

There are a number of uncertainties that could result in higher or lower commodity prices. They include decisions made by OPEC regarding their production levels, the rate of global and U.S. economic recovery, the response by governments to various fiscal issues, the effect of China's efforts to address its growth and inflation and the general political stability of certain key strategic areas in the world.

Additionally, recent developments in Egypt, Libya and other North African and Middle East countries add uncertainty to oil and natural gas supply and demand. The Company closely monitors the developments in these areas.

Note:

(1) *Energy Information Administration, Short-Term Energy Outlook DOE/EIA – February 8, 2011 Release.*
(2) *"Weekly Natural Gas Storage Report", February 3, 2011, Energy Information Administration, U.S. Department of Energy.*

3.3 Sensitivities by Segment for 2010 Results

The following table is indicative of the relative annualized effect on pre-tax cash flow and net earnings from changes in certain key variables in 2010. The table below shows what the effect would have been on 2010 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2010. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis

	2010 Average	Increase	Effect on Pre-tax Cash Flow [5]		Effect on Net Earnings [5]	
			($ millions)	*($/share)* [6]	*($ millions)*	*($/share)* [6]
Upstream and Midstream						
WTI benchmark crude oil price [1]	$ 79.46	*U.S. $1.00/bbl*	62	0.07	45	0.05
NYMEX benchmark natural gas price [2]	$ 4.39	*U.S. $0.20/mmbtu*	25	0.03	18	0.02
WTI/Lloyd crude blend differential [3]	$ 14.48	*U.S. $1.00/bbl*	(10)	(0.01)	(9)	(0.01)
Downstream						
Canadian light oil margins	$ 0.029	*Cdn $0.005/litre*	14	0.02	10	0.01
Asphalt margins	$ 15.74	*Cdn $1.00/bbl*	8	0.01	6	0.01
New York Harbor 3:2:1 crack spread [4]	$ 9.64	*U.S. $1.00/bbl*	79	0.09	49	0.06
Consolidated						
Exchange rate (U.S. $ per Cdn $) [1]	$ 0.971	*U.S. $0.01*	(51)	(0.06)	(38)	(0.04)
Interest rate		*100 basis points*	(10)	(0.01)	(8)	(0.01)

(1) *Does not include gains or losses on inventory.*
(2) *Includes decrease in earnings related to natural gas consumption.*
(3) *Excludes impact on asphalt operations.*
(4) *Relates to U.S. Refining & Marketing.*
(5) *Excludes mark to market accounting impacts.*
(6) *Based on 890.7 million common shares outstanding as of December 31, 2010.*

4.0 Capability to Deliver Results

Husky's results are dependent on a number of factors including commodity prices, foreign exchange rates, interest rates, the Company's continued success in exploring for oil and natural gas, efficient and safe execution of capital projects and operations, effective marketing of crude oil and natural gas, retention of expertise and continued access to the financial markets.

4.1 Upstream

- Large base of crude oil producing properties in Western Canada that continues to produce with existing technology and has responded well to the application of increasingly sophisticated exploitation techniques such as horizontal drilling. Enhanced oil recovery ("EOR") techniques including thermal in-situ recovery methods are extensively used in the mature Western Canada Sedimentary Basin to increase recovery rates and stabilize decline rates of heavy and light crude oil. Emerging EOR techniques are being field tested, while techniques that have been in practice for several decades continue to be optimized;
- Substantial position in the Alberta oil sands. The initial stages of the development of these assets include the Tucker oil sands project currently in production and the Sunrise Energy Project that is in the development phase. The Sunrise Energy Project is proceeding as a joint 50/50 partnership with BP and is an integral part of a North American oil sands business that includes the BP-Husky Toledo Refinery;
- Harsh weather offshore exploration, development and production expertise, as demonstrated by the successful White Rose development and further development of the North Amethyst and West White Rose satellite fields offshore Newfoundland. Husky also holds an interest in the Terra Nova field and a large portfolio of significant discovery and exploration licences offshore Newfoundland and Labrador and offshore Greenland (collectively referred to as "Atlantic Region");
- A growing position in Western Canada gas resource plays with approximately 800,000 acres associated with both liquid rich and dry gas positions;
- A growing oil resource play position with existing activities in the Viking, Bakken, Lower Shaunavon, and Cardium formations;
- Expertise and experience exploring and developing the high impact natural gas potential in the Alberta Deep Basin, foothills, and northwest plains of Alberta and British Columbia;
- Position offshore China that includes a production interest in the Wenchang oil field, significant natural gas discoveries at the Liwan 3-1 and Liuhua 34-2 fields in Block 29/26 where development has commenced, significant natural gas discovery at the Liuhua 29-1 field within Block 29/26, and a Production Sharing Contract ("PSC") in Block 63/05; and
- Offshore Indonesia where Husky holds two exploration licences. The Madura BD natural gas and natural gas liquids discovery, in which the Company holds a 40% interest, is the current focus for development.

4.2 Midstream

- Heavy oil upgrading facility located in the Lloydminster, Saskatchewan heavy oil producing region with a throughput capacity of 82 mbbls/day;
- Integrated heavy oil pipeline systems in the Lloydminster producing region;
- Natural gas storage in excess of 50 bcf, owned and leased;
- Petroleum marketer balancing the needs of both customers and suppliers; and
- Supplier of crude oil, natural gas, petroleum coke, sulphur and electrical power for the Company's plants and facilities.

4.3 Downstream

- Refinery at Lima, Ohio, and a 50% interest in the BP-Husky Refinery in Toledo, Ohio each with a gross crude oil throughput capacity of 160 mbbls/day;
- Refinery at Prince George, British Columbia with throughput of 12 mbbls/day producing low sulphur gasoline and ultra low sulphur diesel;
- Largest marketer of paving asphalt in Western Canada with a 29 mbbls/day capacity asphalt refinery located at Lloydminster, Alberta integrated with the local heavy oil production, transportation and upgrading infrastructure;
- Largest producer of ethanol in Western Canada with a combined 260 million litre per year capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba; and
- Major regional motor fuel marketer with 555 retail marketing locations including bulk plants and travel centres with strategic land positions in Western Canada and Ontario. Retail outlets include, in many cases, convenience stores, restaurants, service bays and carwashes. At the end of 2010, Husky completed the rebranding of 98 sites in Eastern Canada acquired in late 2009.

4.4 Corporate

Husky's corporate capabilities are discussed in the following sections:

- Section 8.0 Liquidity and Capital Resources
- Section 11.5 Disclosure Controls and Procedures

5.0 Strategic Plan

Husky's current strategy is to continue to exploit oil and gas assets in Western Canada, while advancing its three major growth pillars in the Oil Sands, the Atlantic Region and South East Asia. Husky is an integrated company in a specialized sense. The Company is not integrated on a barrel-for-barrel basis and seeks to operate and maintain Midstream and Downstream assets which provide specialized support and value to its Upstream assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

Husky's strategic direction by business segment is as follows:

5.1 Upstream

Husky's current strategy is to continue to exploit oil and gas assets in Western Canada, while advancing its three major growth pillars in the Oil Sands, the Atlantic Region and South East Asia.

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometres in northern Alberta. The Company took a significant step toward unlocking the potential of this vast resource in 2010 with the sanctioning of Phase I of the Sunrise Energy Project. Husky will focus on Sunrise, which is a premier, in-situ oil sands development and represents a transformational opportunity for the Company. The first phase, representing an investment of $2.5 billion, is expected to produce about 60,000 barrels per day beginning in 2014. Husky's working interest is 50%. Sunrise will use proven steam-assisted gravity drainage ("SAGD") technology, keeping site disturbance to a minimum.

The Atlantic Region stretches from Greenland to the Sydney Basin, south of Newfoundland. North Amethyst was brought on production in May 2010 and is expected to reach its peak production rate in 2011 as more wells are drilled and brought into production. In 2010, Husky received approval for a two-well pilot project at its next satellite development, West White Rose. Production is expected to come on stream in mid-2011. The Atlantic Region continues to represent a growth opportunity, with the Company holding 19 Exploration Licences and interests in six Production Licences and 23 Significant Discovery Areas. Work is well under way to identify new and innovative ways to further develop the significant resources in the basin.

Husky made an important decision in 2010 to retain its assets in South East Asia in order to continue to build a material oil and natural gas business in this resource-rich region. The Company is moving forward with plans to develop the Liwan 3-1 natural gas project on Block 29/26 in the South China Sea. The Liwan 3-1 field, located approximately 300 kilometres southeast of Hong Kong, is an important component of the Company's mid-term production growth strategy and a key step in accessing the burgeoning energy markets in Hong Kong and Mainland China. Husky has partnered with China National Offshore Oil Corporation ("CNOOC") on the development and first gas production is anticipated in late 2013. Combined with the producing Wenchang oil field, further natural gas discoveries on Block 29/26, and growth opportunities in Indonesia including the extension of the Madura Strait PSC, South East Asia represents a strong growth engine for Husky.

5.2 Midstream

Husky's strategic plan for Midstream is focused on supporting heavy oil and oil sands production and making prudent reinvestment. Husky is not planning major expansions in 2011. The Company's spending will be focused on maintenance and optimizing existing infrastructure.

5.3 Downstream

Husky's strategic plan for Downstream is focused on supporting heavy oil and oil sands production and making prudent reinvestments. Husky will continue to pursue projects to optimize, integrate and reconfigure the Lima, Ohio Refinery for heavy crude oil feedstock and is planning to reconfigure and expand the BP-Husky Toledo, Ohio Refinery to accommodate Sunrise production as its primary feedstock. The Company will also expand terminalling and product storage opportunities.

5.4 Financial

Husky is committed to ensuring adequate liquidity and financial flexibility to fund the Company's growth and support dividend payments. Over the business cycle, the Company's objective is to maintain a debt to cash flow from operations ratio of less than 2.5 times and a debt to capital employed target of 25% to 35%.

The Company also aims to retain investment grade credit ratings. The Company continues to focus on the existing financial discipline around costs and the efficiency of Husky's operations and, at the same time, emphasizing the Company's focus on its return on capital.

6.0 Key Growth Highlights

The 2010 capital program was established with a view of maintaining Husky's balance sheet and taking advantage of opportunities as economic conditions improved and financial uncertainty abated. Capital expenditures continued to focus on those projects offering the highest potential for returns and mid to long-term growth. During 2010, as a result of an ongoing comprehensive review of the Company's operations and business strategies, Husky increased its capital program and redirected a portion of it to focus on delivering near-term production growth. Husky's 2011 capital program has been established with a view of enabling the Company to build on the momentum achieved in 2010 with respect to accelerating near-term production growth as well as continuing to advance its three major growth pillars in the Oil Sands, the Atlantic Region and South East Asia.

6.1 Upstream

Atlantic Region

White Rose Development Projects

Drilling in the North Amethyst satellite subsea tie-back project continued in early 2010 with the use of the *GSF Grand Banks* drilling rig. First production was achieved on May 31, 2010 with one production well and a water injection well, while a second production well was completed in September 2010 and a second water injector completed and came on production in January 2011. Production is tied back to the existing *SeaRose FPSO* infrastructure. A total of 11 wells are planned for North Amethyst, including 2 to 3 wells in 2011.

Husky continues to progress plans for a staged development of the West White Rose field. In August 2010, the Company received regulatory approval for a 2-well pilot project to be drilled from the existing infrastructure at the White Rose field. The E-18-10 production well was drilled to total depth in 2010 and will be completed in 2011. These wells will provide additional information on the reservoir to refine development plans for the full West White Rose field. A production licence was received in the fourth quarter of 2010, and first production is anticipated mid-2011.

Exploration

Husky continues to evaluate its exploration opportunities offshore Newfoundland and Labrador and in January 2010 spudded the Glenwood H-69 exploration well northwest of the White Rose field. The well was suspended in March 2010 and the well data continues to be evaluated.

Husky, along with Suncor and Statoil Canada announced plans to enter into a second rig sharing agreement for the mobile semi-submersible drilling rig *Henry Goodrich*. The agreement will keep the rig in the Atlantic Region until November 2013. Husky intends to use its portion of rig time to pursue a combination of exploration, appraisal and development drilling opportunities.

In 2010, Husky completed a 3,000 kilometre 2-dimensional ("2-D") seismic acquisition survey in the Sydney Basin between Newfoundland and Nova Scotia. Husky also acquired over 2,500 kilometres of 2-D seismic surveys on exploration acreage offshore Labrador. Exploration rights for these areas were awarded to Husky during land sales in 2008.

In February 2010, the Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") issued a significant discovery licence ("SDL") for the Mizzen prospect. In late 2010, Husky was successful in acquiring a new SDL for the Mizzen prospect and exploration rights in three additional parcels of land in the C-NLOPB November land sale. The exploration properties are adjacent to other Husky land holdings in the Jeanne d'Arc Basin and Flemish Pass. The new SDL extends the previous Mizzen SDL awarded in February 2010. An appraisal well is planned at Mizzen in the third quarter of 2011. Husky holds a 35% working interest in the Mizzen property.

The evaluation of a 7,000 kilometre 2-D seismic program acquired in the third quarter of 2008 on Blocks 5 and 7 offshore Greenland is complete. Evaluation of an airborne gravity and magnetics survey that was acquired in the second quarter of 2009 is nearing completion. In November 2009, Husky completed the acquisition of a 2,200 square kilometre 3-D seismic program over Block 5 and Block 7. This survey is the first 3-D seismic survey conducted offshore Greenland and utilizes a new dualsensor "Geostreamer" technology. Final processing of the 3-D seismic for Block 7 was completed in the fourth quarter of 2010. Final processing of Block 5 data is expected to be completed in the first quarter of 2011. Preliminary evaluation of the seismic data has identified several leads and potential drilling locations will be identified over the course of the first quarter of 2011. Husky is the operator and holds an 87.5% interest in these two blocks. Husky also holds a 43.75% working interest in Block 6 where 3,000 kilometres of 2-D seismic was acquired in the third quarter of 2008.

Heavy Oil

Construction of the 8,000 bbls/day South Pike's Peak project was approximately 49% complete at the end of 2010. Production is expected to commence in the first half of 2012. Horizontal well developments progressed through 2010, targeting new geological horizons in existing regions. A total of 101 horizontal wells were drilled in 2010.

Husky continued to operate two solvent EOR pilots through 2010 at Edam and Mervin. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction with expected completion in the third quarter of 2011. This liquefied CO_2 is to be used in the ongoing piloting program. A microbial EOR pilot in Wainwright, Alberta continued in 2010 with nine wells continuing to show a substantial response eight months after treatment. A second pilot in Devonia Lake has commenced with two cycles of treatments completed. The preliminary results show a 20% increase in oil production.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages and sanctioned Phase I in November 2010. Husky reached an agreement with Enbridge, IPF, and Keyera on the movement of diluted bitumen to market and transportation of diluent to the Sunrise oil sands site. Husky also awarded major engineering and construction contracts to Snamprogetti Canada for the central processing facilities and to Worley Parsons for the field facilities. Husky has initiated conceptual development engineering for subsequent phases and is expecting a comprehensive full field development plan to be established by the end of 2011.

Bitumen production from Phase I is planned at approximately 60 mbbls/day gross and is expected to commence in the first quarter of 2014. Regulatory approval is in place to increase total gross production to 200 mbbls/day. Husky and BP are equal partners in the Sunrise Energy Project, with Husky operating Sunrise.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by remediating older wells with innovative new stimulation techniques, drilling new wells and initiating new start up procedures. The results will be evaluated over the next six to twelve months. During 2010, Husky drilled 32 wells (16 well pairs) and is planning to drill an additional eight wells (four pairs) in 2011. Three well pairs commenced production in late September 2010 and are exceeding the performance of well pairs previously drilled. Production at Tucker for December 2010 was 6.1 mboe/day compared to 5.0 mboe/day in December 2009. Several applications to the Energy Resources Conservation Board ("ERCB") have been approved or are proceeding for additional drilling and field development through to 2015.

McMullen

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production drilling project and an air injection pilot. An additional 79 cold production wells were drilled in 2010 and up to 64 wells are scheduled for 2011. Cold production from eastern McMullen for December 2010 was 2,900 bbls/day.

Husky has submitted an application and received ERCB approval for an air injection pilot. Construction will be proceeding in the first quarter of 2011 with ignition scheduled for late in the second quarter of 2011.

Sale of Oil Sands Leases

On January 14, 2011, the Company completed an agreement to sell 23 square miles of mining leases in Alberta for a consideration of $200 million.

Western Canada and the United States (excluding Heavy Oil and Oil Sands)

Asset Acquisitions

In November 2010, Husky announced that a purchase and sale agreement had been signed with ExxonMobil Canada Ltd. to acquire oil and natural gas properties in Alberta and northeast British Columbia. The acquired assets will add 16.3 mboe/day to natural gas production, 4.8 mboe/day to oil production and 0.8 mboe/day to natural gas liquids production. Based on reserve estimates at December 1, 2010, the acquisition will contribute 104 mmboe of proved reserves and nine mmboe of probable reserves to a core producing area. The acquisition closed on February 4, 2011.

The purchase of natural gas properties in west central Alberta closed on November 30, 2010. The acquisition added 10.8 mboe/day of natural gas production, 32.6 mmboe of proved reserves and 10.8 mmboe of probable reserves to a core producing area. The reserve estimates are as at December 31, 2010.

Husky recognizes the operational results from the natural gas properties post the closing date; the operational results between the effective date and the closing date are deducted from the purchase price.

Gas Resource Plays

Husky continues to build its gas resource play inventory. In 2010, the Company acquired over 69,000 acres of additional land in several of its British Columbia and Alberta plays. At the end of 2010, the Company had a total of approximately 800,000 net acres of gas resource play inventory.

Husky is accelerating exploration and development drilling in the NGL-rich Ansell area. As part of this program, a total of 20 Cardium formation development wells were drilled and a further 14 exploration wells were drilled in 2010 to test the deeper multi-zone potential in the area. Drilling operations are continuing into 2011, with four rigs active on the property. Export capacity expansion work proceeded through 2010 with approximately 70% of the detailed engineering completed and a majority of the long lead equipment orders placed.

At Kakwa, the first well in a multi-well exploration program was spud in late December 2010. This program will test the multi-zone Cretaceous potential that targets the same formations as Husky's exploration program at Ansell. In British Columbia, a partner operated horizontal well was drilled to further evaluate the Montney formation on the Company's Cypress lands. Completion of this well occurred in the first quarter of 2011, and the well is currently being flow tested. Also, near the end of 2010, 3-D seismic programs were initiated in the Ansell, Komie (Horn River), and Sierra areas. Husky is also actively drilling development wells in the Greater Bivouac area with 11 gross (9 net) wells drilled in 2010, targeting the Jean Marie formation. One rig continues to drill in the Bivouac area in the first quarter of 2011.

Oil Resource Plays

Oil resource play evaluation and testing activity continued in Western Canada in 2010. Twenty-three Viking horizontal wells at Redwater, Alberta and 13 Viking wells in the Dodsland/Elrose area of Saskatchewan were brought into production in 2010. Three evaluation wells are currently under production testing to assess the Cardium zone at Lanaway, Alberta. In 2011, four Viking wells have been drilled in the Elrose area with three more scheduled before spring break up.

Production and evaluation of the Lower Shaunavon and Bakken zones continues in southern Saskatchewan. In the Lower Shaunavon zone, three successful horizontal wells were brought on production in 2010 with three additional wells to be drilled in the first quarter of 2011. In the Bakken zone, four successful horizontal wells were drilled with two put into production in 2010 and the two remaining wells expected to be put in production in the first quarter of 2011. Two additional Bakken wells are to be drilled in the first quarter of 2011. At the end of 2010, the Company had approximately 500,000 net acres of oil resource play inventory.

Northeastern British Columbia

Husky participated in a well in the Grizzly Valley located in the foothills of northeastern British Columbia where it has a 42% working interest. The well has been tested at a rate of 33 mmcf/day and tie-in of the well was completed in mid-January 2011. Husky successfully acquired four additional drilling licences in the Grizzly Valley area during 2010.

Alkaline Surfactant Polymer Floods

Husky's Alkaline Surfactant Polymer ("ASP") EOR Program is underway with active projects at Warner, Crowsnest in southern Alberta and Gull Lake, Saskatchewan. In addition, Husky holds a 20.3% non-operating working interest in the Instow, Saskatchewan ASP flood, in which oil response continues to increase in line with expectations. Future floods under development include Fosterton and Bone Creek, Saskatchewan. At Fosterton, the facility design work is nearing completion and long lead equipment orders have been placed. Facility construction is expected to commence in 2011 with an expected start up in the first half of 2012. Husky is the operator and holds a 62.4% working interest in this project. Bone Creek, where Husky holds a 95% working interest, is in the initial design phase with a potential start up in early 2013.

United States

Husky continues to evaluate its Columbia River Basin holdings in Washington and Oregon. The results of the Grey 31-23 well, which was drilled in 2009, are being incorporated into this evaluation. Husky holds up to a 50% working interest in this area.

South East Asia

Offshore China Exploration, Delineation and Development

In January 2010, a significant new natural gas discovery was discovered at Liuhua 29-1, approximately 43 kilometres to the northeast of the Liwan 3-1 field. The discovery well tested natural gas at an equipment restricted rate of 57 mmcf/day, with indications that future well deliveries could exceed 90 mmcf/day. In February 2010, the Liuhua 34-2-2 delineation well was drilled, which was abandoned without testing, followed by the Liwan 3-3-1 exploration well, which resulted in a non-commercial gas discovery in April 2010.

In May 2010, Husky successfully completed the drilling and testing of the Liuhua 29-1-2 appraisal well. This appraisal well, the first on the Liuhua 29-1 field, tested natural gas at an equipment restricted rate of 55 mmcf/day.

Following the drilling of the Liuhua 29-1-2 appraisal well, a new exploration well was drilled at Liwan 5-2-1, which did not encounter hydrocarbons and was plugged and abandoned. This was followed by the successful drilling of the Liuhua 34-3-1 exploration well which encountered natural gas. The well is located approximately 24 kilometres northeast of the Liwan 3-1 gas field, the Company's first major discovery in Block 29/26. This well was later suspended pending further evaluation of the suitability to develop this new field as part of the overall Block 29/26 deepwater gas development project.

After the Liuhua 34-3-1 exploration well, the Liwan 3-1-10 well was drilled, which is the first development well on the Liwan 3-1 field. This well was successfully cased and will be used as a future producing well. Husky then drilled the Liuhua 29-1-3 appraisal well, the second appraisal well on the Liuhua 29-1 field. The well encountered quality reservoir sands with approximately 60 metres of gas pay and was cased for possible future re-entry and completion as a producing well. The well was drilled approximately three kilometers north of the initial Liuhua 29-1 discovery.

In November 2010, Husky successfully drilled the Liwan 3-1-11 appraisal well with the aim of testing the eastern part of the Liwan 3-1 field. The well encountered a quality gas charged reservoir and was cased for future re-entry and completion as a producing well. In December 2010, the Liwan 3-1-9 development well and in late January 2011 the Liwan 3-1-5 development well were completed as part of the nine well development program for the Liwan 3-1 field. Husky is currently drilling the Liwan 3-1-8 development well.

Liwan 3-1 is the first deepwater development offshore project in China. Following field delineation of the Liwan 3-1 natural gas field, Husky submitted the Original Gas In-Place report to the Government of China in late 2009 which was approved in 2010. In early December 2010, Husky Oil China Ltd. ("HOCL") signed a Heads of Agreement with CNOOC which specifies key principles of the joint venture to fund, develop and operate the Liwan 3-1 deep water gas field, shallow water and onshore gas processing facilities. This document is a precursor to the Supplemental Development Agreement ("SDA") which will be the definitive agreement governing these issues. The SDA is currently in the drafting stage. Husky expects the plan of development for the Liwan 3-1 field to be submitted in the first quarter of 2011 and is currently tendering all of the deep water equipment and installation activity. Under the current plan, the Liwan 3-1 and Liuhua 34-2 fields on Block 29/26 will be developed in parallel, with first gas production targeted in late 2013. The plan of development for the Liuhua 29-1 field is targeted for submission in 2012, after appraisal drilling and evaluation work has been completed.

The Liwan 3-1 natural gas field, which is located approximately 300 kilometres southeast of Hong Kong, will use a subsea production system connected to a central shallow water platform by flow lines. The platform will be connected by pipeline to an onshore gas plant with access to the energy markets of Hong Kong and Mainland China. Husky and development partner, CNOOC, have established a joint marketing group for the sale of Liwan 3-1 natural gas and associated natural gas liquids. The Liuhua 34-2 and Liuhua 29-1 discoveries will be tied into the proposed Liwan 3-1 shallow water infrastructure.

On Block 63/05 in the Qiongdongnan Basin, 50 kilometres south of Hainan Island, processing of new 2-D and 3-D seismic data has been completed and the data is currently being interpreted. A decision will be made in the first quarter of 2011 on the drilling of an exploration well which is planned for later in the year. Husky holds a 100% interest in Block 63/05, for which CNOOC has the right to participate up to 51%.

On Block 04/35 in the East China Sea, a decision was made to relinquish the block at the end of the first exploration term of the PSC following the results of the HZ 8-1-1 exploration well which was drilled in April 2010 and did not encounter hydrocarbons.

Indonesia Exploration and Development

In October 2010, the Government of Indonesia approved the extension of the existing Madura Strait PSC that was originally awarded in 1982. The approval provides Husky and its partner, CNOOC, a 20-year extension to the existing contract which would have expired in 2012. This extension provides the basis for the development of the Madura BD field as the gas sales agreements are in place and the plan of development has been approved by the Indonesian government. Front end engineering was completed in 2010. The engineering tendering process is currently underway.

Both Husky and CNOOC agreed to sell a 10% equity stake in Husky Oil (Madura) Ltd. ("HOML") to Samudra Energy Ltd., through its affiliate SMS Development Ltd. Following the completion of the sale in January 2011, Husky and CNOOC each hold a 40% equity interest in HOML with the remaining 20% held by SMS Development Ltd.

In late 2009, Husky acquired 1,020 kilometres of new 2-D seismic on the North Sumbawa II Block. Husky will use this data to define an exploration prospect for future drilling, which is currently planned to commence in 2012. Husky holds a 100% interest in the North Sumbawa II Block, comprised of 5,000 square kilometres in the East Java Sea, and may seek to farm-out part of its working interest prior to drilling.

6.2 Midstream

In 2010, Husky commenced its pipeline commitment on the Keystone Pipeline system which ships Canadian crude oil from Hardisty, Alberta to Patoka, Illinois. In 2010, Husky received regulatory approval to add an additional 300,000 barrel storage tank at Hardisty. This tank will be connected to the Keystone Pipeline. Construction of the new tank is expected to be completed in 2012.

6.3 Downstream

Lima, Ohio Refinery

The Lima, Ohio Refinery successfully completed a turnaround on the fluid catalytic cracker, coker and associated units in 2010. Several large safety, environmental, reliability, and optimization projects were completed. The refinery continues to advance short term reliability and profitability projects and is evaluating a staged repositioning approach pending an improvement in the light/heavy crude differential outlook. Front end engineering design has now begun on a 20 mbbls/day kerosene hydrotreater, which will improve distillate production capability and flexibility at the Lima Refinery. The engineering is expected to be completed in the first quarter of 2011.

Toledo, Ohio Refinery

Husky and BP announced the sanction of the Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery in the first quarter of 2010. This project will improve the efficiency and competitiveness of the refinery by reducing energy consumption and lowering operating costs with the replacement of two naphtha reformers and one hydrogen plant with a 42 mbbls/day continuous catalyst regeneration reformer system plant. The project is continuing as planned and construction formally commenced in August 2010. The refinery continues to advance a multi-year program to improve operational integrity and plant performance and reduce operating costs and environmental impacts.

Retail

At the end of 2010, Husky completed the rebranding of all 98 sites in Eastern Canada acquired in late 2009. The Company's total number of fuel outlets at the end of 2010 was 555.

7.0 Results of Operations

7.1 Segment Earnings

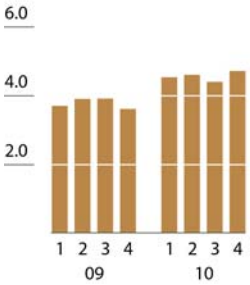
Segment Earnings

	Earnings (Loss) before Income Taxes			Net Earnings (Loss)			Capital Expenditures [1]		
($ millions)	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Upstream	**1,597**	1,560	4,757	**1,135**	1,113	3,377	**3,171**	2,326	3,580
Midstream									
Upgrading	**31**	77	351	**22**	54	246	**176**	69	99
Infrastructure and Marketing	**219**	279	321	**160**	200	224	**40**	25	94
Downstream									
Canadian Refined Products	**156**	198	143	**115**	141	104	**245**	81	155
U.S. Refining and Marketing	**(32)**	195	(635)	**(20)**	124	(403)	**257**	260	133
Corporate, Eliminations and Interest Expense	**(413)**	(352)	208	**(239)**	(216)	203	**67**	36	47
Total	**1,558**	1,957	5,145	**1,173**	1,416	3,751	**3,956**	2,797	4,108

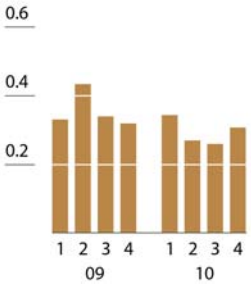
[1] *Excludes capitalized costs related to asset retirement obligations incurred during the period and the BP joint venture transaction.*

7.2 Summary of Quarterly Results

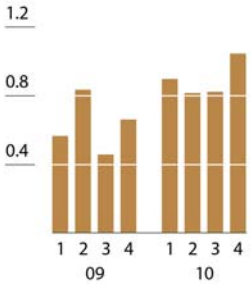
Sales & Operating Revenues
($ billions)



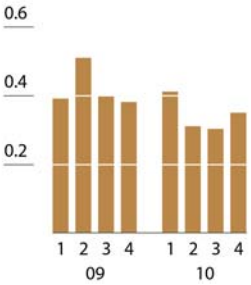
Net Earnings
($ billions)



Cash Flow from Operations[1]
($ billions)



Net Earning Per Share
($ per share)

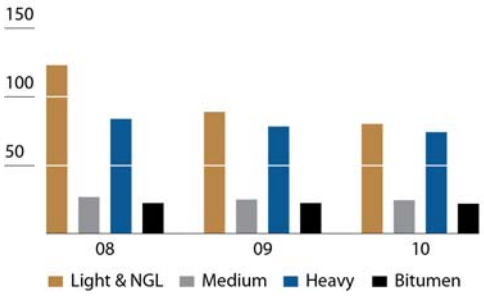


[1] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

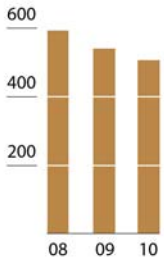
7.3 Upstream

2010 Earnings $1,135 Million

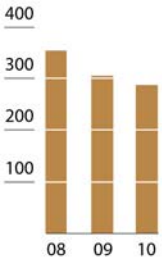
Production
Oil
(mbbls/day)



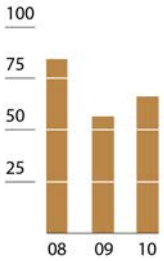
Production
Natural Gas
(mmcf/day)



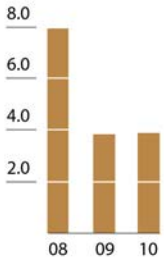
Production
Combined
(mboe/day)



Average Price Realized
Crude Oil
($/bbl)



Average Price Realized
Natural Gas
($/mcf)



Average Sales Prices Realized	2010	2009	2008
Crude oil *($/bbl)*			
Light crude oil & NGL	**76.90**	62.70	97.28
Medium crude oil	**64.92**	56.37	81.79
Heavy crude oil [1]	**58.91**	52.54	71.98
Bitumen [1]	**57.84**	51.90	70.24
Total average	**66.70**	57.11	84.96
Natural gas *($/mcf)*			
Average	**3.86**	3.83	7.94

[1] *A portion of the Company's heavy crude oil production meets the U.S. Securities and Exchange Commission's definition of bitumen.*

Upstream Earnings Summary

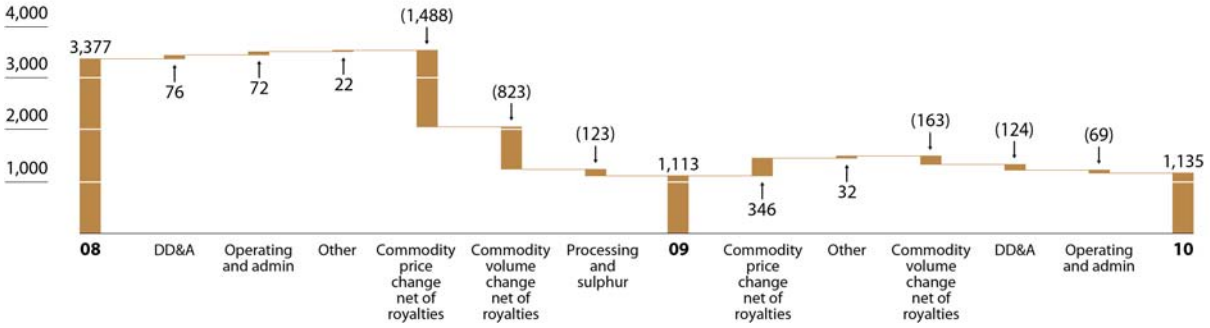
($ millions)	2010	2009	2008
Gross revenues	**5,744**	5,313	9,932
Royalties	**978**	861	2,043
Net revenues	**4,766**	4,452	7,889
Operating and administration expenses	**1,599**	1,495	1,596
Depletion, depreciation and amortization	**1,572**	1,397	1,505
Other (income) expense	**(2)**	–	31
Income taxes	**462**	447	1,380
Net earnings	**1,135**	1,113	3,377

Upstream earnings were $22 million higher in 2010 compared with 2009 primarily due to the higher average prices realized on crude oil and bitumen and the settlement of redetermined participation interests for Terra Nova, partially offset by lower crude oil and natural gas production in 2010 compared with 2009, the impact of the Enbridge Line 6A/6B shutdowns and increased depletion in South East Asia.

During 2010, the average realized price increased 17% to $66.70/bbl for crude oil, NGL and bitumen compared with $57.11/bbl during the same period in 2009. Realized natural gas prices averaged $3.86/mcf during 2010 compared with $3.83/mcf in 2009. Higher U.S. dollar crude oil and natural gas pricing was partially offset by the strengthening of the Canadian dollar against the U.S. dollar.

The Enbridge Line 6A/6B shutdowns caused a widening in the light/heavy crude oil differential which negatively impacted medium and heavy crude oil and bitumen realized prices as a result of industry wide inventory buildup in Western Canada. This resulted in an estimated $60 million negative impact to Upstream net earnings for the year.

After Tax Earnings Variance Analysis
($ millions)



Daily Gross Production

		2010	2009	2008
Crude oil	*(mbbls/day)*			
Western Canada				
Light crude oil & NGL		**23.0**	22.8	24.6
Medium crude oil		**25.4**	25.4	26.9
Heavy crude oil [1]		**74.5**	78.6	84.3
Bitumen [1]		**22.3**	23.1	22.7
		145.2	149.9	158.5
Atlantic Region				
White Rose – light crude oil		**31.2**	45.2	73.2
North Amethyst – light crude oil		**7.0**	–	–
Terra Nova – light crude oil		**8.5**	10.0	12.9
		46.7	55.2	86.1
China				
Wenchang – light crude oil & NGL		**10.7**	11.1	12.2
		202.6	216.2	256.8
Natural gas	*(mmcf/day)*	**506.8**	541.7	594.4
Total	*(mboe/day)*	**287.1**	306.5	355.9

[1] *A portion of the Company's heavy crude oil production meets the U.S. Securities and Exchange Commission's definition of bitumen.*

Upstream Revenue Mix

Percentage of Upstream Net Revenues	2010	2009	2008
Crude oil			
Light crude oil & NGL	**36%**	35%	41%
Medium crude oil	**11%**	10%	8%
Heavy crude oil	**29%**	29%	24%
Bitumen	**8%**	9%	6%
	84%	83%	79%
Natural gas	**16%**	17%	21%
	100%	100%	100%

During 2010, crude oil, bitumen and NGL production decreased by 13.6 mbbls/day or 6% compared with 2009, primarily due to the decline in production from White Rose as a result of declines from peak production rates post the 2009 turnaround and natural reservoir declines, partially offset by production at North Amethyst, which commenced production on May 31, 2010. At Terra Nova, scheduled maintenance and operational (H_2S contamination) issues resulted in reduced production in 2010 relative to the prior year.

During 2010, crude oil and NGL production from Western Canada decreased by 4.7 mbbls/day or 3% compared with 2009 primarily due to decreased heavy oil production which was impacted by extremely wet weather conditions in the third quarter and the subsequently delayed drilling program in the fourth quarter of 2010.

Production from natural gas decreased by 34.9 mmcf/day or 6% in 2010 compared with 2009 due to lower capital expenditures on development and natural reservoir decline, partially offset by additional production from the west central Alberta acquisition which closed on November 30, 2010.

2011 Production Guidance and 2010 Actual

Gross Production

		Guidance 2011	Year ended December 31 2010	Guidance 2010
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		75 – 80	**81**	81 – 84
Medium crude oil		25 – 30	**25**	25 – 27
Heavy crude oil & bitumen		95 – 105	**97**	94 – 97
		195 – 215	**203**	200 – 208
Natural gas	*(mmcf/day)*	560 – 610	**507**	510 – 520
Total barrels of oil equivalent	*(mboe/day)*	290 – 315	**287**	285 – 295

Husky's 2011 guidance is consistent with the Company's target of three to five percent annual growth. Recent acquisitions will offset the base production decline and increased capital expenditures in late 2010 and early 2011 will begin to contribute to production in late 2011. The Company's production for the year ended December 31, 2010 is within the revised production guidance set by the Company in the second quarter of 2010.

Factors that could potentially impact Husky's production performance for 2011 include, but are not limited to:

- Performance on recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields.
- Unplanned or extended maintenance and turnarounds at any of the Company's production, upgrading, refining, pipeline or offshore assets.
- Business interruptions due to unexpected events such as severe weather, fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events.
- Significant declines in crude oil and natural gas commodity prices which may result in the decision to temporarily shut-in production.
- Foreign operations and related assets which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalty rates averaged 17% of gross revenue in 2010 compared with 16% in 2009. Royalty rates in Western Canada averaged 15% compared with 13% in 2009 primarily as a result of increased commodity prices. In the Atlantic Region, the average rate was 24% in 2010 compared with 25% in 2009. The lower rate is attributable to the North Amethyst field which is subject to a basic royalty rate of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Rates at North Amethyst will increase and reach the same level as Terra Nova and White Rose after certain project payouts as prescribed in the royalty regulations are met. Royalty rates in Wenchang averaged 23% compared with 17% in 2009 due to the sliding scale royalty clause in the PSC that results in higher rates in a higher commodity price environment.

Operating Costs

(millions of dollars)	**2010**	2009	2008
Western Canada	**1,199**	1,124	1,249
Atlantic Region	**176**	177	157
International	**24**	23	22
Total	**1,399**	1,324	1,428
Unit operating costs *($/boe)*	**13.33**	11.82	10.93

Total Upstream operating costs in 2010 increased to $1,399 million from $1,324 million. Total upstream unit operating costs in 2010 averaged $13.33/boe compared with $11.82/boe in 2009 due to higher costs combined with lower production. Operating costs in Western Canada increased to $1,199 million from $1,124 million and averaged $14.42/boe in 2010 compared with $12.83/boe in 2009 primarily as a result of increased energy, servicing, treating and maintenance costs, increased handling, transportation and disposal of increased water and emulsion production, as well as lower production in 2010 compared with 2009. The increase is also due to additional well work overs resulting from acquisitions, and additional perforation activity to stimulate production at Tucker.

Operating costs in the Atlantic Region averaged $10.33/boe or $176 million in 2010 compared with $8.73/boe or $177 million in 2009 primarily as a result of lower production as well as increased vessel costs, servicing and maintenance costs at White Rose and North Amethyst offset by lower fuel and labour costs.

Operating costs at the South China Sea offshore operations were $24 million or $6.06/boe in 2010 compared with $23 million or $5.35/boe in 2009 primarily as a result of lower production.

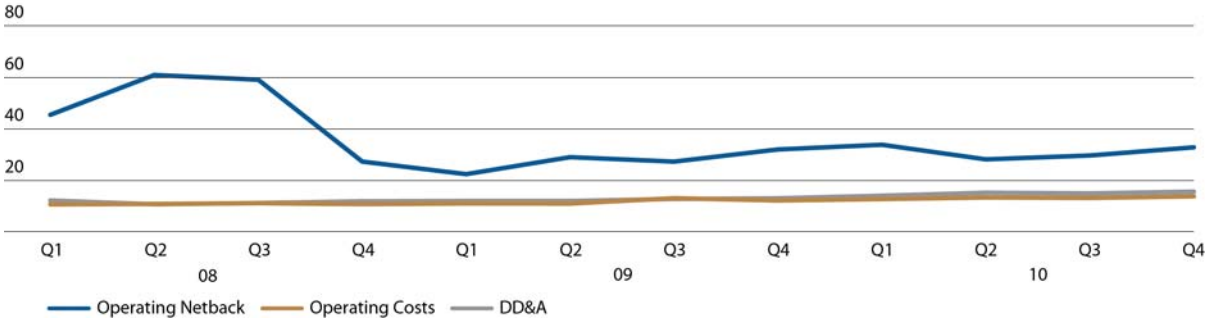
Depletion, Depreciation and Amortization ("DD&A")

DD&A under the full cost method of accounting for oil and gas activities is calculated on a country-by-country basis. The DD&A rate is calculated by dividing the capital costs subject to DD&A by the proved oil and gas reserves expressed as equivalent barrels ("boe"). The resultant dollar per boe is assigned to each boe of production to determine the DD&A expense for the period.

During 2010, total unit DD&A was $15.00/boe compared with $12.49/boe during 2009. The higher DD&A rate in 2010 was primarily due to a larger full cost base in China and the Atlantic Region compared with 2009 primarily as a result of relinquished exploration blocks and dry holes in China as well as additions related to the development program at North Amethyst.

At December 31, 2010, capital costs in respect of unproved properties and major development projects were $4.2 billion compared with $4.0 billion at the end of 2009. These costs are excluded from the Company's DD&A calculation until the unproved properties are evaluated and proved reserves are attributed to the project or the project is deemed to be impaired.

Operating Netback[1], Unit Operating Costs and DD&A
($/boe)



[1] *Operating netbacks are Husky's average price less royalties and operating costs on a per unit basis.*

Other Items

In 2008, a drilling contract previously treated as an embedded derivative no longer met the criteria and the related accounting treatment was discontinued. A loss of $101 million ($71 million after tax) was recorded in 2008. This was partially offset by a gain of $69 million on the sale of 50% of the shares of HOML to CNOOC Southeast Asia Limited in 2008.

Upstream Capital Expenditures

In 2010, Upstream capital expenditures were $3,171 million relative to the revised 2010 capital expenditure program of $3,150 million. Upstream capital expenditures were $2,235 million (70%) in Western Canada, $492 million (16%) in the Atlantic Region and $444 million (14%) in South East Asia. Husky's major projects remain on schedule.

Upstream Capital Expenditures [1]

($ millions)	**2010**	2009	2008
Exploration			
Western Canada	**441**	266	680
Atlantic Region	**96**	95	160
Northwest United States	**–**	25	60
International	**381**	495	225
	918	881	1,125
Development			
Western Canada	**1,794**	923	1,881
Atlantic Region	**396**	510	569
International	**63**	12	5
	2,253	1,445	2,455
	3,171	2,326	3,580

[1] *Excludes capitalized costs related to asset retirement obligations incurred during the period and the BP joint venture transaction.*

Western Canada and Oil Sands Drilling (wells)		2010		2009		2008	
		Gross	**Net**	Gross	Net	Gross	Net
Exploration	Oil	**60**	**51**	18	9	80	70
	Gas	**37**	**31**	37	22	102	79
	Dry	**8**	**8**	7	6	27	23
		105	**90**	62	37	209	172
Development	Oil	**815**	**722**	315	278	685	578
	Gas	**73**	**53**	122	61	435	270
	Dry	**10**	**9**	7	7	36	36
		898	**784**	444	346	1,156	884
Total		**1,003**	**874**	506	383	1,365	1,056

Western Canada

During 2010, Husky invested $2,235 million on exploration and development throughout the Western Canada Sedimentary Basin compared with $1,189 million in 2009. Of this, $943 million was invested on oil exploration and development and $426 million was invested on natural gas exploration and development compared with $408 million for oil exploration and development and $375 million for natural gas exploration and development in 2009. The Company drilled 874 net wells in the basin resulting in 773 net oil wells and 84 net natural gas wells compared with 287 net oil wells and 83 net natural gas wells in 2009. In addition, $134 million was spent on production optimization initiatives in 2010. Capital expenditures on facilities, land acquisition and retention and environmental protection amounted to $331 million and $401 million was primarily spent on acquisition of natural gas properties in west central Alberta.

Husky's major gas resource and conventional high impact exploration program is conducted in various regions along the foothills and northern plains of Alberta and British Columbia and in the deep basin region of Alberta. In 2010, $208 million of the capital expenditures was invested for exploration in these natural gas prone areas, approximately 87% of which was invested on gas resource plays. Capital expenditures on gas resource plays with natural gas liquids potential accounted for 65% of exploration spending in this area. An additional $47 million of the natural gas exploration and development capital expenditures was spent on follow-up activities in these regions during 2010 including tie-ins, facility installation and development drilling.

During 2010, capital expenditures for the Sunrise Energy Project were $66 million compared with $29 million in the same period of 2009. Capital expenditures at Tucker were $117 million compared with $11 million in the same period in 2009. This increase is due to remediating older wells and drilling 32 new wells in 2010, compared to the drilling of three wells in 2009.

The following table discloses Husky's offshore and international drilling activity during 2010:

Offshore and International Drilling Activity

Canada - Atlantic Region			
Glenwood H-69	WI 100%	Stratigraphic test	Exploratory
North Amethyst G-25-1	WI 68.875%	Water injection	Development
North Amethyst G-25-2	WI 68.875%	Production	Development
North Amethyst G-25-3	WI 68.875%	Production	Development
North Amethyst G-25-4	WI 68.875%	Water injection	Development
North Amethyst H-14	WI 68.875%	Stratigraphic test	Delineation
West White Rose E-18-10	WI 68.875%	Production	Development
South East Asia - China			
Liuhua 29-1-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liuhua 34-2-2 Block 29/26	WI 100% [(1)]	Stratigraphic test	Delineation
Liwan 3-3-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liuhua 29-1-2 Block 29/26	WI 100% [(1)]	Stratigraphic test	Delineation
Liwan 5-2-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liuhua 34-3-1 Block 29/26	WI 100% [(1)]	Stratigraphic test	Exploratory
Liwan 3-1-10 Block 29/26	WI 49%	Production	Development
Liuhua 29-1-3 Block 29/26	WI 100% [(1)]	Stratigraphic test	Delineation
Liwan 3-1-11 Block 29/26	WI 100% [(1)]	Stratigraphic test	Delineation
Liwan 3-1-9 Block 29/26	WI 49%	Production	Development
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development
HZ 8-1-1 Block 04/35	WI 100% [(1)]	Stratigraphic test	Exploratory

[(1)] *CNOOC has the right to participate in development of discoveries up to 51%.*

Atlantic Region Development

During 2010, $396 million was invested for Atlantic Region development projects primarily for the North Amethyst and West White Rose satellite tie-back development projects, including drilling operations at North Amethyst and completion of facilities construction and installation. At West White Rose, capital expenditures focused on drilling, advancing engineering design and planning.

Atlantic Region Exploration

During 2010, Husky spent $96 million primarily on the Glenwood H-69 exploration well northwest of the West White Rose field and geological and geophysical data and studies.

Offshore China and Indonesia

During 2010, $444 million was spent on offshore China projects, the drilling of four exploration, four delineation and three development wells on Block 29/26 in the South China Sea and one exploration well on Block 04/35 in the East China Sea.

2011 Upstream Capital Program

($ millions)		
Western Canada	- oil and gas	2,450
	- oil sands	415
Atlantic Region		350
International		1,180
Total Upstream capital expenditures		4,395

Note: Capital program excludes capitalized administration costs, capitalized interest and asset retirement obligations incurred.

The 2011 capital program will enable Husky to build on the momentum achieved in accelerating near-term production, and represents an increase of over 20% from the 2010 program, including the acquisition of producing properties in Alberta and northeast British Columbia from ExxonMobil Canada Ltd. which closed in the first quarter of 2011. The capital program enables the Company to advance its three major growth pillars in the Oil Sands, Atlantic Region and in South East Asia.

Upstream capital spending for Western Canada is targeted at opportunities offering the highest potential returns and focuses on the Company's heavy oil, oil and liquid-rich gas resources plays. Highlights include Phase I of the Sunrise Energy Project, heavy oil investment, including an increased focus on the use of horizontal wells to access producing zones, and advancement of the 8,000 bbls/day South Pikes Peak heavy oil thermal project. Spending has also been allocated to advance the Company's liquid rich gas resource play developments and new oil resource play exploration and development.

In the Atlantic Region, spending is concentrated on the continued development drilling at North Amethyst and West White Rose.

In South East Asia, capital spending is focused on continuing the development of the deep water Liwan Gas Project and exploration and development programs offshore China and Indonesia.

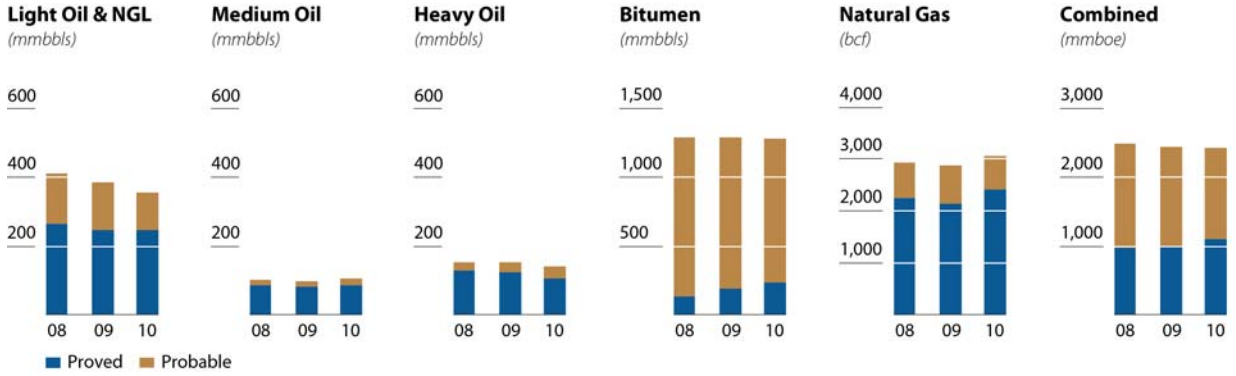
Upstream Planned Turnarounds

The annual maintenance turnaround for the *SeaRose FPSO* is scheduled for 16 days in July 2011. The next turnaround at Terra Nova is scheduled to commence in July 2011.

Off-station turnaround planning for the *SeaRose FPSO* for 2012, to address the maintenance of the propulsion system, is currently being progressed. Husky continues to investigate the various options available for this work.

Oil and Gas Reserves

The following oil and gas reserves disclosure has been prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") effective December 31, 2010. In prior years Husky applied for and was granted an exemption from certain of the provisions of NI 51-101, which permitted the Company to present oil and gas reserves disclosures in accordance with the rules of the United States Securities and Exchange Commission guidelines and the United States Financial Accounting Standards Board (the "U.S. Rules"). This exemption is no longer available for the Company's reserves reporting in Canada, although the Company has received an exemption from the Canadian Securities Administrators which allows the Company to also disclose its reserves under the U.S. Rules as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101. The information in accordance with the U.S. Rules is included in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com .

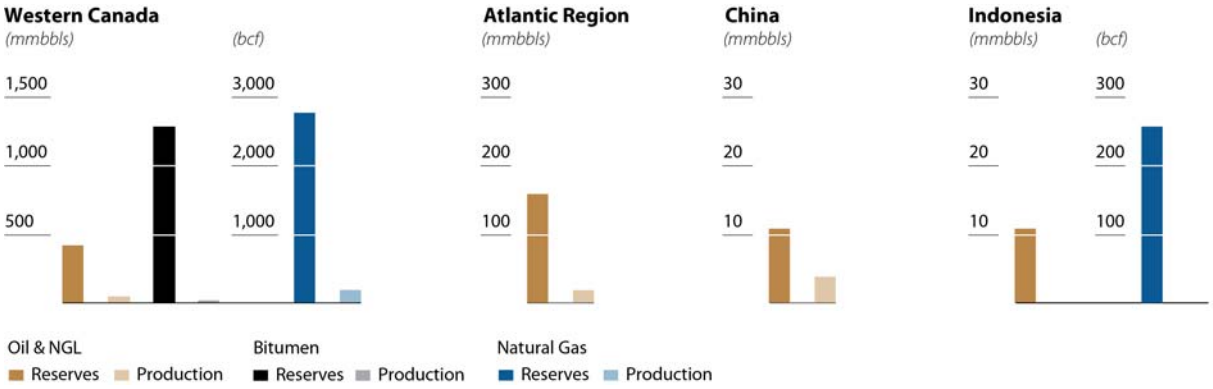


The Company's complete Statement of Oil and Gas Reserves Data and Other Oil and Gas Information in accordance with NI 51-101 is contained in Husky's Annual Information Form available at www.sedar.com or Husky's Form 40-F available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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

At December 31, 2010, Husky's proved oil and gas reserves were 1,081 mmboe, up from 1,004 mmboe at the end of 2009. The net addition to proved reserves, including acquisitions and divestitures, represents 174% of 2010 production. Major additions to proved reserves in 2010 included:

- the extension through additional drilling and seismic interpretation of the Sunrise Energy Project that resulted in booking 56 mmbbls of bitumen to proved undeveloped reserves;
- the booking of 44 mmboe of natural gas and natural gas liquids to proved undeveloped reserves at Madura following the extension of the PSC;
- the acquisition in the Ram River area in west central Alberta, which resulted in booking of proved natural gas reserves of 197 bcf; and
- the extension of proved reserves at Ansell in the Alberta Deep Basin area resulting in the booking of 17 mmboe of natural gas and natural gas liquids.



Note: Reserves are total proved plus probable.

Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					Atlantic Region					
(forecast prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equiva-lent Units *(mmboe)*
Proved reserves at December 31, 2009	145	84	121	200	2,113	93	9	–	652	2,113	1,004
Revision of previous estimate	(11)	4	1	(13)	(14)	8	2	–	(9)	(14)	(11)
Purchase of reserves in place	1	–	–	–	206	–	–	–	1	206	36
Sale of reserves in place	–	–	–	–	(2)	–	–	–	–	(2)	–
Discoveries, extensions and improved recovery	7	9	15	68	142	4	9	209	112	351	170
Price revision	–	–	–	–	(74)	–	–	–	–	(74)	(13)
Production	(9)	(9)	(27)	(8)	(185)	(17)	(4)	–	(74)	(185)	(105)
Proved reserves at December 31, 2010	**133**	**88**	**110**	**247**	**2,186**	**88**	**16**	**209**	**682**	**2,395**	**1,081**
Proved and probable reserves at December 31, 2010	**176**	**108**	**143**	**1,287**	**2,766**	**159**	**22**	**258**	**1,895**	**3,024**	**2,399**
At December 31, 2009	191	100	152	1,294	2,638	167	24	258	1,928	2,896	2,411

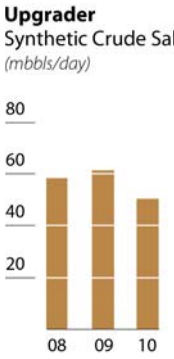
Reconciliation of Proved Developed Reserves

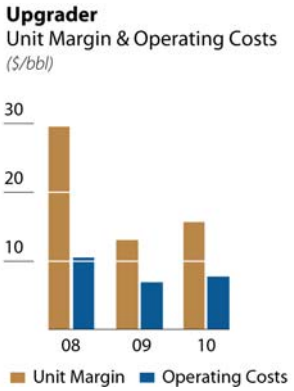
	Canada						International		Total		
	Western Canada					Atlantic Region					
(forecast prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves at December 31, 2009	123	79	87	67	1,667	64	9	–	429	1,667	707
Revision of previous estimate	(8)	5	15	(10)	46	17	2	–	21	46	28
Purchase of reserves in place	1	–	–	–	204	–	–	–	1	204	35
Sale of reserves in place	–	–	–	–	(2)	–	–	–	–	(2)	–
Discoveries, extensions and improved recovery	4	4	7	2	59	–	–	–	17	59	27
Price revision	–	–	–	–	(68)	–	–	–	–	(68)	(11)
Production	(9)	(9)	(27)	(8)	(185)	(17)	(4)	–	(74)	(185)	(105)
Proved developed reserves at December 31, 2010	**111**	**79**	**82**	**51**	**1,721**	**64**	**7**	**–**	**394**	**1,721**	**681**

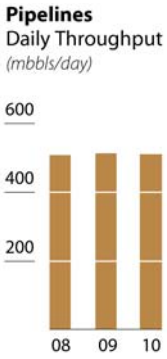
7.4 Midstream

2010 Earnings $182 Million

Total Midstream net earnings in 2010 were $182 million, down from $254 million in 2009. The decrease is primarily due to increased Upgrader depreciation and amortization in 2010 compared to 2009 as well as unrealized losses on natural gas storage contracts in 2010 compared with unrealized gains in 2009, partially offset by increased upgrader and pipeline margins.







Upgrading Earnings Summary

($ millions, except where indicated)		2010	2009	2008
Gross revenues		**1,570**	1,572	2,435
Gross margin		**311**	296	633
Operating and administration expenses		**185**	188	255
Other recoveries		**(5)**	(3)	(4)
Depreciation and amortization		**100**	34	31
Income taxes		**9**	23	105
Net earnings		**22**	54	246
Upgrader throughput [1]	*(mbbls/day)*	**65.4**	74.1	71.1
Synthetic crude oil sales	*(mbbls/day)*	**54.1**	61.8	58.7
Upgrading differential	*($/bbl)*	**14.52**	11.89	28.77
Unit margin	*($/bbl)*	**15.73**	13.11	29.48
Unit operating cost [2]	*($/bbl)*	**7.76**	6.92	10.54

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

Upgrading earnings in 2010 decreased by $32 million compared with 2009 due primarily to an increase in depreciation and amortization as a result of changes in the estimated remaining life of certain components of the Upgrader. The Enbridge Line 6A/6B shutdowns caused a widening in the upgrading differentials which resulted in an estimated $10 million increase to net earnings in 2010. The decrease in throughput was primarily due to a 53-day major scheduled turnaround at the Upgrader that commenced in late August and was completed on October 22, 2010.

Unlike heavy crude oil, synthetic crude oil is a higher value feedstock for many refineries in Canada and the United States. During 2010, the price of Husky's synthetic crude oil averaged $80.97/bbl (2009 - $68.92/bbl) compared with the average cost of blended heavy crude oil from the Lloydminster area of $66.45/bbl (2009 - $57.03/bbl). This resulted in an average synthetic/heavy crude differential of $14.52/bbl (2009 - $11.89/bbl) and a gross unit margin of $15.73/bbl (2009 - $13.11/bbl). Gross unit margin includes secondary products. The cost of upgrading averaged $7.76/bbl compared with $6.92/bbl in 2009, which results in a net margin for upgrading Lloydminster heavy crude of $7.97/bbl, up 29% compared with $6.19/bbl in 2009.

In early February 2011, a fire occurred at the Lloydminster Upgrader. Physical damage to the Upgrader was not extensive, but the Upgrader will run at lower than capacity rates until required repairs and inspection are completed. The duration for which the Upgrader will be under repair and the financial impact of the damage and resulting reduction in sales volumes cannot be reasonably estimated at this time.

Infrastructure and Marketing Earnings Summary

($ millions, except where indicated)		2010	2009	2008
Gross revenues		**7,854**	6,984	13,544
Gross margin				
Pipeline		**124**	106	120
Other		**193**	195	249
		317	301	369
Operating and administration expenses		**21**	19	17
Depreciation and amortization		**43**	36	31
Other (income) expense		**34**	(33)	–
Income taxes		**59**	79	97
Net earnings		**160**	200	224
Commodity volumes marketed	*(mboe/day)*	**952**	912	1,103
Aggregate pipeline throughput	*(mbbls/day)*	**512**	514	507

Infrastructure and marketing net earnings in 2010 decreased by $40 million compared with 2009 due primarily to an unrealized loss of $34 million (gain of $32 million in 2009) resulting from the Company's commodity price risk management activities. Pipeline margins increased due to higher pipeline blending differentials and broker margins.

Midstream Capital Expenditures

Midstream capital expenditures totalled $216 million in 2010 compared to $94 million in 2009. At the Lloydminster Upgrader, Husky spent $84 million primarily for facility reliability projects and $92 million was spent on the scheduled major turnaround. The remaining $40 million was spent on the acquisition of equipment used for sulphur operations and various pipeline upgrades.

Midstream Planned Turnaround

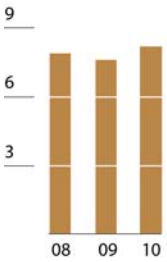
Husky is scheduled to complete a minor turnaround in the third quarter of 2011, primarily for inspection and equipment maintenance. During this time the Upgrader is expected to be at 70% capacity. The next major turnaround is scheduled to commence in the fall of 2013.

7.5 Downstream

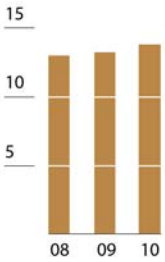
2010 Earnings $95 Million

Total downstream earnings in 2010 were $95 million, down from $265 million in 2009. The decrease is primarily due to lower realized fuel and asphalt gross margins for Canadian Refined Products, lower realized refining margins for U.S. Refining and Marketing, partially offset by higher refinery throughput in 2010 compared with 2009.

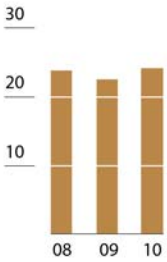
Light Oil Product Marketing
Volume
(millions of litres/day)



Light Oil Product Marketing
Volume per Outlet
(thousands of litres/day)



Asphalt Products
Volume
(mbbls/day)



Canadian Refined Products

Canadian Refined Products Earnings Summary

($ millions, except where indicated)		2010	2009	2008
Gross revenues		**2,975**	2,495	3,564
Gross margin				
Fuel		**87**	111	96
Ethanol		**64**	62	26
Ancillary		**46**	43	41
Asphalt		**160**	169	133
		357	385	296
Operating and administration expenses		**110**	94	72
Depreciation and amortization		**91**	93	81
Income taxes		**41**	57	39
Net earnings		**115**	141	104
Number of fuel outlets [1]		**508**	482	492
Refined products sales volume				
Light oil products	*(million litres/day)*	**8.2**	7.6	7.9
Light oil products per outlet	*(thousand litres/day)*	**13.8**	13.2	13.0
Asphalt products	*(mbbls/day)*	**24.1**	22.6	24.0
Refinery throughput				
Prince George refinery	*(mbbls/day)*	**10.0**	10.3	10.1
Lloydminster refinery	*(mbbls/day)*	**27.8**	24.1	26.1
Ethanol production	*(thousand litres/day)*	**619.3**	676.9	627.2

[1] *Average number of fuel outlets for period indicated.*

During 2010, fuel gross margins were lower than in 2009 primarily due to lower realized market margins, partially offset by higher sales volumes.

Asphalt gross margins slightly decreased compared to the same period in 2009 primarily due to higher input costs resulting in lower realized margins, partially offset by higher sales volumes. The Enbridge Line 6A/6B shutdowns caused a widening in the heavy to light oil crude price differential which resulted in lower feedstock costs to the Lloydminster Refinery. This positively impacted asphalt net earnings by an estimated $15 million in the second half of 2010.

Ethanol gross margins increased in 2010 primarily due to lower input costs which were mostly offset by lower ethanol production. Included in ethanol gross margins in 2010 was $50 million related to government assistance grants compared with $53 million in 2009.

Operating and administration expenses increased primarily as a result of the rebranding of the retail sites in Eastern Canada acquired in late 2009.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary

($ millions, except where indicated)		2010	2009	2008
Gross revenues		**7,107**	5,349	7,802
Gross refining margin		**547**	852	(58)
Processing costs		**378**	423	417
Operating and administration expenses		**8**	7	3
Interest - net		**2**	3	3
Depreciation and amortization		**191**	194	154
Other expense		**–•**	30	–
Income taxes		**(12)**	71	(232)
Net earnings (loss)		**(20)**	124	(403)
Selected operating data:				
Lima Refinery throughput	*(mbbls/day)*	**136.6**	114.6	136.6
Toledo Refinery throughput [1]	*(mbbls/day)*	**64.4**	64.9	60.6
Refining margin	*(U.S. $/bbl crude throughput)*	**7.29**	11.37	(0.86)
Refinery inventory (feedstocks and refined products)	*(mmbbls)*	**11.9**	12.3	11.9

[1] *The BP-Husky Toledo Refinery operating results are included from March 31, 2008, the date the acquisition was completed. Throughput in 2008 represents Husky's share of nine months of operations.*

U.S. refining and marketing earnings decreased in 2010 compared with 2009 as a result of lower realized refining margins and the impact of the Enbridge Line 6A/6B shutdowns on the Toledo Refinery partially offset by higher total throughput. In the third quarter of 2010, the Enbridge Line 6A/6B shutdowns resulted in reduced throughput at the Toledo Refinery due to limited crude oil availability and increased feedstock costs as heavy oil was partially replaced with light oil where available. In the fourth quarter of 2010, the Toledo Refinery benefited from lower feedstock costs resulting from the widening of the heavy to light crude oil differential. The impact to the Toledo Refinery for 2010 was an estimated reduction to net earnings of $18 million. Other expenses in 2009 included $30 million of realized losses on forward contracts for feedstock purchases.

Realized refining margins reflect differences in product configuration, location differences and FIFO accounting for the purchase of crude oil.

The product slate produced at the Lima and Toledo refineries contains approximately 10% to 15% of other products which are sold at discounted market prices compared with gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

The Chicago 3:2:1 crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI while on a FIFO basis crude oil feedstock costs reflect purchases made earlier in the year.

In 2010, Husky's realized refining margin relative to the Chicago 3:2:1 market crack spread was negatively impacted primarily by the product slate at the Lima and Toledo Refinery, which includes products produced that are sold at discounted market prices. In 2009, Husky's realized refining margin relative to the Chicago 3:2:1 market crack spread benefited primarily from the significant rise in WTI during the year, which resulted in higher realized refining margins calculated under FIFO accounting.

In addition, the 10% strengthening of the Canadian dollar against the U.S. dollar compared with 2009 had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Downstream Capital Expenditures

Downstream capital expenditures totalled $502 million for 2010 compared to $341 million in 2009.

In Canada, capital expenditures were $245 million related to the acquisition and rebranding of retail outlets acquired in 2009 as well as upgrades and environmental protection at the retail outlets, refineries and ethanol plants.

In the United States, capital expenditures totalled $257 million. At the Lima Refinery, $132 million was spent on various debottleneck projects, optimizations and environmental initiatives, and $46 million was spent on a scheduled turnaround. At the

Toledo Refinery, capital expenditures totalled $79 million (Husky's 50% share) primarily for engineering work on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection.

Downstream Planned Turnarounds

The Lloydminster Refinery will have a major turnaround in the spring of 2013. The refinery will be shut down during the turnaround for inspections and equipment repair. The turnaround is scheduled to last approximately 21 days.

The Prince George Refinery will have two minor turnarounds for maintenance work in 2011. The first turnaround is scheduled in the second quarter, which is expected to last approximately 9 days. The second turnaround is scheduled in the third quarter and is expected to last approximately 14 days. The next major turnaround will occur in 2012 during the third and fourth quarters. The refinery is scheduled to be shut down for inspections and equipment repair for approximately 30 days.

The next major turnaround at the Toledo Refinery is expected to occur in 2012.

The Lima Refinery will have a major turnaround in 2014 on the Naphtha Hydrotreater, Hydrocracker, Reformer and Diesel Hydrotreater units. The turnaround is scheduled to last approximately 40 days and the refinery will be shut down. Another minor turnaround will occur in 2015 for the Coker and Gasoline Distillation units. The turnaround is scheduled to last approximately 35 days. The remaining process units will operate at 80% capacity during the outage.

7.6 Corporate

2010 Expense $239 Million

Corporate Earnings Summary

($ millions) income (expense)	**2010**	2009	2008
Intersegment eliminations – net	**(47)**	(44)	61
Administration expenses	**(89)**	(69)	(95)
Other income (expense)	**3**	(1)	48
Stock-based compensation	**–**	(1)	33
Depreciation and amortization	**(76)**	(51)	(30)
Interest – net	**(206)**	(191)	(144)
Foreign exchange	**2**	5	335
Income taxes	**174**	136	(5)
Net earnings (loss)	**(239)**	(216)	203

The corporate segment reported a loss in 2010 of $239 million compared with a loss of $216 million in 2009. Administration expenses increased due to higher software expenses, professional services, corporate services, and corporate communications. The increase in depreciation and amortization is due to adjustments to the book value of legacy sites that have been deemed inactive. The increase in net interest in 2010 is due to higher debt levels compared to 2009. Intersegment eliminations are profit included in inventory that has not been sold to third parties at the end of the period.

Foreign Exchange Summary

($ millions)	**2010**	2009	2008
(Gain) loss on translation of U.S. dollar denominated long-term debt	**(90)**	(265)	134
(Gain) loss on contribution receivable	**67**	216	(228)
Other (gains) losses	**21**	44	(241)
Foreign exchange gain	**(2)**	(5)	(335)
U.S./Canadian dollar exchange rates:			
At beginning of year	**U.S. $0.956**	U.S. $0.817	U.S. $1.012
At end of year	**U.S. $1.005**	U.S. $0.956	U.S. $0.817

Consolidated Income Taxes

Consolidated income taxes decreased in 2010 to $385 million from $541 million in 2009 resulting in an effective tax rate of 24.7% for 2010 and 27.6% for 2009.

($ millions)	**2010**	2009	2008
Income taxes as reported	**385**	541	1,394
Cash taxes paid	**783**	1,323	615

Taxable income from Canadian operations is primarily generated through partnerships, with the related income taxes payable in a future period. Accrued liabilities includes nil of cash tax payable in 2011 relating to 2010 taxable income. In 2011, cash tax instalments of $280 million are payable in respect of the 2010 reported earnings, which are not taxable until 2011.

Corporate Capital Expenditures

Corporate capital expenditures of $67 million in 2010 were primarily for computer hardware and software, office furniture, renovations, equipment and system upgrades, construction of a new building in Lloydminster and capitalized interest.

7.7 Fourth Quarter

Consolidated net earnings during the fourth quarter of 2010 were $305 million, an increase of 19% from the previous quarter, but slightly lower compared with the same period in 2009 as a result of lower realized natural gas prices, the stronger Canadian dollar relative to the U.S. dollar, lower Upstream production, increased depletion in South East Asia and the Enbridge Line 6A/6B shutdowns, partially offset by higher average crude oil prices, increased realized refining margins and increased volume in U.S. Downstream and the settlement of the redetermined participation interest for Terra Nova.

Net earnings from the Upstream segment were $322 million in the fourth quarter of 2010, a decrease of $12 million from the same period in 2009. Lower upstream earnings in the fourth quarter of 2010 were largely due to a decrease in total production, the impact of the Enbridge Line 6A/6B shutdowns on realized medium and heavy crude oil and bitumen prices partially offset by increased realized prices for light crude oil, and the settlement of the redetermined participation interests in Terra Nova resulting in a gain of $31.8 million, net of tax. Production for the fourth quarter of 2010 was 280,500 boe/day compared to 291,500 boe/day in the fourth quarter of 2009. The average realized price for the fourth quarter was $68.87/bbl for crude oil, NGL and bitumen compared with $66.65/bbl in the same period in 2009 with higher realized prices for light crude oil partially offset by lower realized prices for medium and heavy crude oil and bitumen. Operating costs were higher in Western Canada and the Atlantic Region in the fourth quarter of 2010 compared to the same period in 2009 due to increased energy, treating, maintenance, labour, and transportation costs. Depletion was higher due to a larger full cost base in the Atlantic Region and China compared with the same period in 2009.

Upgrading recorded a net loss of $7 million in the fourth quarter of 2010 compared to net earnings of $14 million in the same period in 2009. Lower earnings were mainly due to a decrease in the Upgrader throughput of 55.7 mbbls/day in the fourth quarter of 2010 compared to 77.4 mbbls/day in the same period in 2009. The decrease in throughput was due to a scheduled 53-day turnaround at the Lloydminster Upgrader. The decrease in earnings is also attributed to an increase in the depreciation and amortization due to changes in the estimated remaining life of certain components of the Upgrader.

Canadian Refined Products net earnings were $44 million in the fourth quarter compared to $10 million in the same period in 2009 due to higher retail and wholesale market prices. The higher realized market prices were offset by lower government grants, and lower ethanol gross margins due to lower production as a result of a scheduled 39-day turnaround at the Lloydminster Ethanol Plant. Asphalt gross margins were also higher in the fourth quarter due to higher realized market prices, higher sales volumes and lower feedstock costs due to the widening of the heavy to light crude oil price differential resulting from the Enbridge Line 6A/6B shutdowns.

U.S. Refining and Marketing net earnings were $22 million in the fourth quarter compared to a loss of $43 million in the same period in 2009. The increase in earnings was due to higher realized refining margins, higher market crack spreads, and higher total throughput. Throughput was higher in the fourth quarter of 2010 due to a major turnaround completed in the fourth quarter of 2009 at the Lima Refinery.

Corporate net expenses were $122 million in the fourth quarter compared to an expense of $44 million in the same period in 2009. The increase in expenses was due to an increase in administrative expenses, foreign exchange losses, depreciation and amortization, and intersegment eliminations. Administrative expenses increased due to higher software expenses, professional services, corporate services, and corporate communications. Foreign exchange losses increased due to the strengthening of the Canadian dollar and its impact on cash and working capital transactions in the quarter. The increase in depreciation and amortization was a result of adjustments to the book value of legacy sites that have been deemed inactive. Intersegment

eliminations are profit included in inventory that has not been sold to third parties at the end of the period. The increase in the fourth quarter of 2010 compared to the fourth quarter of 2009 was due in large part to additional inventory in Western Canada held for storage and in pipelines to mitigate the impact of selling crude oil to third parties at distressed spot prices due to the impact of the Enbridge Line 6A/6B shutdowns on medium and heavy crude oil and bitumen prices.

7.8 Results of Operations for 2009 compared with 2008

Net earnings in 2009 were $1,416 million compared with $3,751 million in 2008. The decrease of $2,335 million was attributable to the following:

- Upstream earnings decreased by $2,264 million due to lower crude oil and natural gas production, lower average realized prices for commodities, partially offset by a decrease in operating costs and lower DD&A.
- Midstream earnings decreased by $216 million due to lower upgrading differentials and lower margins realized on crude oil and natural gas trading contracts as a result of lower commodity prices, partially offset by a decrease in operating costs due to lower energy costs.
- Downstream earnings increased by $564 million. In Canada, earnings increased by $37 million due primarily to higher margins. Net earnings in the U.S. increased by $527 million due to improved product margins offsetting reduced sales volumes.
- Corporate earnings decreased by $419 million due primarily to lower foreign exchange gains due to the strengthening of the Canadian dollar in 2009 and higher interest expense due to higher debt levels in 2009 compared to 2008.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2010, Husky funded its capital programs, including acquisitions, and dividend payments by cash generated from operating activities, cash on hand, common share issuance, and long-term and short-term debt. At December 31, 2010, Husky had total debt of $4,187 million partially offset by cash on hand of $252 million for $3,935 million of net debt. Husky has no long-term debt maturing until 2012. At December 31, 2010 the Company had $2.7 billion in unused committed credit facilities, $166 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectuses filed in Canada and the U.S. in 2009 of $300 million and U.S. $1.5 billion respectively, and unused capacity under the universal short form base shelf prospectus filed in Canada in 2010 of $2.7 billion. (Refer to Section 8.2).

		2010	2009	2008
Cash flow	- operating activities *($ millions)*	**2,703**	1,918	6,778
	- financing activities *($ millions)*	**1,085**	594	(2,559)
	- investing activities *($ millions)*	**(3,928)**	(3,033)	(3,514)
Debt to capital employed *(percent)*		**21.3**	18.3	12.0
Debt to cash flow from operations *(times)*		**1.2**	1.3	0.3
Corporate reinvestment ratio *(percent)* [1]		**111**	111	66
Interest coverage ratios on long-term debt only [2]				
Earnings		**7.8**	11.1	34.4
Cash flow		**13.7**	17.4	50.9
Interest coverage on ratios of total debt [3]				
Earnings		**7.6**	10.7	33.4
Cash flow		**13.3**	16.7	49.3

[1] *Reinvestment ratio is based on net capital expenditures including corporate acquisitions.*

[2] *Interest coverage on long-term debt on an earnings basis is equal to earnings before interest expense on long-term debt and income taxes divided by interest expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow from operating activities before interest expense on long-term debt and current income taxes divided by interest expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*

[3] *Interest coverage on total debt on an earnings basis is equal to earnings before interest expense on total debt and income taxes divided by interest expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow from operating activities before interest expense on total debt and current income taxes divided by interest expense on total debt and capitalized interest. Total debt includes short and long-term debt.*

Cash Flow from Operating Activities

Cash generated from operating activities amounted to $2.7 billion in 2010 compared with $1.9 billion in 2009. Higher cash flow from operating activities was primarily due to higher crude oil prices, offset by lower production.

Cash Flow from Financing Activities

Cash provided by financing activities was $1,085 million in 2010 compared with $594 million in 2009. The increase was primarily due to the issuance of common shares, partially offset by lower long-term debt issued in 2010 compared to 2009. In March 2010, $700 million of medium-term notes were issued compared to $1.5 billion of long-term notes issued in May 2009.

Cash Flow used for Investing Activities

Cash used for investing activities for 2010 was $3.9 billion compared with $3.0 billion in 2009. Cash invested in both periods was primarily for capital expenditures.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2010, Husky's working capital was $1,256 million compared with $726 million at December 31, 2009.

Movement in Working Capital

($ millions)	**December 31, 2010**	December 31, 2009	Increase/ (Decrease) in Working Capital
Cash and cash equivalents	**252**	392	(140)
Accounts receivable	**1,529**	987	542
Inventories	**1,935**	1,520	415
Prepaid expenses	**34**	12	22
Accounts payable and accrued liabilities	**(2,494)**	(2,185)	(309)
Net working capital	**1,256**	726	530

The decrease in cash was primarily a result of the Company's capital spending exceeding cash flow generated from operating and financing activities. Accounts receivable increased largely as a result of increased crude oil sales and tax instalment advances in 2010. The increase in inventory was due to the increase in inventory in transit on the Keystone Pipeline, and a higher volume of inventory on hand due to mitigation activities in respect of the Enbridge Line 6A/6B shutdowns in 2010. The increase in accounts payable and accrued liabilities was mainly due to higher capital expenditures, higher commodity prices and an increase in inventory compared to 2009.

Sources and Uses of Cash

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and develop reserves, to acquire strategic oil and gas assets, and to repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities, long-term debt, common share issuance, and available committed and uncommitted credit facilities. During times of low oil and gas prices, a portion of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, Husky frequently evaluates the options with respect to sources of long and short-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines. At December 31, 2010, no production was hedged.

At December 31, 2010 Husky had the following available credit facilities:

($ millions)	Available	Unused
Operating facilities	415	299
Syndicated bank facilities	2,750	2,370
Bilateral credit facilities	150	150
Total	3,315	2,819

Cash and cash equivalents at December 31, 2010 totalled $252 million compared with $392 million at the beginning of the year.

At December 31, 2010, Husky had unused committed long and short-term borrowing credit facilities totalling $2.7 billion. In addition, a further $166 million of uncommitted short-term borrowing facilities were available of which a total of $49 million were used in support of outstanding letters of credit.

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the U.S. Securities and Exchange Commission on February 27, 2009. The shelf prospectus enables Husky to offer up to U.S. $3 billion of debt securities in the United States until March 26, 2011. During the 25-month period that the shelf prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of December 31, 2010, U.S. $1.5 billion of long-term debt securities had been issued under this shelf prospectus. On December 21, 2009, Husky filed an additional debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $1 billion of medium-term notes in Canada until January 21, 2012. During the 25-month period that the shelf prospectus is effective, medium-term notes may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of December 31, 2010, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus (refer to Note 13 to the Consolidated Financial Statements).

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 2012. During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement. On December 7, 2010, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of $293 million via an overnight-marketed public offering under this shelf prospectus. The public offering was conducted under the shelf prospectus and supplement to the shelf prospectus. The Company concurrently issued a total of 28.9 million common shares to the principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total gross proceeds of $707 million. The pubic offering and the private placement closed on December 7, 2010.

Asia Pacific Energy Ltd. and HOCL, subsidiaries of Husky, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes. As of December 31, 2010, there was no balance outstanding under these facilities.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility available of $10 million for general purposes. Husky's proportionate share is $5 million. As of December 31, 2010, there was no balance outstanding under this facility.

In 2008, Husky initiated a cash tender offer to purchase any and all of the U.S. $225 million 8.90% capital securities outstanding. At the time of expiration of the tender offer, U.S. $214 million or 95% of the capital securities had been tendered. The remaining capital securities were redeemed in 2008.

In 2008, Husky redeemed the 6.95% medium-term notes - Series E due July 14, 2009. The principal amount was $200 million and the redemption price, including accrued interest, totalled $208 million.

During 2008, Husky repurchased U.S. $63 million of the outstanding U.S. $450 million 6.80% notes due September 2037.

Quarterly dividends of $0.30 ($1.20 annually) per common share were declared totalling $1 billion in 2010. The declaration of dividends will be at the discretion of the Board of Directors, which will consider earnings, capital requirements, the Company's financial condition and other relevant factors.

In the Special Meeting of Shareholders held on February 28, 2011, Husky's shareholders approved amendments to the common share terms, which provide the shareholders with the ability to receive dividends in common shares or in cash. Quarterly dividends would be declared in an amount expressed in dollars per common share and would be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares would be calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash.

Capital Structure

($ millions)	December 31, 2010 Outstanding	Available [1]
Total short-term and long-term debt	4,187	2,819
Common shares, retained earnings and accumulated other comprehensive income	15,493	

[1] *Available short and long-term debt includes committed and uncommitted credit facilities.*

8.3 Cash Requirements

Contractual Obligations and Other Commercial Commitments

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

Contractual Obligations

Payments due by period ($ millions)	2011	2012-2013	2014-2015	Thereafter	Total
Long-term debt and interest on fixed rate debt	232	1,205	1,389	3,325	6,151
Operating leases	105	169	121	117	512
Firm transportation agreements	166	274	331	3,197	3,968
Unconditional purchase obligations [1]	1,970	1,280	50	122	3,422
Lease rentals and exploration work agreements	98	115	238	491	942
Asset retirement obligations [2]	63	117	117	7,293	7,590
	2,634	3,160	2,246	14,545	22,585

[1] *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services and natural gas purchases.*

[2] *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

Based on Husky's 2011 commodity price forecast, the Company believes that its non-cancellable contractual obligations, other commercial commitments and 2011 capital program will be funded by cash flow from operating activities and, to the extent required, by available committed credit facilities, the issuance of long-term debt and by hybrid debt instruments. In the event of significantly lower cash flow, Husky would be able to defer certain projected capital expenditures without penalty.

Estimated Obligations Not Included in the Table

Husky provides a defined contribution plan and a post-retirement health and dental plan for all qualified employees in Canada. The Company also provides a defined benefit pension plan for approximately 119 active employees and 506 retirees and their beneficiaries in Canada. This plan was closed to new entrants in 1991 after the majority of employees transferred to the defined contribution pension plan. Husky provides a defined benefit pension plan for approximately 400 active employees in the United States. This pension plan was established effective July 1, 2007 in conjunction with the acquisition of the Lima Refinery. Husky also assumed a post-retirement welfare plan covering the employees at the Lima Refinery. See Note 18 to the Consolidated Financial Statements.

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery LLC (refer to Note 8 to the Consolidated Financial Statements) which is payable between December 31, 2010 and December 31, 2015 with the final balance due and payable by December 31, 2015. The timing of payments during this period will be determined by the capital expenditures made at the refinery during this same period. At December 31, 2010, Husky's share of this obligation was U.S. $1.4 billion including accrued interest.

Other Obligations

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

The Company has a number of contingent environmental liabilities, which individually have been estimated to be immaterial and have not been reflected in the Company's financial statements beyond the associated asset retirement obligations ("ARO"). These contingent environmental liabilities are primarily related to the migration of contamination at fuel outlets and certain legacy sites where Husky had previously conducted operations. The contingent environmental liabilities involved have been considered in aggregate and based on reasonable estimates the Company does not believe they will result, in aggregate, in a material adverse effect on its financial position, results of operations or liquidity.

8.4 Off-Balance Sheet Arrangements

Accounts Receivable Securitization Program

In the ordinary course of business, Husky engaged in the securitization of accounts receivable. The securitization program permitted the sale of a maximum of $350 million of accounts receivable on a revolving basis. The securitization agreement expired on March 31, 2009 and Husky chose not to renew.

Standby Letters of Credit

In addition, from time to time, Husky issues letters of credit in connection with transactions in which the counterparty requires such security.

Derivative Instruments

Husky utilizes derivative financial instruments in order to manage unacceptable risk. The derivative financial instruments currently outstanding are listed and discussed in Section 8.6, "Financial Risk and Risk Management."

8.5 Transactions with Related Parties and Major Customers

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million respectively to certain management, shareholders, affiliates and directors as part of the U.S. $1.5 billion 5 and 10-year senior notes issued through the existing base shelf prospectus, which was filed in February 2009 (refer to Note 13 to the Consolidated Financial Statements). Subsequent to this offering, U.S. $65 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. The coupon rates offered were 5.90% and 7.25% for the 5 and 10-year tranches respectively. These transactions were measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties. At December 31, 2010, the senior notes were included in long-term debt on the Company's balance sheet.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

A related party is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP") which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at the exchange amount. For 2010, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $44 million (2009 - $90 million). At December 31, 2010, the total value of accounts receivables related to these transactions was nil (2009 - nil).

In February 2011, Husky and TACLP agreed to sell the Meridian cogeneration facility to a related party. Completion of the transaction is subject to consent from Saskatchewan Power Corporation as well as regulatory approval. The transaction is expected to be completed by April 2011.

Husky did not have any customers that constituted more than 10% of total sales and operating revenues during 2010.

8.6 Financial Risk and Risk Management

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates, interest rates, credit risk and changes in fiscal, monetary and other financial policies related to royalties, taxes and others (refer to Section 3.0, "The 2010 Business Environment"). From time to time, the Company will use derivative instruments to manage its exposure to these risks.

Political Risk

Husky is exposed to risk factors associated with operating in developed and developing countries, as well as political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

Environmental Risk

Husky's offshore operations are subject to the risk of blowouts and other catastrophic events, resulting from actions of the Company or its contractors or agents, or those of third parties, that could result in suspension of operations, damage to equipment and harm to personnel, and damage to the natural environment. The consequences of such catastrophic events occurring in deep water operations, in particular, can be more costly and time-consuming to remedy, the remedy may be made

more difficult or uncertain by the extreme pressures and cold temperatures encountered in deep water operations, shortages of equipment and specialist personnel required to work in these conditions, or the absence of appropriate and proven means to effectively remedy such consequences. The costs associated with such events could be material and Husky may not maintain sufficient insurance to address such costs. With the exception of Husky's Mizzen prospect, of which Husky is a non-operator, the Company currently does not participate in offshore deep water drilling operations in Canada; however, Husky's development program in China includes deep water drilling.

The Deepwater Horizon oil spill in the Gulf of Mexico has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil operations. Stricter regulation of offshore oil and gas operations has already been implemented in the Gulf of Mexico. Further regulation, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in the Gulf of Mexico. In the event that similar changes in environmental regulation occur with respect to Husky's operations in the Atlantic Region or in the South China Sea, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

The United States Environmental Protection Agency ("EPA") has promulgated the so-called 'Tailoring Rule', which, beginning on January 2, 2011, phases in over time restrictions on greenhouse gas emissions from stationary sources, including power plants and petroleum refineries, beginning with the largest emitters, where such sources are required to obtain a new or modified permit based on non-greenhouse gas emissions. The EPA has also promulgated regulations requiring data collection, beginning January 1, 2010, and reporting, beginning March 31, 2011, of greenhouse gas emissions from stationary sources in the oil and gas industry emitting more than 25,000 tons per year of greenhouse gases in carbon dioxide equivalent. This reporting requirement applies to Husky's U.S. operations. However, these regulations are subject to challenge in Congress and the courts. Congress is expected to consider in the coming session proposals to block or delay the EPA's regulation of greenhouse gas emissions. Among several legal challenges, the State of Texas, the National Association of Manufacturers and other organizations are seeking a stay of the Tailoring Rule and the EPA's other regulations relating to greenhouse gas emissions from stationary sources. It is not possible to predict the ultimate outcome of these challenges. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky and the pending and anticipated challenges could result in the staying of the regulations. Husky's operations may be impacted by future United States greenhouse gas legislation applying to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require Husky's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

Financial Risk

Husky's financial risks are largely related to commodity prices, refinery crack spreads, foreign exchange rates, interest rates, credit risk, changes in fiscal policy related to royalties and taxes and others. From time to time, Husky uses financial and derivative instruments to manage its exposure to these risks.

Commodity Price Risk Management

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

At December 31, 2010, the Company had third party physical purchase and sale natural gas contracts and financial natural gas storage contracts.

The third party physical purchase and sale contracts have been recorded at their fair value in accrued liabilities and accounts receivable respectively. At December 31, 2010, the balance sheet position of these contracts was $31 million recorded in accounts receivable (2009 - $13 million in accounts receivable). The change in the fair value of these contracts resulted in an unrealized gain of $18 million (2009 - unrealized loss of $38 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Natural gas inventories held in storage relating to the financial natural gas storage contracts are recorded at fair value. At December 31, 2010, the fair value of the inventories was $131 million (2009 - $173 million). The cumulative fair value change on this inventory as of December 31, 2010 was an unrealized loss of $6 million (2009 - unrealized gain of $45 million). The change in the fair value of inventory resulted in an unrealized loss of $51 million (2009 - unrealized gain of $69 million) which has been recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The Company designated certain crude oil purchase and sale contracts as fair value hedges against the changes in the fair value of the inventory held in storage. The assessment of effectiveness for the fair value hedges excludes changes between current market prices and market prices on the settlement date in the future. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of $2 million (2009 - $4 million gain) has been recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income. The crude oil inventory held in storage is recorded at fair value.

At December 31, 2010, the fair value of the inventory was $30 million (2009 - $124 million), resulting in a $2 million unrealized loss (2009 - $1 million loss) recorded in cost of sales in the Consolidated Statements of Earnings and Comprehensive Income.

The Company enters into certain crude oil and purchase sale contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At December 31, 2010, the Company had 3 mmbbls of purchase and sale contracts resulting in an unrealized loss of $8 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income. A portion of the crude oil inventory is sold to third parties and is considered held for trading. This inventory has been recorded at its fair value as the Company is considered a broker-trader. At December 31, 2010, the fair value of the inventory was $72 million, resulting in a $6 million unrealized gain recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

The Company has entered into contracts for future crude oil purchases, whereby there is a requirement to pay the difference between the price paid at delivery of the crude oil and the current market price at a future settlement date. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at December 31, 2010, the fair value of these contracts was $1 million resulting in a loss of $1 million (2009 - $30 million loss) recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Foreign Currency Risk Management

At December 31, 2010, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 6.25% swapped at $1.41 to $211 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $89 million at 5.65% until June 15, 2012.
- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.

At December 31, 2010, the cost of a U.S. dollar in Canadian currency was $0.9946.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. For the year ending December 31, 2010, the impact of these contracts was a realized gain of $26 million (2009 - gain of $16 million) recorded in foreign exchange expense.

During 2009, the Company settled its two remaining forward purchases of U.S. dollars realizing a loss of $9 million recorded in other expenses in the Consolidated Statements of Earnings and Comprehensive Income.

Husky's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of Husky's expenditures are in Canadian dollars. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. 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, 2010, 74% or $3.1 billion of Husky's outstanding debt was denominated in U.S. dollars (100% or $3.2 billion at December 31, 2009). The percentage of the Company's debt exposed to the Cdn/U.S. exchange rate decreases to 67% when cross currency swaps are considered (2009 - 88%).

At December 31, 2010, the Company has designated U.S. $987 million of its U.S. debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered self-sustaining. In 2010, the unrealized foreign exchange gain arising from the translation of the debt was $44 million, net of tax expense of $7 million (2009 - gain of $104 million, net of tax expense of $18 million), which was recorded in Other Comprehensive Income.

Including cross-currency swaps and the debt that has been designated as a hedge of a net investment, 42% of long-term debt is exposed to changes in the Cdn/U.S. exchange rate (2009 - 57%).

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and a major portion of this receivable is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in foreign exchange in current period earnings. At December 31, 2010, Husky's share of this receivable was U.S. $1.3 billion (2009 - U.S. $1.2 billion) including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in Other Comprehensive Income as this item relates

to a self-sustaining foreign operation. At December 31, 2010 Husky's share of this obligation was U.S. $1.4 billion (2009 - U.S. $1.4 billion) including accrued interest.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meets its liabilities when they become due. The Company prepares annual capital expenditure budgets, which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

The following are the contractual maturities of financial liabilities as at December 31, 2010:

Financial Liability *($ millions)*	2011	2012	2013	2014	2015	After 2015
Accounts payable and accrued liabilities	2,494	–	–	–	–	–
Cross currency swaps	–	447	–	–	–	–
Long-term debt	–	782	–	753	303	2,349

The Company's objectives, processes and policies for managing liquidity risk have not changed from the previous year.

Interest Rate Risk Management

At December 31, 2010, Husky had the following interest rate swaps in place:

- U.S. $200 million of long-term debt whereby a fixed interest rate of 7.55% was swapped for rates ranging from LIBOR + 399 bps to LIBOR + 430 bps until November 15, 2016.
- U.S. $300 million of long-term debt whereby a fixed interest rate of 6.20% was swapped for rates ranging from LIBOR + 255 bps to LIBOR + 275 bps until September 15, 2017.
- U.S. $150 million of long-term debt whereby a fixed interest rate of 5.90% was swapped for rates ranging from LIBOR + 349 bps to LIBOR + 350 bps until June 15, 2014.
- CAD $300 million of long-term debt whereby a fixed interest rate of 3.75% was swapped for rates ranging from CDOR + 0.80% to CDOR + 0.85% until March 12, 2015.

During 2010, these swaps resulted in an offset to interest expense of $23 million compared to an offset of less than $1 million in 2009. The amortization of previous interest rate swap terminations resulted in an additional $2 million (2009 - offset of $3 million) interest expense in 2010.

Cross currency swaps resulted in an addition to interest expense of $6 million (2009 - $4 million) in 2010.

Credit and Contract Risk

Husky actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective.

Fair Value of Financial Instruments

The derivative portion of cash flow hedges, fair value hedges, and free standing derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon fair value hierarchy in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3862. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. All of Husky's assets and liabilities that are recorded at fair value on a recurring basis are included in Level 2.

8.7 Outstanding Share Data

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 28, 2011

• common shares	890,708,795
• preferred shares	none
• stock options	28,594,260
• stock options exercisable	16,845,105

At February 28, 2011, 49.2 million common shares were reserved for issuance under the stock option plan. Other than in respect of the performance based options, options awarded under the stock option plan have a maximum term of five years and vest evenly over the first three years (refer to Note 17 to the Consolidated Financial Statements).

8.8 Liquidity Summary

The following information relating to Husky's credit ratings is provided as it relates to Husky's financing costs, liquidity and operations. Specifically, credit ratings affect Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Husky to engage in certain collateralized business activities on a cost effective basis depends on Husky's credit ratings. A reduction in the current rating on Husky's debt by its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in Husky's ratings outlook could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect Husky's ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require Husky to post additional collateral under certain of its contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Under Review	December 15, 2010	March 5, 2010
Senior Unsecured Debt	Baa2	March 5, 2010	April 25, 2001
Standard and Poor's:			
Outlook	Stable	November 30, 2010	July 27, 2006
Senior Unsecured Debt	BBB+	November 30, 2010	July 27, 2006
Dominion Bond Rating Service:			
Trend	Stable	November 26, 2009	March 31, 2008
Senior Unsecured Debt	A (low)	November 26, 2009	March 31, 2008

Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer 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.

On December 15, 2010 Moody's placed Husky Energy Inc.'s Baa2 senior unsecured rating and Ba1 junior subordinated rating on review for a possible downgrade. At this time the outcome of the review is not yet determined.

9.0 Application of Critical Accounting Estimates

Husky's Consolidated Financial Statements have been prepared in accordance with GAAP. Significant accounting policies are disclosed in Note 3 to the Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The following discussion highlights the nature and potential effect of these estimates. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

Full Cost Accounting for Oil and Gas Activities

The indicated change in the following estimates will result in a corresponding increase in the amount of DD&A expense charged to income in a given period:

An increase in:

- estimated costs to develop the proved undeveloped reserves;
- estimated fair value of the ARO related to the oil and gas properties; and
- estimated impairment of costs excluded from the DD&A calculation.

A decrease in:

- previously estimated proved oil and gas reserves; and
- estimated proved reserves added compared to capital invested.

Depletion Expense

All costs associated with exploration and development are capitalized on a country-by-country basis. The aggregate of capitalized costs, net of accumulated DD&A, plus the estimated costs required to develop the proved undeveloped reserves, less estimated salvage values, is charged to income over the life of the proved reserves using the unit of production method.

Withheld Costs

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

Ceiling Test

Each cost centre's capitalized costs are tested for recoverability at least yearly. The test compares the estimated undiscounted future net cash flows from proved oil and gas reserves based on forecast prices and costs to the carrying amount of a cost centre. If the future cash flows are lower than the carrying costs, the cost centre is written down to its fair value. Fair value is estimated using present value techniques, which incorporate risks and other uncertainties as well as the future value of reserves when determining estimated cash flows.

Impairment of Long-lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

Fair Value of Derivative Instruments

Periodically Husky utilizes financial derivatives to manage market risk. Canadian GAAP provides for the recognition, measurement and disclosure requirements for financial instruments and hedge accounting. Refer to Note 20 in the Consolidated Financial Statements.

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through forward market prices and compared with quotes from financial institutions. The estimation of fair value of forward purchases of U.S. dollars is determined using forward market prices.

Asset Retirement Obligation

Husky has significant obligations to remove tangible assets and restore land after operations cease and Husky retires or relinquishes the asset. The Company's ARO primarily relates to the upstream business. The retirement of upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and subsea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the ARO requires that Husky estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, future third-party pricing, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions result in changes to the ARO.

Employee Future Benefits

The determination of the cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the expected future benefit payments. These assumptions include, but are not limited to, attrition, mortality, the rate of return on pension plan assets and salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The fair value of the plan assets are used for the purposes of calculating the expected return on plan assets.

Legal, Environmental Remediation and Other Contingent Matters

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

Income Tax Accounting

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

Business Combinations

Under the purchase method, the acquiring company includes the fair value of the various assets and liabilities of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. In some circumstances the fair value of an asset is determined by estimating the amount and timing of future cash flow associated with that asset. The actual amounts and timing of cash flow may differ materially and may possibly lead to an impairment charged to earnings.

Goodwill

In combination with purchase accounting, any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of purchase accounting, described above, it too is inherently imprecise. Goodwill must be assessed annually for impairment and requires judgment in the determination of the fair value of assets and liabilities.

10.0 Transition to International Financial Reporting Standards

In February 2008, the CICA Accounting Standards Board ("AcSB") confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), for fiscal periods beginning on or after January 1, 2011.

The Company is progressing in its IFRS transition project in preparation for timely completion of the first IFRS interim financial report in the first quarter of 2011. The impact assessment of IFRS accounting policies chosen by the Company has been completed for the January 1, 2010 and December 31, 2010 balance sheets and 2010 year-end results based on the accounting standards and interpretations in effect as at December 31, 2010. The impact of transition to IFRS as presented in the financial statements may require adjustment before comprising part of the first IFRS financial statements reported to shareholders as a result of early adoption of any IFRS issued but not effective until after December 31, 2011 or as a result of changes in financial reporting requirements arising from new or revised standards issued by the IASB or interpretations issued by the International Financial Reporting Interpretations Committee.

The Company has completed its risk assessment of key processes that will be impacted by IFRS. Conversion impacts have been incorporated into existing internal controls over financial reporting and disclosure controls and procedures. No material changes to the internal control framework or entity-level controls have been noted as a result of transition to IFRS.

Refer to Note 24 of the Consolidated Financial Statements for the Company's assessment of the impacts of the transition to IFRS as at January 1, 2010 and December 31, 2010 and for the year ended December 31, 2010. The impact of the transition to IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Specifically, amounts recorded for depletion, depreciation, amortization, accretion expense, asset retirement obligations, fair value measurements, employee future benefits and amounts used in impairment tests for intangible assets, goodwill, inventory and property, plant and equipment are based on estimates. By their nature, these estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change on the financial statements.

Based on the critical accounting estimates outlined in Section 9.0 above, the Company noted that the transition to IFRS result in additional considerations in underlying estimates from those under Canadian GAAP as follows:

Depletion Expense

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. Under IFRS, the aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved reserves using the unit of production method.

Withheld Costs

Costs related to exploration and evaluation activities and major development projects are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed and production commences. At that time, costs are either transferred to property, plant, and equipment or their value is impaired. Impairment is charged directly to profit or loss under IFRS.

Impairment of Long-lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre exceeds its recoverable amount under IFRS. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The determination of the recoverable amount for impairment purposes under IFRS involves the use of numerous assumptions and judgments including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

11.0 Reader Advisories

11.1 Forward-looking Statements

Certain statements in this MD&A are forward-looking statements within the meaning of 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 and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements"). The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements. 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," "target," "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In particular, forward-looking statements in this MD&A include, but are not limited to: the Company's general strategic plans and growth opportunities; anticipated results of the Company's 2011 capital program; annual growth targets; production guidance; factors that could impact the Company's 2011 production performance; the potential effect of risks and other factors on the Company's ability to deliver results in its Upstream, Midstream and Downstream business units; strategic plans for the upstream, midstream and downstream business segments; reserve estimates; exploration, development, and production plans in South East Asia, Western Canada, the Oil Sands and the Atlantic Region; development and production plans; production capacity and timing of production for the Sunrise Energy Project; production volumes and anticipated timing of peak production at North Amethyst; anticipated timing of production at West White Rose and Liwan; drilling plans at North Amethyst and the White Rose; exploration plans at Mizzen and offshore Greenland; timing of submission of development plans for Liwan; development plans and timing of production in Block 29/26; transportation plans at Liwan; potential farm-outs at North Sumbawa II; drilling plans and anticipated timing of production in Western Canada; production optimization and drilling plans for the Tucker Oil Sands Project; testing and implementation of various enhanced recovery techniques in Western Canada; development, drilling and production plans for the McMullen property; production plans for the Pikes Peak South project; conventional and shale gas exploration plans for Western Canada; the Company's coal bed methane program; expansion plans for the Company's facility at Hardisty; reconfiguration plans for the Lima Refinery; Continuous Catalyst Regeneration Reformer Project plans; planned turnarounds to the *SeaRose* FPSO and at Terra Nova; planned turnarounds to the Lloydminster, Lima, Prince George and Toledo refineries; anticipated impacts of and timing of repairs from the February 2011 fire at the Lloydminster upgrader; plans to reposition and upgrade the Toledo Refinery; expectations in respect of the timing of the Terra Nova redetermination; 2011 production guidance; 2011 capital expenditure guidance; the Company's financial strategy and ability to maintain credit ratings; 2011 payments to be made pursuant to existing contractual obligations; anticipated timing and effect of closing of the sale of the Meridian cogeneration facility; and expected effects of the transition to IFRS.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. In addition, information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

The Company's Annual Information Form filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describes the risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, the Company undertakes no obligation to update any forward-looking statement 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 statement.

11.2 Oil and Gas Reserve Reporting

Disclosure of Oil and Gas Reserves and Other Oil and Gas Information

In the past, Husky has sought and been granted by the Canadian Securities Administrators permission to make certain disclosure of its oil and gas activities in accordance with U.S. disclosure requirements. This permission ceased to be available after January 1, 2011, although the Company received an exemption from the Canadian Securities Administrators which allows the Company to also disclose its reserves using U.S. disclosure requirements as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101. The reserve estimates and related disclosures in this document have been prepared in accordance with Canadian Securities Administrators' NI 51-101 effective December 31, 2010. Please refer to "Disclosure of Exemption under National Instrument 51-101" in the Annual Information Form for the year ended December 31, 2010 filed with securities regulatory authorities for further information.

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

11.3 Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on GAAP and also on secondary non-GAAP measurements. The non-GAAP measurements included in this report are: cash flow from operations, operating netback, return on equity, return on average capital employed, debt to capital employed, debt to capitalization, debt to cash flow from operations and corporate reinvestment ratio. None of these measurements are used to enhance the Company's reported financial performance or position. These are useful complementary measurements in assessing Husky's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by GAAP and therefore are unlikely to be comparable to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application. Except as described below, the definitions of these measurements are found in Section 11.4, "Additional Reader Advisories."

Disclosure of Cash Flow from Operations

Husky uses the term "cash flow from operations," which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with GAAP, as an indicator of financial performance. Cash flow from operations or earnings is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

The following table shows the reconciliation of cash flow from operations to cash flow - operating activities for the years ended December 31:

($ millions)		**2010**	2009	2008
Non-GAAP	Cash flow from operations	**3,549**	2,507	5,946
	Settlement of asset retirement obligations	**(60)**	(41)	(56)
	Change in non-cash working capital	**(786)**	(548)	888
GAAP	Cash flow – operating activities	**2,703**	1,918	6,778

Disclosure of Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. This measurement helps management and investors to evaluate the specific operating performance by product at the oil and gas lease level. It is equal to product revenue less transportation costs, royalties and lease operating costs divided by either a barrel of oil equivalent or a mcf of gas equivalent.

11.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis

This MD&A is intended to provide an explanation of financial and operational performance compared with prior periods and the Company's prospects and plans. It provides additional information that is not contained in the Company's financial statements.

Review by the Audit Committee

This MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 28, 2011. Any events subsequent to that date could conceivably materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This MD&A should be read in conjunction with the Consolidated Financial Statements and related notes. The readers are also encouraged to refer to Husky's interim reports filed in 2010, which contain MD&A and Consolidated Financial Statements, and Husky's Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the SEC, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com.

Use of Pronouns and Other Terms

"Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2010 and 2009 and Husky's financial position as at December 31, 2010 and at December 31, 2009.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change their decision to buy, sell or hold the securities of Husky.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with GAAP in Canada. Significant differences between Canadian and United States GAAP are disclosed in the U.S. GAAP reconciliation contained in Form 40-F and available at www.sec.gov.
- Currency is presented in millions of Canadian dollars ("$").
- Gross production and reserves are Husky's working interest prior to deduction of royalty volume.
- Prices are presented before the effect of hedging.
- Light crude oil is 30° API and above.
- Medium crude oil is 21° API and above but below 30° API.
- Heavy crude oil is above 10° API but below 21° API.
- Bitumen is solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure.

Terms

Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Brent Crude Oil	*Prices which are dated less than 15 days prior to loading for delivery*
Capital Employed	*Short and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Coal Bed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Corporate Reinvestment Ratio	*Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations*
Debt to Capital Employed	*Total debt divided by capital employed*
Debt to Capitalization	*Total debt divided by total debt and shareholders' equity*
Debt to Cash Flow from Operations	*Total debt divided by cash flow from operations*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Feedstock	*Raw materials which are processed into petroleum products*
Front End Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Glory Hole	*An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Interest Coverage Ratio	*A calculation of a company's ability to meet its interest payment obligation. It is equal to earnings before income taxes and interest divided by interest paid before deduction of capitalized interest*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Return on Average Capital Employed	*Net earnings plus after tax interest expense divided by average capital employed*
Return on Equity	*Net earnings divided by average shareholder's equity*
Seismic	*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*
Shareholders' Equity	*Shares, retained earnings and accumulated other comprehensive income*
Total Debt	*Long-term debt including current portion and bank operating loans*

"Proved oil and gas reserves" are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

"Proved developed oil and gas reserves" are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Proved Undeveloped" reserves are those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which a relatively major expenditure is required for recompletion. Inclusion of reserves on undrilled acreage is limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

"Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves, but which taken together with proved reserves, are as likely as not to be recovered.

Abbreviations

bbls	*barrels*
bpd	*barrels per day*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
mmbtu	*million British Thermal Units*
mmlt	*million long tons*
tcfe	*trillion cubic feet equivalent*
ASP	*alkali surfactant polymer*
CDOR	*Certificate of Deposit Offered Rate*
CHOPS	*cold heavy oil production with sand*
CNOOC	*China National Offshore Oil Corporation*
EOR	*enhanced oil recovery*
FEED	*Front end engineering design*
FPSO	*Floating production, storage and offloading vessel*
GAAP	*Generally Accepted Accounting Principles*
GJ	*gigajoule*
LIBOR	*London Interbank Offered Rate*
MD&A	*Management's Discussion and Analysis*
MW	*megawatt*
NGL	*natural gas liquids*
NIT	*NOVA Inventory Transfer*
NYMEX	*New York Mercantile Exchange*
OPEC	*Organization of Petroleum Exporting Countries*
PSC	*production sharing contract*
PIIP	*Petroleum initially-in-place*
SAGD	*Steam assisted gravity drainage*
SEDAR	*System for Electronic Document Analysis and Retrieval*
WI	*working interest*
WTI	*West Texas Intermediate*
C-NLOPB	*Canada-Newfoundland and Labrador Offshore Petroleum Board*

11.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, with the participation of the Chief Executive Officer and the Chief Financial Officer, have evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2010, and have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by Husky in reports that it files or submits under the Securities Exchange Act of 1934 and Canadian securities laws is (i) recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and Canadian securities laws and (ii) accumulated and communicated to Husky's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management is responsible for establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2010, management assessed the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective and that there are no material weaknesses in Husky's internal control over financial reporting that have been identified by management.
4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2010, has also issued a report on internal controls over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States) which attests to management's assessment of Husky's internal controls over financial reporting.

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2010, that have materially affected, or are reasonably likely to materially affect its internal control over financial reporting.

12.0 Selected Quarterly Financial & Operating Information

Segmented Financial Information

	Upstream				Midstream							
					Upgrading				Infrastructure and Marketing			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
2010												
Sales and operating revenues, net of royalties	**1,276**	**1,152**	**1,086**	**1,252**	**366**	**291**	**405**	**508**	**1,936**	**1,872**	**1,959**	**2,087**
Costs and expenses												
Operating, cost of sales, selling and general	**419**	**399**	**396**	**383**	**334**	**284**	**354**	**467**	**1,860**	**1,827**	**1,895**	**2,010**
Depletion, depreciation and amortization	**404**	**399**	**394**	**375**	**42**	**33**	**16**	**9**	**13**	**10**	**10**	**10**
Interest - net	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Foreign exchange	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
	823	**798**	**790**	**758**	**376**	**317**	**370**	**476**	**1,873**	**1,837**	**1,905**	**2,020**
Earnings (loss) before income taxes	**453**	**354**	**296**	**494**	**(10)**	**(26)**	**35**	**32**	**63**	**35**	**54**	**67**
Current income taxes (recoveries)	**(68)**	**13**	**16**	**16**	**(20)**	**(4)**	**15**	**10**	**15**	**16**	**16**	**15**
Future income taxes (reduction)	**199**	**89**	**70**	**127**	**17**	**(3)**	**(5)**	**(1)**	**2**	**(6)**	**(2)**	**3**
Net earnings (loss)	**322**	**252**	**210**	**351**	**(7)**	**(19)**	**25**	**23**	**46**	**25**	**40**	**49**
Capital expenditures [2]	**1,280**	**719**	**490**	**682**	**50**	**101**	**16**	**9**	**15**	**10**	**12**	**3**
Total assets	**18,179**	**17,038**	**16,768**	**16,611**	**2,075**	**1,360**	**1,424**	**1,465**	**1,368**	**1,678**	**1,692**	**1,549**
2009												
Sales and operating revenues, net of royalties	1,200	1,040	1,167	1,045	445	415	399	313	1,692	1,497	1,760	2,035
Costs and expenses												
Operating, cost of sales, selling and general	372	382	364	377	415	403	389	254	1,615	1,428	1,678	1,948
Depletion, depreciation and amortization	351	327	348	371	9	9	8	8	9	9	9	9
Interest - net	–	–	–	–	–	–	–	–	–	–	–	–
Foreign exchange	–	–	–	–	–	–	–	–	–	–	–	–
	723	709	712	748	424	412	397	262	1,624	1,437	1,687	1,957
Earnings (loss) before income taxes	477	331	455	297	21	3	2	51	68	60	73	78
Current income taxes (recoveries)	96	252	270	291	57	18	17	19	26	25	25	25
Future income taxes (reduction)	47	(166)	(138)	(205)	(50)	(17)	(17)	(4)	(7)	(7)	(5)	(3)
Net earnings (loss)	334	245	323	211	14	2	2	36	49	42	53	56
Capital expenditures [2]	841	412	405	668	20	17	12	19	–	7	5	14
Total assets	16,338	15,853	15,877	16,025	1,427	1,395	1,429	1,387	1,712	1,193	1,364	1,336

(1) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.*
(2) *Excludes capitalized costs related to asset retirement obligations incurred during the period.*

Downstream								Corporate and Eliminations [1]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
835	**834**	**700**	**606**	**1,824**	**1,683**	**1,881**	**1,719**	**(1,506)**	**(1,424)**	**(1,463)**	**(1,701)**	**4,731**	**4,408**	**4,568**	**4,471**
758	**741**	**659**	**570**	**1,739**	**1,633**	**1,856**	**1,718**	**(1,400)**	**(1,413)**	**(1,484)**	**(1,664)**	**3,710**	**3,471**	**3,676**	**3,484**
18	**22**	**25**	**26**	**51**	**47**	**47**	**46**	**19**	**19**	**19**	**19**	**547**	**530**	**511**	**485**
–	**–**	**–**	**–**	**–**	**1**	**–**	**1**	**50**	**53**	**55**	**48**	**50**	**54**	**55**	**49**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**7**	**11**	**(19)**	**(1)**	**7**	**11**	**(19)**	**(1)**
776	**763**	**684**	**596**	**1,790**	**1,681**	**1,903**	**1,765**	**(1,324)**	**(1,330)**	**(1,429)**	**(1,598)**	**4,314**	**4,066**	**4,223**	**4,017**
59	**71**	**16**	**10**	**34**	**2**	**(22)**	**(46)**	**(182)**	**(94)**	**(34)**	**(103)**	**417**	**342**	**345**	**454**
12	**14**	**15**	**15**	**•–**	**–**	**–**	**–**	**24**	**24**	**22**	**22**	**(37)**	**63**	**84**	**78**
3	**5**	**(11)**	**(12)**	**12**	**1**	**(8)**	**(17)**	**(84)**	**(64)**	**(49)**	**(69)**	**149**	**22**	**(5)**	**31**
44	**52**	**12**	**7**	**22**	**1**	**(14)**	**(29)**	**(122)**	**(54)**	**(7)**	**(56)**	**305**	**257**	**266**	**345**
80	**84**	**65**	**16**	**122**	**62**	**51**	**22**	**51**	**10**	**4**	**2**	**1,598**	**986**	**638**	**734**
1,582	**1,472**	**1,473**	**1,442**	**5,078**	**5,080**	**5,122**	**4,918**	**851**	**559**	**626**	**963**	**29,133**	**27,187**	**27,105**	**26,948**
634	786	587	488	1,169	1,555	1,497	1,128	(1,535)	(1,390)	(1,494)	(1,359)	3,605	3,903	3,916	3,650
596	680	506	422	1,189	1,490	1,237	1,041	(1,520)	(1,405)	(1,438)	(1,300)	2,667	2,978	2,736	2,742
24	23	23	23	47	48	49	50	15	14	13	9	455	430	450	470
–	–	–	–	1	1	–	1	52	52	50	37	53	53	50	38
–	–	–	–	–	–	–	–	(6)	-	34	(33)	(6)	–	34	(33)
620	703	529	445	1,237	1,539	1,286	1,092	(1,459)	(1,339)	(1,341)	(1,287)	3,169	3,461	3,270	3,217
14	83	58	43	(68)	16	211	36	(76)	(51)	(153)	(72)	436	442	646	433
9	13	8	8	3	–	–	–	25	26	25	24	216	334	345	367
(5)	11	8	5	(28)	6	77	13	(57)	(57)	(54)	(68)	(100)	(230)	(129)	(262)
10	59	42	30	(43)	10	134	23	(44)	(20)	(124)	(28)	320	338	430	328
38	18	20	5	137	54	43	26	14	9	7	6	1,050	517	492	738
1,430	1,587	1,624	4,504	4,771	4,647	5,081	2,259	617	1,478	1,486	453	26,295	26,153	26,861	25,964

Segmented Operational Information

		2010				2009			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream									
Daily production, before royalties									
Light crude oil & NGL *(mbbls/day)*		**75.1**	**84.4**	**78.7**	**84.3**	76.7	62.5	99.3	119.0
Medium crude oil *(mbbls/day)*		**25.3**	**25.7**	**25.1**	**25.3**	24.8	24.8	25.6	26.3
Heavy crude oil *(mbbls/day)*		**74.6**	**72.4**	**74.6**	**76.4**	78.6	75.7	78.1	82.1
Bitumen *(mbbls/day)*		**23.1**	**21.9**	**21.5**	**22.6**	23.3	24.0	22.2	22.7
		198.1	**204.4**	**199.9**	**208.6**	203.4	187.0	225.2	250.1
Natural gas *(mmcf/day)*		**494.2**	**505.5**	**503.9**	**523.7**	528.7	535.0	552.3	551.2
Total production *(mboe/day)*		**280.5**	**288.7**	**283.9**	**295.9**	291.5	276.2	317.2	342.0
Average sales prices									
Light crude oil & NGL *($/bbl)*		**82.90**	**73.88**	**75.61**	**76.72**	73.98	67.56	65.32	50.42
Medium crude oil *($/bbl)*		**65.75**	**60.88**	**63.90**	**69.30**	65.78	61.28	58.32	40.68
Heavy crude oil *($/bbl)*		**58.82**	**56.96**	**56.18**	**63.31**	61.55	59.21	54.22	35.80
Bitumen *($/bbl)*		**59.14**	**55.41**	**52.58**	**61.82**	60.70	58.44	53.32	34.23
Natural gas *($/mcf)*		**3.52**	**3.50**	**3.45**	**4.81**	3.94	2.84	3.26	5.31
Operating costs *($/boe)*		**13.85**	**13.24**	**13.41**	**12.81**	12.24	13.14	11.05	11.10
Operating netbacks [1]									
Light crude oil *($/boe)* [2]		**53.37**	**47.42**	**43.96**	**46.02**	46.94	38.37	40.58	32.95
Medium crude oil *($/boe)* [2]		**38.62**	**33.43**	**32.45**	**38.02**	39.87	32.47	33.55	17.64
Heavy crude oil *($/boe)* [2]		**33.91**	**32.32**	**31.80**	**38.16**	37.16	37.21	33.85	18.16
Bitumen *($/boe)* [2]		**29.88**	**28.09**	**26.14**	**31.49**	26.59	38.10	33.75	14.54
Natural gas *($/mcfge)* [3]		**2.02**	**1.55**	**1.60**	**2.93**	2.29	1.16	1.73	2.72
Total *($/boe)* [2]		**32.83**	**29.67**	**28.17**	**33.83**	32.02	27.30	29.03	22.44
Net wells drilled [4]									
Exploration	Oil	**12**	**17**	**3**	**19**	5	1	1	2
	Gas	**9**	**6**	**1**	**15**	–	1	3	18
	Dry	**–**	**1**	**–**	**7**	1	–	–	5
		21	**24**	**4**	**41**	6	2	4	25
Development	Oil	**257**	**235**	**52**	**179**	116	72	19	71
	Gas	**38**	**6**	**–**	**9**	8	2	2	49
	Dry	**2**	**2**	**–**	**5**	2	1	–	4
		297	**243**	**52**	**193**	126	75	21	124
		318	**267**	**56**	**234**	132	77	25	149
Success ratio *(percent)*		**99**	**99**	**100**	**95**	98	99	100	94
Midstream									
Synthetic crude oil sales *(mbbls/day)*		**45.1**	**21.0**	**58.0**	**68.6**	64.5	58.6	63.1	61.0
Upgrading differential *($/bbl)*		**16.39**	**13.80**	**15.44**	**12.54**	13.06	10.16	8.31	16.74
Pipeline throughput *(mbbls/day)*		**501**	**489**	**537**	**524**	498	498	534	529
Canadian Refined Products									
Refined products sales volumes									
Light oil products *(million litres/day)*		**8.7**	**8.5**	**7.8**	**7.6**	7.7	7.8	7.4	7.6
Asphalt products *(mbbls/day)*		**27.5**	**30.9**	**19.2**	**18.7**	18.9	32.4	17.5	21.7
Refinery throughput									
Lloydminster refinery *(mbbls/day)*		**29.0**	**28.9**	**26.1**	**27.0**	22.2	27.5	17.8	28.8
Prince George refinery *(mbbls/day)*		**11.5**	**11.9**	**6.9**	**9.7**	10.4	10.2	10.0	10.6
Refinery utilization *(percent)*		**99**	**100**	**80**	**90**	82	94	70	99

[1] *Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.*
[2] *Includes associated co-products converted to boe.*
[3] *Includes associated co-products converted to mcfge.*
[4] *Western Canada and Oil Sands*

Segmented Capital Expenditures

($ millions)	2010 Q4	2010 Q3	2010 Q2	2010 Q1	2009 Q4	2009 Q3	2009 Q2	2009 Q1
Upstream								
Western Canada	**1,022**	**502**	**287**	**424**	579	152	109	349
Atlantic Region	**107**	**124**	**108**	**150**	95	111	160	208
Northwest United States	**–**	**–**	**–**	**–**	10	3	7	5
International	**151**	**93**	**95**	**108**	157	146	129	106
	1,280	**719**	**490**	**682**	841	412	405	668
Midstream								
Upgrader	**50**	**101**	**16**	**9**	20	17	12	19
Infrastructure and Marketing	**15**	**10**	**12**	**3**	–	7	5	14
	65	**111**	**28**	**12**	20	24	17	33
Downstream								
Canadian Refined Products	**80**	**84**	**65**	**16**	38	18	20	5
U.S. Refining and Marketing	**122**	**62**	**51**	**22**	137	54	43	26
	202	**146**	**116**	**38**	175	72	63	31
Corporate	**51**	**10**	**4**	**2**	14	9	7	6
	1,598	**986**	**638**	**734**	1,050	517	492	738

Note: Excludes capitalized costs related to asset retirement obligations incurred during the period.

Exhibit No.	Description
23.1	Consent of KPMG LLP, independent registered public accounting firm.
23.2	Consent of McDaniel and Associates Consultants Ltd., independent engineers.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
99.1	Supplemental Disclosures of Oil and Gas Activities

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors of Husky Energy Inc.

We consent to the incorporation by reference in the registration statement (No. 333-157389) on Form F-9 of Husky Energy Inc. of our reports dated March 8, 2011, with respect to the consolidated balance sheets of Husky Energy Inc as at December 31, 2010, 2009 and 2008, and the consolidated statements of earnings and comprehensive income, changes in shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2010, and the effectiveness of internal control over financial reporting as of December 31, 2010, which reports appear in the December 31, 2010 annual report on Form 40-F of Husky Energy Inc.

/s/ KPMG LLP .
KPMG LLP
Chartered Accountants
Calgary, Canada
March 8, 2011

Exhibit 23.2

Consent of Independent Engineers

We refer to our report auditing estimates of the natural gas, natural gas liquids and conventional oil reserves attributable to Husky Energy Inc. (the "Company") as of December 31, 2010 (the "Report").

We hereby consent to references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and the Company's registration statement on Form F-9 (File No. 333-157389). We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2010, dated March 8, 2011, and that we have no reason to believe that there are any misrepresentations in the information contained in it that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B.J. Wurster, P.Eng.
B.J. Wurster, P.Eng.
Vice President
Calgary, Alberta, Canada
March 8, 2011

Exhibit 31.1

Certification Pursuant to
Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934,
As Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Asim Ghosh, certify that:

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

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 8, 2011

/s/ Asim Ghosh
Asim Ghosh
President & Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934,
As Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Alister Cowan, certify that:

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

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 8, 2011

/s/ Alister Cowan
Alister Cowan
Vice President & Chief Financial Officer

Exhibit 32.1

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), **I, Asim Ghosh, President & Chief Executive Officer of the Company**, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date**:** March 8, 2011

/s/ Asim Ghosh
Asim Ghosh
President & Chief Executive Officer

Exhibit 32.2

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), **I, Alister Cowan, Vice President & Chief Financial Officer of the Company**, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date**:** March 8, 2011

/s/ Alister Cowan
Alister Cowan
Vice President & Chief Financial Officer

Exhibit 99.1

Disclosure about Oil and Gas Producing Activities – Accounting Standards Codification 932, "Extractive Activities – Oil and Gas" (unaudited)

The following disclosures have been prepared in accordance with FASB Accounting Standards Codification 932, "Extractive Activities – Oil and Gas":

Oil and Gas Reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered:(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

Subsequent to December 31, 2010, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of developed or undeveloped reserves as of that date.

Note that the numbers in each column of the tables throughout this exhibit may not add due to rounding.

Results of Operations for Producing Activities [(1) (2)] **(unaudited)**

	Canada			International			Total		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
	($ millions except per boe amounts)								
Oil and gas production revenue	4,521	4,280	7,667	251	237	315	4,772	4,517	7,982
Operating costs									
Lease operating expenses	1,450	1,357	1,469	30	30	25	1,480	1,387	1,494
Production taxes	61	65	93	—	—	—	61	65	93
Asset retirement obligation accretion	43	39	44	1	1	1	44	40	45
	1,554	1,461	1,606	31	31	26	1,585	1,492	1,632
Depreciation, depletion and amortization	1,381	1,324	1,457	191	73	48	1,572	1,397	1,505
Earnings before taxes	1,586	1,495	4,604	29	133	241	1,615	1,628	4,845
Income taxes	460	449	1,409	8	40	74	468	489	1,483
Results of operations	1,126	1,046	3,195	21	93	167	1,147	1,139	3,362
Amortization rate per gross boe	13.25	11.92	11.58	48.60	17.83	10.93	14.53	12.14	11.56
Amortization rate per net boe	16.17	14.59	14.47	65.33	21.60	14.77	17.79	14.85	14.48

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 2010 amounted to $1,413 million (2009 — $1,341 million; 2008 — $1,435 million). Income taxes for Canadian producing activities under U.S. GAAP for 2010 amounted to $451 million (2009 — $444 million; 2008 — $1,415 million).

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities [1] **(unaudited)**

	Canada	International	Total
		($ millions)	
2010			
Property acquisition			
Proved	389	—	389
Unproved	62	—	62
Exploration	428	381[2]	809
Development	2,088	63[3]	2,151
Capitalized interest	16	14	30
Total costs incurred	2,983	458	3,441
Less: Proved acquisitions	389	—	389
Capitalized interest	16	14	30
Finding and development costs	2,578	444	3,022
2009			
Property acquisition			
Proved	220	—	220
Unproved	87	2	89
Exploration	259	549	808
Development	1,225	17	1,242
Capitalized interest	16	—	16
Total costs incurred	1,807	568	2,375
Less: Proved acquisitions	220	—	220
Capitalized interest	16	—	16
Finding and development costs	1,571	568	2,139
2008			
Property acquisition			
Proved	241	—	241
Unproved	244	45	289
Exploration	596	240	836
Development	2,209	5	2,214
Capitalized interest	—	—	—
Total costs incurred	3,290	290	3,580
Less: Proved acquisitions	241	—	241
Capitalized interest	—	—	—
Finding and development costs	3,049	290	3,339

Notes:

(1) Development costs incurred exclude actual retirement expenditures and include asset retirement obligation incurred. Asset retirement obligation incurred for 2010 was $287 million (2009 - $75 million; 2008 - $40 million).

(2) Total international exploration costs of $381 million pertain to the following countries: China - $369 million and Indonesia - $12 million. International exploration costs for Greenland - $3 million are included in the Atlantic Region within Canada exploration costs of $428 million.

(3) Total international development costs of $63 million pertain to the following countries: China - $60 million and Libya - $3 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 (i) drilling and equipping development wells; (ii) facilities to extract, treat, gather and store oil and gas; (iii) 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, 2010, by the year in which the costs were incurred:

Withheld Costs (unaudited)	**Total**	**2010**	**2009**	**2008**	**Prior to 2008**
			($ millions)		
Property acquisitions					
Canada	67	—	—	—	67
International	30	—	—	—	30
	97	—	—	—	97
Exploration					
Canada	2,546	563	1,189	794	—
International	479	437	42	—	—
	3,025	1,000	1,231	794	—
Development					
Canada	968	436	47	485	—
International	32	9	5	5	13
	1,000	445	52	490	13
Capitalized interest					
Canada	120	—	16	6	98
	4,242	1,445	1,299	1,290	208

Capitalized Costs Relating to Oil and Gas Producing Activities (unaudited)

	Canada	**International**	**Total**
2010		($ millions)	
Proved properties [1]	25,217	1,252	26,469
Unproved properties	3,406	836	4,242
	28,623	2,088	30,711
Accumulated DD&A	13,439	750	14,189
Net Capitalized Costs [2]	15,184	1,338	16,522
2009			
Proved properties [1]	22,663	863	23,526
Unproved properties	3,125	827	3,952
	25,788	1,690	27,478
Accumulated DD&A	12,129	559	12,688
Net Capitalized Costs [2]	13,659	1,131	14,790
2008			
Proved properties [1]	21,515	580	22,095
Unproved properties	2,703	485	3,188
	24,218	1,065	25,283
Accumulated DD&A	10,946	486	11,432
Net Capitalized Costs [2]	13,272	579	13,851

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**
		($ millions)	
2010	844	11	855
2009	557	11	568
2008	488	6	494

(2) The net capitalized costs for Canadian oil and gas exploration, development and producing activities under U.S. GAAP for 2010 were $14,848 million (2009 - $13,292 million; 2008 - $12,921 million). The net capitalized costs for International property oil & gas exploration, development and producing activities under U.S. GAAP for 2010 were $1,337 million (2009 - $1,130 million; 2008 - $578 million). Please refer to the Company's Form 40-F for an explanation of the differences between Canadian and U.S. GAAP for oil and gas activities.

Oil and Gas Reserve Information (unaudited)

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

	Canada		International		Total		
Reserves	**Crude Oil & NGL**	**Natural Gas**	**Crude Oil & NGL**	**Natural Gas**	**Crude Oil & NGL**	**Natural Gas**	**Total Company**
	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmboe)
Net proved reserves [(1) (2) (3) (4)]							
End of year 2007	544	1,854	8	—	552	1,854	861
Revisions	(54)	2	1	—	(53)	2	(53)
Purchases	8	89	—	—	8	89	22
Sales	(1)	(16)	—	—	(1)	(16)	(3)
Improved recovery	10	28	—	—	10	28	15
Discoveries and extensions	30	125	—	—	30	125	51
Production	(73)	(170)	(3)	—	(76)	(170)	(104)
End of year 2008	464	1,912	6	—	470	1,912	789
Revisions [(5)]	60	(315)	5	—	65	(315)	12
Purchases	10	16	—	—	10	16	12
Sales	—	—	—	—	—	—	—
Improved recovery	6	—	—	—	6	—	6
Discoveries and extensions	81	67	—	—	81	67	93
Production	(63)	(167)	(3)	—	(66)	(167)	(94)
End of year 2009	558	1,513	8	—	566	1,513	818
Revisions	(6)	(41)	1	—	(5)	(41)	(12)
Purchases	2	161	—	—	2	161	28
Sales	—	(1)	—	—	—	(1)	—
Improved recovery	4	1	—	—	4	1	4
Discoveries and extensions	87	129	5	147	92	277	139
Production	(63)	(175)	(3)	—	(66)	(175)	(95)
End of year 2010	582	1587	11	147	593	1734	882
Net proved developed reserves [(1) (2) (3) (4)]							
End of year 2007	407	1,494	8	—	415	1,494	664
End of year 2008	357	1,524	6	—	363	1,524	617
End of year 2009	360	1,265	8	—	368	1,265	579
End of year 2010	335	1327	6	—	341	1327	562

Notes:

(1) Net reserves are the Company's lesser 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 remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

(3) Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

(4) Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(5) Included in revisions is a reduction of 38 net mmboe of proved reserves as a result of the revised SEC guidelines for the method of determining prices on which the economics of the reserves are based.

(6) The Company's reserve replacement ratio[(a)] for the last three years was as follows:

Net proved oil and gas reserves	2010	2009	2008
Excluding acquisition & divestiture	138%	118%	13%
Including acquisition & divestiture	167%	130%	31%

Note:

(a) Reserve replacement ratio calculated as reserves added during the period divided by total production during the period.

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

The following information has been developed utilizing procedures prescribed by FASB Accounting Standards Codification 932, "Extractive Activities – Oil and Gas" 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.

The future cash flows presented below are based on 2010 average sales prices and cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

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

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2010 was based on the NYMEX 2010 average natural gas cash market price of U.S. $4.39/mmbtu (2009 average — U.S. $3.87/mmbtu; 2008 year-end — U.S. $5.41/mmbtu) and on crude oil prices computed with reference to the 2010 average WTI spot price of U.S. $79.46/bbl (2009 average — U.S. $61.18/bbl; 2008 year-end — U.S. $44.60/bbl).

	Canada [1]			International [1]			Total [1]		
Standardized Measure (unaudited)	2010	2009	2008	2010	2009	2008	2010	2009	2008
					($ millions)				
Future cash inflows	40,840	34,528	29,640	1,582	593	278	42,422	35,121	29,918
Future production costs	14,682	12,749	11,596	576	119	99	15,258	12,868	11,695
Future development costs	7,605	6,487	4,006	182	21	14	7,787	6,508	4,020
Future income taxes	4,752	3,989	3,667	255	144	48	5,007	4,133	3,715
Future net cash flows	13,801	11,303	10,371	570	309	117	14,371	11,612	10,488
Annual 10% discount factor	6,010	4,781	4,121	216	39	8	6,226	4,820	4,129
Standardized measure of discounted future net cash flows	7,791	6,522	6,250	354	270	109	8,145	6,792	6,359

Note:

(1) The schedules above are calculated using year-end prices, costs, statutory income tax rates for 2008 and for 2009 and 2010, year average prices and year-end costs, statutory income tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future change in oil and gas prices and in production and development costs are excluded.

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

	Canada [1]			International [1]			Total [1]		
	2010	2009	2008	2010	2009	2008	2010	2009	2008
					($ millions)				
Present value at January 1	6,522	6,250	14,378	270	109	455	6,792	6,359	14,833
Sales and transfers, net of production costs	(3,129)	(2,913)	(6,167)	(227)	(215)	(294)	(3,356)	(3,128)	(6,461)
Net change in sales and transfer prices, net of development and production costs	2,982	1,918	(10,514)	99	187	(338)	3,081	2,105	(10,852)
Development cost incurred that reduced future development costs	2,697	1,518	2,450	6	5	5	2,703	1,523	2,455
Changes in estimated future development costs	(2,639)	(2,985)	(1,582)	(1)	(10)	(6)	(2,640)	(2,995)	(1,588)
Extensions, discoveries and improved recovery, net of related costs	1,235	1,881	1,572	169	23	18	1,404	1,904	1,590
Revisions of quantity estimates	(68)	313	107	43	241	12	(25)	554	119
Accretion of discount	911	863	2,032	39	16	66	950	879	2,098
Sale of reserves in place	(4)	—	(104)	0	—	—	(4)	—	(104)
Purchase of reserves in place	247	268	368	0	—	—	247	268	368
Changes in timing of future net cash flows and other	(579)	(388)	155	—	(6)	27	(579)	(394)	182
Net change in income taxes	(384)	(203)	3,555	(44)	(80)	164	(428)	(283)	3,719
Net increase (decrease)	1,269	272	(8,128)	84	161	(346)	1,353	433	(8,474)
Present value at December 31	7,791	6,522	6,250	354	270	109	8,145	6,792	6,359

Note:

(1) The schedules above are calculated using year-end prices, costs, statutory income tax rates for 2008 and for 2009 and 2010, year-end average prices and year-end 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.